VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

September 28, 2023

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.: 23-242
NRA/GDM: R0
Docket Nos.: 50-280/281
License Nos.: DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION ENERGY VIRGINIA)
SURRY POWER STATION UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT – REVISION 55

Pursuant to 10 CFR 50.71(e), Dominion Energy Virginia submits Revision 55 to the Updated Final Safety Analysis Report (UFSAR) for Surry Power Station (SPS).

The complete SPS UFSAR, Revision 55, is provided in Enclosure 1 and contains Security-Related Information that Dominion Energy Virginia requests be withheld from public disclosure in accordance with 10 CFR 2.390. A public version of the SPS UFSAR, Revision 55, is included in Enclosure 2.

A list and brief description of changes since the previous annual update is provided in the Revision Summary located in the Frontmatter of each enclosure. Third-party documents included by reference in the SPS UFSAR may not be text searchable.

If you have any questions or require additional information regarding this submittal, please contact Gary D. Miller at (804) 273-2771.

Sincerely,

James E. Holloway
Vice President – Nuclear Engineering & Fleet Support

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by James E. Holloway, who is Vice President – Nuclear Engineering & Fleet Support of Dominion Energy Virginia. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 28th day of September 2023.
My Commission Expires: March 31, 2026

DIANE E. AITKEN
NOTARY PUBLIC
REGISTRATION # 7763114
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES
MARCH 31, 2026

Notary Public

ENCLOSURE 1 TO THIS LETTER CONTAINS ~~SECURITY-RELATED INFORMATION WHICH IS TO BE WITHHELD FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390.~~
UPON REMOVAL OF ENCLOSURE 1, THIS PAGE IS DECONTROLLED.

Enclosures:

1. Surry Power Station, Updated Final Safety Analysis Report, Revision 55 **[Security-Related Information – Withhold Under 10 CFR 2.390]**
2. Surry Power Station, Updated Final Safety Analysis Report, Revision 55 [Redacted]

Commitments made in this letter: None

cc: Regional Administrator, Region II (w/enclosures)
U. S. Nuclear Regulatory Commission
Marquis One Tower
Suite 1200
245 Peachtree Center Avenue, NE
Atlanta, Georgia 30303-1257

Mr. John Klos (w/enclosures)
NRC Project Manager – Surry Power Station
U. S. Nuclear Regulatory Commission
One White Flint North
Mail Stop 09 E-03
11555 Rockville Pike
Rockville, Maryland 20852-2738

NRC Senior Resident Inspector (w/enclosures)
Surry Power Station

Serial No.: 23-242
Docket Nos.: 50-280/281

ENCLOSURE 2

SURRY POWER STATION
UPDATED FINAL SAFETY ANALYSIS REPORT

REVISION 55

[REDACTED]

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION ENERGY VIRGINIA)
SURRY POWER STATION UNITS 1 AND 2

SURRY POWER STATION

UPDATED FINAL SAFETY ANALYSIS REPORT

Revision 55 - 09/28/23

Intentionally Blank

Click on Change Package Number Highlighted in Red to View Change Request.

REVISION SUMMARY

Revision 55—Updated Online 09/28/23

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Tables 9.3-1 and 9.3-2 [SPS-UCR-2023-003]	Unit 1 and 2 RHR HX (1-RH-E-1B and 2-RH-E-1B) Replacement Interim Phased Change SU-18-00123, SU-18-00124
Sections 15.2 and 15.2.3, Table 15.2-1 [SPS-UCR-2021-015]	[Evaluation Methodology and Acceptance Criteria Change for the Reclassification of the Turbine Building as a Tornado Resistant Structure License Amendments #310 (U1) and #310 (U2) (ML23100A065 dated 04-25-2023)]
Sections 6.1, 6.2.2.2.4, 6.2.3.3, 6.3.1.1, 6.3.1.2.1, 6.3.1.3.1, 6.3 References, 18.1.3, Tables 6.3-1, 7.5-2, 15.2-1, Figures 6.1-2, 6.3-1a, 6.3-1b, 15.1-2 [SPS-UCR-2020-010	Unit 2 Refueling Water Chemical Addition Tank (CAT) Removal and Sodium Hydroxide (NaOH) pH Buffer Elimination SU-19-01128
Section 14.5.5.3 [SPS-UCR-2023-009]	[UFSAR Change Request to Correct Typo in Outside Recirculation Spray System Leakage Value in Section 14.5.5.3 [CR1219500]
Table 11.3-2 and Figure 11.3-3 [SPS-UCR-2023-004]	FSAR Change for EC SU-22-00144 to document Unit 2 lncore Sump Room Permanent Shielding EC SU-22-00144 - Unit 2 lncore Sump Room Permanent Shielding
Sections 3.2, 3.2.2.1, 3.2 References, 3.4.1.1, 3.4.1.1.1 through 3.4.1.1.5, 3.4.1.2, 3.4 References, 3.5.2.1.5, 3.5.2.6.1, 3.5.2.6.1.1, 3.5 References, 5.4.1.2, 14.3.3.2, 14.3.3.2.1, 14.3.3.2.3, 14.3.3.2.3.1 through 14.3.3.2.3.4 Tables 14.3-6a (deleted) and 14.3-6b (renumbered to 14.3-6) Figures 3.4-1 (deleted), 14.3-24 through 14.3-27 (changed to PAD5 analysis), 14.3-29 through 14.3-32 (deleted) [SPS-UCR-2023-002]	Implementation of PAD5 into the Surry Unit 2 Design Basis ETE-NAF-2023-0006

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 55—Updated Online 09/28/23 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Section 15.2.5 [SPS-UCR-2020-005]	SPS Units 1 and 2 UFSAR Updates for Beyond Design Basis (BDB) Flooding Mods - Penetration Seals SU-18-00167
Section 4.2 (Administrative correction)	Corrected the paragraph numbering in Section 4.2. No text in this section was changed.
Table 6.3-1 [SPS-UCR-2022-023]	Unit 1 Refueling Water Chemical Addition Tank (CAT) Removal and Sodium Hydroxide (NaOH) pH Buffer Elimination DC SU-19-01127, Rev. 1
Sections 5.3.1.4, 6.1, 6.2.2.2.4, 6.2.3.3, 6.3.1.1, 6.3.1.2.1, 6.3.1.3.1, 6.3.1.4.1, 6.3 References, and 18.1.3. Tables 6.2-7, 6.3-1, 7.5-2, and 15.2-1. Figures 6.1-1, 6.3-1, and 15.1-2. [SPS-UCR-2020-009]	Unit 1 Refueling Water Chemical Addition Tank (CAT) Removal and Sodium Hydroxide (NaOH) pH Buffer Elimination SU-19-01127
Section 11.3.2.1, Table 11.3-2, and Figure 11.3-2 [SPS-UCR-2022-019]	Unit 1 Incore Sump Room Permanent Shielding SU-22-00143
Sections 3.4, 3.5.1, 14.1, 14.2.4.1, 14.2.7.2, 14.2.7.3.2, 14.2.8.1, 14.2.9.1.1, 14.2.9.2.2.2, 14.2.10.2, 14.2.10.3, 14.3.2.1, 14.3.2.3, 14.2.1.1, 14.2.1.2, 14.2.2.1, 14.5.3.4.1 14.5.3.4.2, Table 3.4-1, Table 15A-8, Table 15A-9, Figure 14.5-76 [SPS-UCR-2022-002]	Revise SPS UFSAR for Unit 1 Upflow Conversion DC SU-21-00117
Sections 14.1, 14.2.4, and 14.2.5, Figures 14.2-15 and 14.2-16 [SPS-UCR-2022-022]	Update to dropped rod event to account for the disabling of automatic rod withdrawal ETE-NAF-2022-0116
Table 14.3-8 [SPS-UCR-2022-021]	[Correction of Table14.3-8 Break Flow Rates Letter from Virginia Electric and Power Company to the U. S. Nuclear Regulatory Commission, Serial Number 22-257, dated 9-15-22.]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 55—Updated Online 09/28/23 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Sections 1.4.49, 3.2.1, and 14.5, Tables 14.5-1 through 14.5-6, 14.5-16, and 14.5-17, and Figures 14.5-1 through 14.5-14 [SPS-UCR-2022-017]	UFSAR Updates for the Westinghouse Full Spectrum Loss of Coolant Accident Analysis and the Upflow Conversion Assessments on Loss of Coolant Accident Analyses for Surry Unit 1 and Unit 2 ETE-NAF-2022-0048
Section 12.2.1 [SPS-UCR-2022-015]	Remove reference to ANSI 3.1 (Draft 12/79) License Amendment #307 for SPS Units 1&2
Sections 7 Table of contents, 7.7, 7.7.4, and 7.7 References. [SPS-UCR-2022-011]	Detailed Control Room Design Review NRC Generic Letter No. 82-33
Sections: 3.2.1, 3.2.2, 3.2.3.3, 3.2 References 3.4.1.1, 3.4.1.2, 3.4 References 3.5.2.4, 3.5.2.6.1, 3.5 References 5.4.1.2 14.1, 14.3.3.2.1, 14.3.3.2.3, 14.3.3.2.3.1 through 14.3.3.2.3.4, 14.3 References. Tables 3.4-1 and 14.3-6. Figures: 3.4-1, 14.3-24 through 14.3-27 [SPS-UCR-2022-006]	Implementation of PAD5 into the Surry Unit 1 Design Basis for Non-LOCA Events ETE-NAF-2022-0029

Revision 54—Updated Online 09/30/22

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Section 9.14.2, Table 9.14-1 [SPS-UCR-2021-007]	Update UFSAR for vacuum drying system upgrade including new vacuum drying skid installation. SU-20-00157
Sections 14.2.9.2.4, 14.3.1.4.3, 14.3.1.4.4, 14.3.2.4.1, 14.4, 14.5.5.1 Table 14.3-8, 14.3-10, 14.3-14, 14.3-14a, 14.3-14b, 14.3-15, 14.3-16, 14.4-1, 14.4-3 [SPS-UCR-2022-013]	Surry UFSAR Errors Identified As Part Of Millstone FSAR Extent of Condition (CR1195550) CR1195550, SPS-UCR-2017-014
Section 6.2.2.2.4 [SPS-UCR-2022-012]	Updating Information for 2-SI-MOV-2860A SU-10-01041 and ETE-SU-2021-0060

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 54—Updated Online 09/30/22 (continued)

Section	Changes Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Sections 7.7.1, and 7.7.2 [SPS-UCR-2022-009	Main Control Room Safety & Protective Equipment Teperature Limit WCAP 7547-L
Sections 1.1.8, 1.4.49, 5.4, 6.1, 14.5.4, and 14.5.5 [SPS-UCR-2020-015]	UFSAR Change Request for the implementation of updated Loss of Coolant Accident (LOCA) Alternate Source Term (AST) radiological dose analysis LA9170306
Section 4.2.11 [SPS-UCR-2022-005]	UCR for update to Shutdown Risk Program CR1181625
Sections 4.1.4, 4.2.4, 4.3.1.2, 14.5.1.2, 15.6.2, 15.6 References, 15A.3.3, 15A.6 and 18.3.7.3 [SPS-UCR-2020-006]	UFSAR Change Request to obtain NRC Approval to utilize Leak Before Break for Reactor Coolant Piping Branch Lines. NRC License Amendment Nos. 304 & 304 - Leak-Before-Break for Pressurizer Surge, Residual Heat Removal, Safety Injection Accumulator, Reactor Coolant System Bypass and Safety Injection Lines; ML21175A185.
Sections 9.12, 9.12 References, 9B.1.5, 14.4 [SPS-UCR-2021-018]	Surry ISFSI Implementation of NUHOMS EOS 37PTH Dry Storage System ETE-NAF-2021-0103 Rev. 0
Appendix 9B.2.1 [SPS-UCR-2021-011]	Update to UFSAR Appendix 9B heavy loads program description ETE-SU-2021-0037
Sections 3.4.1.1 and 3.4 References [SPS-UCR-2022-001]	UCR for Technical Specification 2.1.A.1.b Peak Fuel Centerline Temperature Change Dominion Energy Letter Serial No. 21-362
Tables 11.3-5 and 11.3-6 [SPS-UCR-2017-005]	SRF Liquid Waste Radiation Monitor DC SU-16-01083; SPS0-SCRN-2017-0068-0
Section 9.10.4.18 and Table 15.2-1 [SPS-UCR-2021-009]	Updating Earthquake and Tornado Criterion Classifications for Mechanical Equipment Room 4 in SPS UFSAR CA8449101 / CR1170083

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 54—Updated Online 09/30/22 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Sections 3.3 and 3.5 [SPS-UCR-2021-012]	UFSAR Change Request for Fuel Rod Axial Blankets ETE-NAF-2021-0079

Revision 53—Updated Online 09/30/21

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Chapter 18 is new (rewritten), Table 18-1 is new (rewritten), Sections 1.1, 1.6.2.3, 2.1.3.1, 4.1, 4.1.4, 4.1.5, 4.3.1.2, Chapter 5 Introduction, 6.1, 7.1, Chapter 8 Introduction, Chapter 9 Introduction, 10.1, 11.1, 11.3.2.9.1, 14B.5.1.6, 15.5.1.8, Tables 9.1-3 and 4.1-8 [SPS-UCR-2021-013]	This update package is required to implement the Subsequent License Renewal UFSAR Supplement required by license condition 3.W.1 of the subsequent renewed operating licenses issued by the NRC for SPS Units 1 and 2 on May 4, 2021. ML20052F523
Sections 5.4.1.3 and 5.4 [SPS-UCR-2020-014	Implementation of PWROG-17034-P-A into the Surry Units 1 and 2 Containment Response Analysis ETE-NAF-2020-0105
Sections 4.1.2.8, 4.1.7.1 4.1.7.2, 4.1.7.3, 4.1.7.4, 4.2.5. 4.3.3.2, 4.3.4, Tables 4.1-12. 4.1-13, 4.1-14, 4.1-15, 4.3-3, 4.3-4 Sections 4.1 and 4.3: References [SPS-UCR-2019-005	UFSAR Change Request Related to NRC Approval of LBDCR/TSCR 456 to revise Surry Power Station Heatup & Cooldown Curves (and related requirements for LTOP and material property basis) for SLR LBDCR/TSCR 456
Section 9.1.2.6.9 [SPS-UCR-2020-011]	Charging Pump Seal Leakage Update SU-20-00152
Chapter 14 / Section 14.5.2 / Tables 14.5-12 to 14.5-16 /Figures 14.5-15 to 14.5-74 [SPS-UCR-2021-008]	Implementation of Surry UFSAR Update to Reflect Framatome's Fuel-Vendor-Independent Small Break Loss of Coolant Accident (FVI-SBLOCA) Methodology. LA7430847

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 53—Updated Online 09/30/21 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Section 3.3.2.3 [SPS-UCR-2021-005]	Update Surry UFSAR Section 3.3.2.3 Positive MTC Description With License Amendment 189 Safety Evaluation Basis. CR1163392 / CA8326544
Section 8.3 and Figure 8.3-1 [SPS-UCR-2020-018]	Hopewell 240 Transmission line Name Change Design Change SU-20-00179
Section 3.5 I, Figures 3.5.9 and 3.5.10 [SPS-UCR-2021-002]	The 15x15 Advanced Debris Filter Bottom Nozzle (ADFBN) is being implemented on the 15x15 Upgrade fuel assembly design beginning with Batch 33 (Cycle 31) for both units. ETE-NAF-2021-0011
Chapter 17 [SPS-UCR-2021-006]	The change is to add "The Dominion QAPD is incorporated by reference and describes how 10 CFR 50, Appendix B requirements are met." to Chapter 17 of the SAR to explicitly identify the Quality Assurance Program Description, DOMQA-1, as incorporated by reference. CR115168 and CA8102163
Section 8.5 [SPS-UCR-2017-001]	Page 8.5-7, added a description of the open phase detection system implemented at switchyard transformer TX-1. Design Change SU-15-01023 implements open phase relays at the 4kV emergency buses.
Section 8.2 [SPS-UCR-2019-004]	Replacement of RSSTC 5KV Cables SU-18-00102
Table 15.2-1 [SPS-UCR-2020-012]	Corrections to Revision Summary and Table 15.2-1 CR1154583

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 52—Updated Online 09/30/20

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Section 7.4.2.5 [SPS-UCR-2017-012]	Instrumentation equipment design modification CA3041565, TSCR 450-3.7
Section 8.3, Figure 8.3-1 [SPS-UCR-2020-007]	Hopewell 212 Transmission line Name Change SU-20-00107
Sections 11.2.5.1, 15.2, 15.2.3, 15.6.1 and Table 15.2-1 [SPS-UCR-2020-002]	SPS Response to RIS 2015-06, "Tornado Missile Protection" ETE-CCE-2018-0002
15.2.3, References 15.2, Table 15.2-1 [SPS-UCR-2019-010]	Surry Tornado Missile Risk Evaluator Implementation ETE-SU-2019-0065
9.10.2.1 [SPS-UCR-2017-011]	Unit 1 and Unit 2 Fire Protection Upgrades. SU-17-00132
9.3.2.2, Table 9.3-2 [SPS-UCR-2020-003]	Correction to Table 9.3-2 CA7434130
Tables 4.1-14, 4.1-15, 4.3-3, 4.3-4 [SPS-UCR-2015-019]	Update to Unit 1 and Unit 2 Reactor Pressure Vessel Toughness Data (Unirradiated) PA3007476
14.2, 14.3, 14.4, 14.5, 6.2, 6.3, 9.6, Tables 14.2-2 through 14.2-4, 14.3-7 through 14.3-16, 14.4-1 through 14.4-3, 14.4-5, 14.4-6, 14.5-7, 14.5-8, 14.5-10, 14.5-11, 6.2-6, 6.3-22 [SPS-UCR-2017-014]	Updated Alternate Source Term Analysis LBDCR/TSCR 405, CR474351, CR1053122
15.2.5 [SPS-UCR-2018-010]	SPS Units 1 and 2 UFSAR Updates for Beyond Design Basis (BDB) Flooding Mods – Roof Parapets SU-18-00114

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 51—09/30/19

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
2.2.1.2, 7.7.1, 9.10.1, 9.10.2.2.5, 9.10.2.2.9, 9.13.1, 9.13.3.10, 11.3.4.7, 12.3, Table 2.2-10, Table 11.3-7 [SPS-UCR-2017-010]	Consolidated Emergency Operations Facility LAR 17-325
8.5 [SPS-UCR-2015-012]	Open phase Condition Detection and Protection Systems. SU-15-01023
10.3.5.2 [SPS-UCR-2018-003]	Auxiliary Feedwater MOV Hot Short Resolution Unit 2. SU-16-00108
4.1 Refs, Table, 4.1-12, Table 4.1-13 [SPS-UCR-2017-006]	Surveillance Capsule Schedule NRC letter 17-243 (draft), ETE-CEP-2017-001; LA3062568
Figure 6.1-2 [SPS-UCR-2017-013]	U2 Hot Short Resolution Charging Cross-tie Relocation SU-17-00135
18.2.16, 18.5 [SPS-UCR-2018-005]	Steam Generator Program reference update PA3063167
8.3, Figure 8.3-1 [SPS-UCR-2014-022]	500kV Switchyard Circuit Breaker CB58202 Tie-in bounding package. SU-14-01148
7.7.1, 9.10.2.6 [SPS-UCR-2016-002]	Update reflects modification to the trunked radio communications system.
8.3 [SPS-UCR-2018-004]	Modified to correct an approved change that was not properly incorporated.

Revision 50—09/27/18

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
18.3.2.4, 18.5 Refs [SPS-UCR-2017-008]	Update reflects license renewal inspection frequency of pressurizer surge lines.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 50—09/27/18 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
10.3.5.2 [SPS-UCR-2017-002]	Update reflects auxiliary feedwater motor operated valves fire-rated cables for Appendix R.
Figure 6.1-1 [SPS-UCR-2017-004]	Update reflects Unit 1 Charging Cross-tie for Appendix R.
2.3.1.2.2 [SPS-UCR-2018-002]	Modified description of the exhaust dampers to correct an error made during UFSAR conversion to electronic.
4.1.4, 7.2.1.2, 7.2.1.8.3, 7.2.2.3, 7.2.3.2.1, 7.2.3.2.2, Table 7.2-3, Table 7.2-4, 7.3.1, 7.3.2, 7.3.2.2.1, 7.3.2.2.3, 7.3.3.2, 7.3.3.3, Figure 7.3-1, 7.4.3.4, 7.4.3.6, 14.1, 14.2.4.1, 14.2.5.4, 14.2.7.2, 14.2.8.1 [SPS-UCR-2016-012]	Update reflects automatic rod withdrawal capability being disabled.
9C.1.1 [SPS-UCR-2017-016]	Update adds description of MER 5 flood dike features.
3.3.3.2.1, 3.3 Refs, 3.5 Refs [SPS-UCR-2017-015]	Update reflects Reload Nuclear Design and CMS5 Methodologies

Revision 49—09/28/17

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 14.3-16 [SPS-UCR-2017-009]	Modified table to correct orientation and restore original isotopes and concentration values.
9.10.4.18 and 10.3.7.1 [SPS-FS-2006-013]	Update reflects Turbine Oil Conditioner System Replacement.
14.2.5, 14.2, and 9.1.3.5 [SPS-UCR-2017-003]	Update reflects Boron Dilution Safety Analysis Revision
10.3.1.4, 10.3.5, and Figure 10.3.8 [SPS-FS-2006-028]	Update reflects installation of Unit 1 condensate air in-leakage subsystem.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 49—09/28/17 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 11.3-5 and Table 11.3-6 [SPS-UCR-2016-009]	Update reflects replacement of the Surry Radwaste Facility ventilation particulate and noble gas monitors.
3.5.2.1 [SPS-UCR-2016-008]	Modified to add description of use of demonstration or lead fuel assemblies.
9.1.3.1, Table 9.1-2, Figure 9.1-1, 9.10.1, 9.10.3.2 [SPS-UCR-2016-007]	Updated to reflect isolation of reactor coolant pump seal cooling and the charging cross-connect during fire events.
14.5.1.4, 14.5.1.7, Table 14.5-1, Table 14.5-6 [SPS-UCR-2016-010]	Updated peak cladding temperatures.
14B.5.1.6.1 [SPS-UCR-2016-011]	Modified high energy line inspection for consistency with technical requirements manual.

Revision 48—09/29/16

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.10.1, 9.10.2.1, 9.10.2.2.5, 9.10.2.2.8, 9.10.2.2.9, 9.10.2.8 [SPS-UCR-2016-005]	Update reflects code evaluations completed to address code deficiencies are included in the Appendix R report.
7.4.3.2 [SPS-UCR-2015-008]	Corrected source range pre-amplifier self test frequencies.
Figure 15.1-2 [SPS-UCR-2016-006]	Added note to Figure that refers the reader to the referenced drawing.
3.5.2.6.1 [SPS-UCR-2015-020]	Update reflects ASME revised stress criterion for optimized Zirlo^{TM} high performance fuel cladding
14.1, 14.2.7.2, 14.2.9.1.1, 14.4.1.2 [SPS-UCR-2016-003]	Update reflects increased statistical/deterministic Fdelta H limits
Table 4.1-5, 9.1.2.1 [SPS-UCR-2015-001]	Update reflects reactor coolant pump abeyance seal upgrade

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 48—09/29/16 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.10.4.8 [SPS-UCR-2015-009]	Update clarifies component cooling pump classification.
Table 5.2-1, Table 5.2-2, 6.2.2.1.4, 6.3.1.3.4, 9.1.2.1, 10.3.5.2 [SPS-UCR-2012-011]	Update reflects addition of FLEX mechanical connections to the AFW, CH, CS & SI systems to mitigate effects of a Beyond Design Basis Event.
9.10.2.6, 7.7.1 [SPS-UCR-2014-014]	Update reflects addition of communication equipment for offsite communication to mitigate effects of a Beyond Design Basis Event.
7.7.2, 7.10.2, 8.4.3, 9.1.2.1, 10.3.1.2, 14.3.1.5 [SPS-UCR-2015-010]	Update reflects addition of electrical and mechanical connections to the remote monitoring panels, CH, and backup IA systems to mitigate effects of a Beyond Design Basis Event.
8.4.5 [SPS-UCR-2015-017]	Reflects using LEDs for emergency lighting systems.
8.4.6 [FS-2008-005]	Updated to reflect the TSC Alternate Power Source - Final Package
6.2.2.2.4, 9.3.2.2.3 [SPS-UCR-2010-027]	Updated to reflect MOVs with the pressure locking modification
Table 14.5-6 [SPS-UCR-2015-011]	Reflects the Westinghouse LBLOCA error
10.3.3.1, 14b.5.1.6.1, 18.2.1 [SPS-UCR-2015-016]	Update reflects Relocation of TS augmented inspection requirements (except RCP flywheel) to the TRM
2.2.1.2, Table 2.2-8, Table 2.2-9, Table 11A-4, Table 11A-5, Table 11A-6, Table 11A-7 [SPS-UCR-2015-018]	Revised the Primary Met Tower Instrument Height

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 47—09/30/15

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
6.2.2.2.4 [SPS-UCR-2011-001]	Reflects additional MOV pressure locking valve modifications.
3.5.2.1, 3.5.2.1.2, Table 3.5-3, Figure 3.5-9 [SPS-UCR-2015-006]	Reflects implementation of the Westinghouse integral nozzle design
9.8.1, 9.8.2, Table 9,8-1, 9.10.1, 10.3.9.3, Table 10.3-4, Figure 10.3-11 [SPS-UCR-2010-010]	Reflects the Compressed Air System Upgrade
9.10.1 [SPS-UCR-2013-014]	Update to include the Beyond Design Basis Storage Building
3.5.2.3 [SPS-UCR-2014-001]	Reflects Re-Insertion of Secondary Source Assemblies – Bounding Configuration
14.5.3.4.1, References 55, 56, 57, 58, 59, and 60, Table 14.5-18, 15.6.2.1, 15.6.2.2.1 [SPS-UCR-2015-014]	Update to include Beyond Design Basis Offsite Communications
3.6.1.1 [SPS-UCR-2015-005]	Revised Direct Power Distribution Measurements for Start-Up to be made at 50% RTP rather than 30% RTP
Figure 8.3-1 [SPS-UCR-2015-013]	Update to include the 500kV Switchyard Circuit Breaker CB58202 Tie-in Interim Package
8.3, Figure 8.3-1 [SPS-UCR-2014-003]	Reflects Removal of the 1G/2G 34.5KV Overhead Feeders
14.2 Refs, 14.3 Refs, 14B Refs [SPS-UCR-2015-003]	Incorporates Topical Report VEP-FRD-41, Rev. 02.
4.2.2.4, 9.1.2.6.9, 9.1.2.6.12, 9.1.2.6.13 [SPS-UCR-2015-004]	Reflects removal of the RCP Floating Ring Seal.
Table 5.4-17, Table 6.2-12, Figures 6.3-6 through 6.3-13, 8.5 [SPS-UCR-2015-002]	Update reflects the revised Surry Recirculation Spray Pump NPSH.
18.2.9 [SPS-UCR-2014-024]	License Renewal - update clarifies the responsibilities for General Condition Monitoring.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 47—09/30/15 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.10.1, 9.10.4.14 [SPS-UCR-2014-010]	Update reflects Beyond Design Basis installation of spent fuel pool external make-up water source.
3.2.1, 3.5.2.6.2.1, 3.5 Refs [SPS-UCR-2014-019]	Update reflects Westinghouse revised clad corrosion model for ZIRLO and Optimized ZIRLO.
3.2.3.3, 3.2 Refs, Table 3.2-1, 3.3.2.3, 3.4.2.3, 3.4.3.2, 3.4 Refs, 4.2.9, 14.1, 14.1 Refs, 14.3.2.1, 14.3.2.3 [SPS-UCR-2014-021]	Update reflects discussion of the W-3 Alternate DNB correlations approved in Appendix D to DOM-NAF-2-P-A and increase to technical specification minimum temperature for criticality.
9.5.1 [SPS-UCR-2013-007]	Update reflects installation of wide range spent fuel pool instrumentation.
18.2.19, Table 18-1 [SPS-UCR-2014-012]	Update reflects that work control inspections for license renewal are required to be performed by a VT qualified individual.
5.5.3, 5.5.4, 5.5.6, 5.5.7 [SPS-UCR-2014-017]	Update replaces reference to Regulatory Guide 1.163 with NEI 94-01, Revision 3-A.
Figure 9.12-1 [SPS-UCR-2014-018]	Updated figure for Fuel Transfer System.
18.2.16, 18.5 Refs [SPS-UCR-2014-020]	Modify reflects program name change from Secondary Piping and Component Inspection program to Flow Accelerated Corrosion program.

Revision 46—Updated Online 09/30/14

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 9.10-1 [SPS-UCR-2009-009]	Update corrects horsepower value for the replacement diesel-driven fire pump.
9.10.2.2.2, Table 9.10-1 [FS-2008-010]	Update reflects replacement of the diesel-driven fire pump.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 46—Updated Online 09/30/14 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.10.2.6, 9.10.4.5, 9.10.4.6 [SPS-UCR-2014-008]	Clarified description of the Appendix R equipment located in Normal Switchgear and Cable Tray Rooms.
9.10.2.2.2, 9.10.4.24, Table 9.10-1 [SPS-UCR-2014-011]	Update reflects replacement of the diesel-driven fire pump fuel tank.
3.5.2.3, 9.1.2.3.1, 9.1.2.3.2.5 [SPS-UCR-2014-009]	Update reflects the re-insertion of secondary source assemblies for Unit 2.
11.2.3, 11.3.2.10, 11.3 Refs [SPS-UCR-2014-006]	Radiation protection description updated to include the Steam Generator Storage Facility.
Table 14.5-6 [SPS-UCR-2014-007]	Table updated to reflect a post analysis of record evaluation performed to assess the effect of an error in the HOTSPOT burst strain model on peak cladding temperature for the large break loss of coolant accident.
5.1, Table 5.4-11, Table 5.4-12, Table 5.4-13, Table 5.4-17, Figure 5.4-3, Figure 5.4-4, Figure 5.4-5, Table 6.2-4, Table 6.2-13, Figure 6.3-6, Figure 6.3-10 [SPS-UCR-2014-004]	Update implements revised LOCA containment safety analysis.
9.10.2.2.1 [SPS-UCR-2014-002]	Updated the Fire Protection System description to reflect backup water supply.
10.3.5.2 [SPS-UCR-2014-005]	Updated the Condensate System description to reflect use as backup water for the Fire Protection System in an emergency.
4.1.7.3, 4.1 Refs [SPS-UCR-2013-017]	Update reflects the Westinghouse documents related to MUR Uprate Fluence Evaluations.
Table 9.7-1 [SPS-UCR-2012-003]	Update reflects replacement of the last (4 of 4) containment sump pump.
Figure 8.3-1 [SPS-UCR-2013-013]	Update reflects final configuration of 34.5 kV switchyard modifications.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 46—Updated Online 09/30/14 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 14.5-6 [SPS-UCR-2013-011]	Update reflects post analysis of record evaluation performed to assess the effects of revised heat transfer coefficient multiplier distributions on peak cladding temperature for the large break loss of coolant accident.
9.10.2.1 [FS-2007-007]	Update reflects Fire Detection System replacement - final configuration.
14.5.1.6, 14.5.3.2, 14.5, 15A.3.3, 15.A.6, 15A, Table 15A-5, Table 15A-6, Table 15A-7, Table 15A-8, Table 15A-9 [SPS-UCR-2013-009]	Update reflects the updated reactor vessel lower radial key stiffness value.
3.5.2.1, 3.5.2.1.4, 3.5, Figure 3.5-10 [SPS-UCR-2013-010]	Update reflects incorporation of the Robust Protective Grid and modified Debris Filter Bottom Nozzle to the 15 x 15 upgrade fuel assemblies.
15.5.1.11.2 [SPS-UCR-2013-015]	Modify corrected the tornado missile velocity requirement.

Revision 45—09/30/13

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
14.3.3.2.3.1, 14.3.3.2.3.2, 14.3.3.2.3.3, 14.3.3.2.3.4, Table 14.3-6, Figure 14.3-25, Figure 14.3-27 [SPS-UCR-2013-008]	Reflects implementation of a revised rod ejection analysis (ETE-NAF-2013-0052, Rev. 0).
9.10.4.12 [SPS-UCR-2013-004]	Update reflects removal of the stator cooler oil collection trays from the reactor coolant pump oil collection system.
Table 9.7-1 [SPS-UCR-2013-001]	Update reflects replacement of 3 of 4 containment sump pumps.
9.8.1, 9.8.2, 9.8.3, Table 9.8-1, Figure 9.8-1, 9.10.1 [SPS-UCR-2013-002]	Update reflects interim configuration of the compressed air system upgrade.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 45—09/30/13 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 4.1-5, 9.1.2.1 [SPS-UCR-2011-026]	Update reflects all reactor coolant pumps now using Flowserve N-9000 seal.
10.3.1.4, 10.3.5.2, Figure 10.3-8 [SPS-UCR-2013-005]	Condensate System description updated to reflect installation of Unit 2 air in-leakage subsystem.
11.3.3, 11.3.3.14 [SPS-UCR-2011-009]	Updated description for new monitors on main steam lines and turbine driven auxiliary feedwater pump.
7.2.2.1.1, 8.2 [SPS-UCR-2011-019]	Station service transformers description updated to reflect replacement cables.
18.2.7 [SPS-UCR-2011-020]	License renewal section updated to correctly identify damper housings inspection requirements.
18.2.9, 18.2.19 [SPS-UCR-2011-032]	License renewal section updated to clarify commitments associated with general condition monitoring and work control process.
18.1.2, Table 18-1 [SPS-UCR-2012-006]	License renewal section updated to indicate commitment 9 is now complete.
18.2.15, Table 18-1 [SPS-UCR-2012-007]	License renewal section updated to indicate commitment 14 is now complete.
Figure 9.9-1 [SPS-UCR-2012-013]	Service Water System figure updated to reflect Unit 1 flash evaporation demineralizer assembly demolition.
2.5.3.1, Table 2.5-2 [SPS-UCR-2012-012]	Additional information clarifies earthquake history is based on a specific timeframe.
Table 14.5-6 [SPS-UCR-2012-005]	Table updated to reflect post analysis of record evaluation performed to assess the effects of fuel thermal conductivity degradation on peak cladding temperature for the large break loss of coolant accident.
Figure 3.5-9 [SPS-UCR-2012-010]	Figure modified to add fuel type descriptor that was previously omitted.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 44—09/27/12

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.10.2.1 [SPS-UCR-2012-008]	Fire Detection System updated to reflect replacement of some of the Robertshaw panels with SimplexGrinnell panels.
Table 9.5-3 [SPS-UCR-2010-028]	Table updated to reflect alternate power sources for the spent fuel pool pump motor.
10.3.1.2 [SPS-UCR-2012-001]	Steam generator blowdown discussion updated to reflect rerouting of piping.
Table 9.13-1 [SPS-UCR-2011-029]	Main control room and emergency switchgear and relay room ventilation data updated to reflect minimum air flow required to maintain design ambient conditions following a bounding event.
18.2.15 [SPS-UCR-2011-031]	License Renewal commitment on reactor vessel internals guide cards updated.
14.5.1.7, Table 14.5-5, Table 14.5-6 [SPS-UCR-2012-002]	Best estimate large break loss of coolant accident analysis description updated to reflect change to containment heat sink surface areas.
10.3.5.2, Figure 10.3-9 [SPS-UCR-2009-001]	Update reflects installation of the ultrasonic flowmeters in the feedwater lines.
9.1.2.6.5 [SPS-UCR-2010-024]	Deborating demineralizer discussion updated to reflect use of deborating vessel as cation demineralizer.
14.2.9.2.4.2, Table 14.2-2, Table 14.2-4, 14.4.1.2.1, 14.4.1.2.2, 14.4.1.3.1, 14.4.1.3.2, 14.4, Table 14.4-1, Table 14.4-2, Table 14.4-5 [SPS-UCR-2011-008]	Updated design basis accident radiological analyses for the fuel handling accident and locked rotor analysis.
11.1 [SPS-UCR-2011-023]	Updated radiation protection description to reflect an upgrade to the Station’s self contained breathing apparatus.
10.3.5.2 [SPS-UCR-2010-026]	Auxiliary feedwater discussion updated for use of Carbohydrazide for startup of Unit 1.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 44—09/27/12 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
10.3.5.2 [SPS-UCR-2011-006]	Auxiliary feedwater discussion updated for use of Carbohydrazide for startup.
18.1.3, Table 18-1 [SPS-UCR-2011-014]	License Renewal commitment on tank inspections updated.
18.1.4 [SPS-UCR-2011-028]	License Renewal commitment on non-EQ cable inspections updated.
18.2.19 [SPS-UCR-2011-030]	License Renewal completion of work control audit commitment updated.
1.2.7, Figure 10.2-3, Figure 10.2-4, 10.3.3.1, 10.3 Refs, Figure 10.3-1, 14.2.13, 14.2.13.1, 14.2.13.2, 14.2.13.3, 14.2 Refs, Figure 14.2-72, Figure 14.2-73, Figure 14.2-74, Figure 14.2-75, Figure 14.2-76, Figure 14.2-77, Figure 14.2-78 [SPS-UCR-2009-017]	Updated descriptions and associated analyses to reflect Unit 1 turbine retrofit.

Revision 43—09/29/11

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
4.1.7.1, 4.1 Refs, Table 4.1-14, Table 4.1-15, 4.2.5, 4.3.3.2, 4.3.4, 4.3 Refs, Table 4.3-3, Table 4.3-4 [SPS-UCR-2010-007]	Update reflects increase to the cumulative core burnup applicability limit (effective full power years) for reactor coolant system pressure/temperature limits, low temperature overpressure protection system setpoints and low temperature overpressure protection system enabling temperature, to 48 effective full power years.
Table 3.2-1 [SPS-UCR-2011-025]	Modification reflects correction of departure from nucleate boiling ratio limit type on DNBR Limits Table.
6.2.2.2.4 [SPS-UCR-2010-017]	Update reflects current listing of motor operated valves that incorporate a pressure locking modification.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 43—09/29/11 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
18.1.2, 18.2.6, Table 18-1 [SPS-UCR-2011-010]	License Renewal completion of concrete aging commitment updated.
18.3.5.3, Table 18-1 [SPS-UCR-2011-011]	License Renewal implementation of Alloy Management Program commitment updated.
18.2.7, Table 18-1 [SPS-UCR-2011-012]	License Renewal completion of fire protection piping aging effects commitment updated.
18.2.19 [SPS-UCR-2011-016]	License Renewal Work Control Process audits commitment updated.
18.2.7, Table 18-1 [SPS-UCR-2011-017]	License Renewal completion of fire protection sprinkler commitment updated.
18.3.2.4 [SPS-UCR-2011-021]	License Renewal added dates the inspection of the pressurizer surge lines was completed.
Table 18-1 [SPS-UCR-2011-022]	License Renewal completion of worker qualification commitment updated.
6.2.2.2.3, 9.1.2.6.21 [SPS-UCR-2010-015]	Globe valve description updated.
9.10.4.12 [SPS-UCR-2010-031]	Fire protection description updated to reflect addition of an oil collection assembly on each reactor coolant pump stator cooler.
8.2, 10.3.3.2, Table 10.3-4, Figure 10.3-11 [SPS-UCR-2010-032]	Update reflects upgrading the isolated phase bus duct for both Units.
3.5.2.2 [SPS-UCR-2010-014]	Updated section to reflect a replacement batch of enhanced performance control rod assemblies will be placed in service for cycle 24 operation.
4.1.7.1, 4.1 Refs, Table 4.1-12, Table 4.1-13 [SPS-UCR-2011-007]	Updated the reactor vessel surveillance capsule withdrawal schedule for 60-year operation.
2.3.1.2.2 [SPS-UCR-2010-008]	Updated emergency service water pump house discussion to reflect addition of missile shield.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 43—09/29/11 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9C.2 [SPS-UCR-2011-003]	Appendix on flooding updated to reflect the high level stop log roller removal.
14.2.9.2.4.3 [SPS-UCR-2011-005]	Modified locked rotor accident discussion to make it consistent with other sections.
1.1.5, 1.1.6, 3.2.2.1, 3.2.2.7, 3.2.3.3, 3.2 Refs, Table 3.2-1, Table 3.2-2, Table 3.2-3, 3.3.3.2.2, 3.4.1, 3.4.1.1.2, 3.4.1.1.4, 3.4.1.2, 3.4.1.3, 3.4.2, 3.4.2.1, 3.4.2.2, 3.4.2.3, 3.4.3.1, 3.4.3.2, 3.4.3.3, 3.4.3.4, 3.4.3.5, 3.4.3.6 (new), 3.4 Refs, Table 3.4-1, 3.5, 3.5.2.1, 3.5.2.1.2, 3.5.2.1.3, 3.5.2.1.4, 3.5.2.1.5, 3.5.2.6.1, 3.5 Refs, Table 3.5-3, Figure 3.5-9, Figure 3.5-17 (new), Table 4.3-1, Table 4.3-2, 9.1.2.3.2.1, 9.1.3.6, 9.1 Refs, 14.1, 14.1 Refs, 14.2.1.1, 14.2.1.2, 14.2.2.1, 14.2.2.2, 14.2.4.1, 14.2.7.2, 14.2.7.3.2, 14.2.7.4, 14.2.8.1, 14.2.9.1.1, 14.2.9.1.2, 14.2.9.1.7, 14.2.9.2.1, 14.2.9.2.2.2, 14.2.10.2, 14.2.10.3, 14.2 Refs, 14.3.2.1, 14.3.2.3, 14.3.3.2.1, 14.3 Refs, 14.4.1.1, 14.4 Refs, 14.5.1.5, 14.5.1.6, 14.5.1.7, 14.5.2.4.2, 14.5.2.5, 14.5.2.6, 14.5.3.4.1, 14.5.3.4.2, Table 14.5-1, Table 14.5-2, Table 14.5-3, Table 14.5-5, Table 14.5-6, Table 14.5-7, Table 14.5-13, Table 14.5-17, Table 14.5-18 (new), Figure 14.5-1, Figure 14.5-2, Figure 14.5-3, Figure 14.5-4, Figure 14.5-5, Figure 14.5-6, Figure 14.5-7, Figure 14.5-8, Figure 14.5-9, Figure 14.5-10, Figure 14.5-11, Figure 14.5-12, Figure 14.5-13, Figure 14.5-14, Figure 14.5-76, 15A.5, 15A.5.2.5, 15A.6 (new), 15A Refs, Table 15A-8 (new), Table 15A-9 (new) [SPS-UCR-2009-023]	Updated descriptions and associated analyses to reflect implementation of the Westinghouse 15 x 15 upgrade fuel design.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 43—09/29/11 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.2.7, Figure 10.2-1, 10.3.1.1, 10.3.3.1, 10.3 Refs, Figure 10.3-1, 14.2.13.1 (new), 14.2.13.2, 14.2.13.3, 14.2 Refs, Figure 14.2-81, Figure 14.2-82, Figure 14.2-83 (new), Figure 14.2-84 (new), Figure 14.2-85 (new), Figure 14.2-86 (new), Figure 14.2-87 (new) [SPS-UCR-2009-012]	Updated descriptions and associated analyses to reflect Unit 1 turbine retrofit.
1.1.6, 3.5 Refs [SPS-UCR-2011-004]	Discussion corrected to state that mid-grids are made of ZIRLO and NOT Optimized ZIRLO.
Table 9.7-1 [SPS-UCR-2009-024]	Updated pump data for Unit 1 containment sump pump replacements.
Table 4.1-5, 9.1.2.1 [SPS-UCR-2010-012]	Revised description of reactor coolant pump seal leakoff to reflect Flowserve N-9000 seals.
8.2, 10.3.3.2, Table 10.3-4, Figure 10.3-11 [SPS-UCR-2010-013]	Revised discussion on isolated phase bus duct coolers to reflect Unit 1 upgrade.
9.10.4.12 [SPS-UCR-2011-002]	Updated discussion to reflect addition of reactor coolant pump stator cooler outlet trough oil collection assemblies.
Table 18-1 [SPS-UCR-2010-018]	Updated license renewal commitment related to alloy 82/182 weld material.
18.2.15, 18.5 Refs [SPS-UCR-2010-022]	Updated license renewal commitment to perform enhanced inspections of reactor vessel internals in accordance with EPRI MRP-227.
3.5.2.2 [SPS-UCR-2010-025]	Reflects replacement of enhanced performance control rod assemblies for Unit 1 cycle 24 operation.
9.10.4.8, 9.10 Refs, 9.13.3.1 [SPS-UCR-2010-033]	Removed requirement to use 1-VS-F-58B after an Appendix R fire to ventilate the charging pump cubicles.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 43—09/29/11 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.1, 1.1.2, 1.1 Refs, 3.2.1, 3.3.3.2.2, 3.4.1.3, Table 3.4-1, 4.1.7.1, 4.1.7.3, 4.1.7.4, 4.1 Refs, Table 4.1-2, Table 4.1-4, Table 4.1-5, Table 4.1-8, Table 4.1-14, Table 4.1-15, 4.2.5, 4.3.3.2, 4.3.4, 4.3 Refs, 5.3.1.1, 5.4.1.2, 5.4.3.1, 5.4.3.2.2, Table 5.4-1, Table 5.4-17, 6.2.1.1, 7.2.2.5, 7.3.2.6.1, 8.1, 9.1.2.2, 9.1.2.3.2.6, Table 9.1-4, Table 9.1-5, Table 9.1-6, Table 9.1-7, 9.4, 9.5, 9.9, 9.13.3.6, Figures 10.2-1 thru Figure 10.2-4, 10.3.1, 10.3.1.1, 10.3.1.2, 10.3.2, 10.3.3, 10.3.4, 10.3.5,10.3.5.2, 10.3.5.3, 10.3.9, Table 10.3-4, 11.2.5.1, Table 11.2-2, Table 11.2-3, 11.3.2.2, Table 11.3-3, Table 11A-1, 14.1, 14.1 Refs, 14.2.1.1, 14.2.1.2, 14.2.2, 14.2.2.1, 14.2.2.3, 14.2.4.1, 14.2.4.2, 14.2.4.3, 14.2.7.1, 14.2.7.2, 14.2.7.3.1, 14.2.7.3.2, 14.2.8, 14.2.8.1, 14.2.8.2, 14.2.8.3, 14.2.9.1, 14.2.9.1.1, 14.2.9.1.2, 14.2.9.1.6, 14.2.9.2.2.1, 14.2.9.2.2.2, 14.2.9.2.4.1, 14.2.9.2.4.3, 14.2.10.2, 14.2.10.3, 14.2.10.4.2, 14.2.10.5, 14.2.11.1, 14.2 Refs, Table 14.2-1, Table 14.2-2, Table 14.2-3, Table 14.2-4, Figure 14.2-1, Figure 14.2-2, Figure 14.2-3, Figure 14.2-4a, Figures 14.2-5 thru Figure 14.2-14, Figure 14.2-16, Figure 14.2-21, Figure 14.2-23, Figures 14.2-27 thru Figure 14.2-42, Figure 14.2-45, Figure 14.2-49, Figure 14.2-50, Figure 14.2-51, Figure 14.2-55, Figure 14.2-56, Figure 14.2-62, Figure 14.2-67, [SPS-UCR-2009-022]	Reflects the Measurement Uncertainty Recapture Power Uprate.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 43—09/29/11 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Figure 14.2-68, 14.3.1.2, 14.3.1.3, 14.3.1.4.3, 14.3.1.4.4, 14.3.2.1, 14.3.2.3, 14.3.2.4.2, 14.3.2.4.4, 14.3.2.5, 14.3.3.1.2, 14.3.3.2.2, 14.3.3.2.2.5, Tables 14.3-4 thru 14.3-11, Table 14.3-13, Table 14.3-15, Table 14.3-16, Figures 14.3-1 thru 14.3-9, Figure 14.3-14, Figure 14.3-19, Figure 14.3-24, Figure 14.3-26, 14.4.1.3.1, 14.4.2.1, Table 14.4-6, 14.5.2.3, 14.5.5, Table 14.5-1, Table 14.5-13, Appendix 14A, Table 14A-1, Table 14A-2 [SPS-UCR-2009-022]	(continued)
14.3.1.4.4, 14.3.2.4.4 [SPS-UCR-2010-030]	Removed discussion of 20 gpd primary to secondary leakage limit for Unit 1 B steam generator.
Table 9.7-1 [SPS-UCR-2010-034]	Updated pump data for Unit 2 containment sump pump replacements.
10.3.5.2, Figure 10.3-9 [SPS-UCR-2009-014]	Update reflects installation of the ultrasonic flowmeters in the feedwater lines.
10.3.1.2 [SPS-UCR-2010-020]	Description of the feedwater flow distribution removed to reflect new J-nozzle design, which provides even distribution.

Revision 42—09/30/10

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
14.2.9.1.6, Figure 14.2-49, Figure 14.2-50, Figure 14.2-55, Figure 14.2-56 [SPS-UCR-2010-019]	Loss of Reactor Coolant Flow Analysis updated to reflect the DNB transient for the underfrequency and undervoltage events in the LOFA reanalysis.
Table of Contents, List of Tables, List of Figures for following chapters: 9, 11, 14, & 15 [SPS-UCR-2010-021]	Table of Contents modified to include the Appendices Table of Content.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 42—09/30/10 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.10.1, 9.10.2.2.5, 9.10.4.19 [SPS-UCR-2009-027]	Fire Protection discussions updated to include the addition of the Turbine Deck Security Office.
15A.3.2, 15A Refs [SPS-UCR-2010-009]	Modified references to reflect procedures updated.
9.9.2 [SPS-UCR-2010-011]	Modified the total flow for each intake structure to be consistent with the circulating water pump flow rate.
7.7.2, 11.3.6 [SPS-UCR-2010-003]	Removed discussion of the Main Control Room Bottled Air System.
11.2.3.2 [FS-2003-045]	Final configuration reflects portions of the blowdown water treatment subsystem that are no longer used at the station.
9.10.2.1 [SPS-UCR-2010-002]	Interim configuration reflects portions of the Surry Fire Detection System that have been replaced.
11.2.3.2 [SPS-UCR-2010-005]	Corrects FS 2003-045 to reflect portions of the blowdown water treatment subsystem that is no longer in use.
2.1.5.2, 2.1 Refs [SPS-UCR-2010-006]	Adds a new reference to Chapter 2.
6.2.2.2.13, 6.3.1.2.5 [SPS-UCR-2009-003]	Description of the containment strainer assembly seals was updated to reflect installation of the U2 seal closure frames.
7.2.1.1, Table 7.5-2, 7.7.2, 9.10.4.17, 9.13.2, 9.13.3.6, 9.13.4.1, 9.13.4.2, Table 9.13-1, 14.2.9.2.4.3, 14.3.1.4.4, 14.3.2.4.4, 14.4.1.2.1, 14.4.1.3.1, 14.5.5.2 [SPS-UCR-2009-026]	Discussion of the Main Control Room Bottled Air System was removed.
10.3.5.2 [SPS-UCR-2009-028]	A discussion was added describing the use of Carbohydrazide for startup of Unit 2 using Auxiliary Feedwater.
9.1, 9.1.2.6.23, Figure 9.1-1 [FS 2007-014]	Reflects installation of Zinc Injection System for Unit 1.
9.1, 9.1.2.6.23, Figure 9.1-1 [FS 2008-023]	Reflects final configuration of Zinc Injection System.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 42—09/30/10 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
4.1.7.1, 4.1.7.3, Table 4.1-13 [SPS-UCR-2009-021]	Clarifies the capsule locations were original locations. Annotates Table to reflect relocation of Surry Unit 2 surveillance capsule U.
Table 9.7-1 [SPS-UCR-2009-025]	Corrected the containment sump pump data to reflect the current pumps.
18.3.5.6 [SPS-UCR-2009-011]	Updated discussion on reactor coolant pump and ASME code case N-481.
4.2.2.4, Table 4.1-5, 9.1.2.1 [SPS-UCR-2009-019]	Revised description of reactor coolant pump seal arrangement to reflect the Flowserve N-9000 seal.
14.5.2.1, 14.5.2.3, 14.5.2.4.1, 14.5.2.4.2, 14.5.2.5, 14.2.5.6, 14.5 Refs, Table 14.5-13, Table 14.5-14, Table 14.5-15, Table 14.5-16, Table 14.5-17, Figure 14.5-15 through Figure 14.5-76 [SPS-UCR-2009-008]	Revised to incorporate the reanalysis of the Westinghouse small break loss of coolant accident (SBLOCA).

Revision 41—09/30/09

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Figure 10.2-1 (sh 2), 10.3.3.2 [FS 2008-011]	Reflects the Unit 2 main generator change in hydrogen pressure.
10.3.5.2, 10.3.5.3 [FS 2007-020]	Clarified description of AFW system alignments to ensure minimum AFW flow requirements are met for design basis accident with the RCS above 350 degrees for both Units.
KWI [SPS-UCR-2009-020]	Removed key word index.
8.3, Figure 8.3-1 [SPS-UCR-2009-010]	Reflects the redirection of the 531 transmission line to Suffolk substation.
14.3.1.4.4, 14.3.2.4.4 [SPS-UCR-2009-013]	Reflects a 20 gpd leakage limit for Unit 1 B steam generator for operating cycle 23.
6.2.2.2.13, 6.3.1.2.5 [FS 2008-024]	Added a description of Unit 1 seal closure frames installed over the containment sump strainer flexible metal seals.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 41—09/30/09 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.4.3.5 [SPS-UCR-2009-005]	Raised the upper pH limit of the charging pump component cooling water system.
8.3, Figure 8.3-1, 8.5 [FS 2005-026]	Incorporates addition of Bus 7 and breakers in switchyard.
6.2.2.2.6, 6.2.4, 6.2.4.1.5, 6.2 Refs [SPS-UCR-2009-004]	Added new section, “Gas Accumulation in ECCS Piping” in response to Generic Letter 2008-01.
14.5.1.7, Table 14.5-5, Table 14.5-6 [SPS-UCR-2009-006]	Incorporates increase of carbon steel surface area in containment and the impact on the best estimate large break loss of coolant accident analysis.
9B.1.1, 9B.2.1, 9B.1 Refs, Table 9B.2-1 [FS 2008-021]	Updated the discussion on heavy loads to include reliance on a RV head drop analysis and revised the weight of the U1 RV head and lifting device.
5.4.2.1.7, Table 5.4-12, Table 5.4-13, Table 5.4-17, 6.1, 6.2.3.11, 6.3.1.3.2 [SPS-UCR-2009-002]	Implements changes to the Surry containment analysis using revised IRS/ORS pump flowrates.
9.4.3.3 [FS 2007-028]	Removed description of Chilled Water circulating pump low suction pressure trip.
5.4.2.1.7, Table 5.4-12, Table 5.4-13, Table 5.4-17, Figure 5.4-3, Figure 5.4-4, Figure 5.4-5, 6.3.1.4.3, 9.4.1.1, 9.4.3.3, 9.9.1 [FS 2008-017]	Incorporates increasing the SW inlet (river water) temperature to 100 degrees in accordance with Technical Specification change request 397.
14.5.1.6, 14.5.1.7, Table 14.5-1, Table 14.5-2, Table 14.5-3, Table 14.5-4, Table 14.5-5, Table 14.5-6, Figure 14.5-1, Figure 14.5-2, Figure 14.5-3, Figure 14.5-4, Figure 14.5-5, Figure 14.5-6, Figure 14.5-7, Figure 14.5-8, Figure 14.5-9, Figure 14.5-10, Figure 14.5-11, Figure 14.5-12, Figure 14.5-13, Figure 14.5-14 [FS 2008-022]	Incorporated the results of a reanalysis of the Westinghouse Best-Estimate Large Break Loss of Coolant Accident (BE-LOCA) analysis using the Automated Statistical Treatment of Uncertainty Method (ASTRUM).
18.5 Refs [FS 2008-025]	Editorial - Updated UFSAR references to reflect current revisions for the steam generator management program.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 41—09/30/09 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
6.2.2.1.3, 6.2.2.2.13, 6.2.3.11.1, 6.2.3.3, 6.2.4.1.4, 6.2 Refs, Table 6.2-3, 6.3.1.2.5, 6.3.1.3.1, 6.3.1.3.2, 6.3.1.3.3, 6.3.1.3.4, 6.3.1.4.1, 6.3.1.4.3, 6.3.1.4.4, 6.3 Refs Table 6.3-3 [FS 2007-011]	Updated various sections to reflect compliance with GSI-191 for the strainer assembly.
Table 4.1-1 [FS 2008-013]	Revised Low-Pressure trip setpoint to be consistent with TSCR 318.
3.5 Refs, 14.4 Refs [FS 2008-020]	Updated reference placeholders with standard reference information.
18.2.11, Table 18-1 [FS 2008-018]	Updated to reflect license renewal commitments that have been completed.
12.3, 12.3 Refs, KWI [FS 2008-019]	Added NEI 99-01 as a reference.

Revision 40—09/30/08

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
2.1.5.2, Table 2.1-4 [FS 2007-022]	Adds limitation on dimethylamine to chemical section.
9.10.2.2.7 [FS 2008-008]	Modifies description on the actuation of the Low Pressure CO_2 Fire Protection System dampers.
9.10.4.8, 9.10 Refs [FS 2008-009]	Reflects that forced ventilation of the charging pump cubicles is not required after an Appendix R fire.
8.3, Figure 8.3-1, 8.5 [FS 2008-014]	Reflects changes associated with partial implementation of modification to 34.5 kV switchyard buses 5 and 7.
8.4.1 [FS 2007-019]	Incorporates the disconnect of the auto start circuitry for the high pressure heater drain pumps.
6.3.1.3 [FS 2008-006]	Reflects the installation of the entire sump strainer for Unit 2.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 40—09/30/08 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
8.4.6 [FS 2008-012]	Incorporates changes associated with partial implementation of the modification of D transfer bus breaker to supply power to the TSC MCC and TSC UPS from the ACC diesel generator.
Table 9.4-1, Table 9.4-8 [FS 2008-007]	Corrected component cooling water pump design parameters.
5.4.1.2, 5.4.1.3.3, 5.4.1.3.5.4, 5.4.1.4, 5.4.2.1.6, 5.4.3, 5.4 Refs, Table 5.4-1, Table 5.4-2, Table 5.4-3, Table 5.4-4, Table 5.4-5, Table 5.4-6, Table 5.4-7, Table 5.4-8, Table 5.4-9, Table 5.4-13, Table 5.4-14, Table 5.4-15, Figure 5.4-1, Figure 5.4-2, Table 6.2-12, Table 6.2-13 [FS 2008-003]	Incorporates the containment response using new mass and energy data tables. Updates the minimum NPSH valves.
10.3.5.3 [FS 2007-024]	Updated the total accuracy value for the auxiliary feed flow loop.
10.3.5.2, 10.3.5.3 [FS 2008-001]	Incorporated changes associated with the modification of the operator selector switches for the AFW discharge MOVs.
9.10.4.23 [FS 2008-004]	Corrected the value of the concrete wall thickness separating the two fuel oil pump houses.
6.3.1.3, 11.3.2.1, Table 11.3-2, Figure 11.3-2 [FS 2006-024]	Modifies text associated with Incore Sump Room Drain Modifications.
3.5.2.6.1, 3.5 Refs, 14.4.1.1, 14.4 Refs [FS 2006-033]	Modifies lead rod average burnup limit for Surry fuel.
Figure 6.1-1, 6.2, 6.2.2.2.13, 6.2.3.11.3, Table 6.2-3,Table 6.2-13, 6.3, 6.3.1.2.5, 6.3.1.3, 6.3.1.4, Table 6.3-1, Table 6.3-3, Figure 6.3-2, Figure 6.3-5 [FS 2007-025]	Modifies text to reflect changes associated with Containment Sump Strainer Design.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 40—09/30/08 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.1.8, 1.4.49, 5.3.4.1, 5.3.4.3, 5.3 Refs, Table 5.3-5, 5.4, 5.4.1.1, 5.4.1.3.1, 5.4.1.3.2, 5.4.1.3.3, 5.4.1.3.4, 5.4.1.3.5.2, 5.4.1.3.5.3, 5.4.1.3.5.4, 5.4.1.3.5.5, 5.4.1.3.6, 5.4.1.4, 5.4.2, 5.4.2.1, 5.4.2.1.1, 5.4.2.1.2, 5.4.2.1.3, 5.4.2.1.4, 5.4.1.2.5, 5.4.2.1.6, 5.4.2.1.7, 5.4 Refs, Tables 5.4-6, 5.4-7, 5.4-8, 5.4-9, 5.4-10, 5.4-11, 5.4-12, 5.4-13, 5.4-14, 5.4-15, 5.4-16, 5.4-17, 5.4-18, 5.4-19, 5.4-20, 5.4-21, 5.4-22, 5.4-23, 5.4-24, & 5.4-25, Figures 5.4-1, 5.4-2, 5.4-3, 5.4-4, 5.4-5, 5.4-6, 5.4-7, 5.4-8, 5.4-9, 5.4-10, 5.4-11, 5.4-12, & 5.4-13, 6.2.2.1.4, 6.2.3.11.1, 6.2 Refs, Tables 6.2-11, 6.2-12, & 6.2-13, Figures 6.2-3, 6.2-4, 6.2-5, 6.2-6, & 6.2-7, 6.3.1.3, 6.3.1.4, Figures 6.3-7, 6.3-8, 6.3-9, 6.3-10, 6.3-11, 6.3-12, 6.3-13, 6.3-14, 6.3-15, 6.3-16, & 6.3-17, 14.5.4, 14.5.5, 14.5.5.2, 14.5.5.3, 14.5 Refs, Tables 14.5-7, 14.5-8, & 14.5-11, 14B.2.3.3.1, 14B.2.3.3.2.1, 15.5.1.2 [FS 2005-027]	Performed containment analyses and LOCA alternate source term analyses to support GSI 191 modifications Unit 1.
7.6.2.1 [FS 2006-035]	Removed information that specifies which flux thimble locations are plugged.
6.3.1.3, 7.5.1.3, Figure 7.5-2, Figure 7.5-3 [FS 2007-002]	Modified the refueling water storage tank engineered safety features actuation system to support GSI 191 containment sump modifications for Unit 1.
7.2, 7.2.1.8.6 [FS 2007-021]	Added replacement of the Westinghouse process modules with NUS Scientech modules.
1.1.8, 1.4.49, 14.5.4, 14.5.5, 14.5.5.2, 14.5.5.3, Table 14.5-8, Table 14.5-9, Table 14.5-12, 15.5.1.2 [FS 2008-002]	Editorial changes; clarifies final markups for GSI-191 multiple packages.
5.4.2.1.6, 5.4 Refs [FS 2007-023]	Revised text to describe an alternate containment analysis method that can be used for the calculation of NPSHa for the recirculation spray pumps, and containment pressure and sump temperature response.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 40—09/30/08 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
14.5.1.1, 14.5.1.2, 14.5.1.3, 14.5.1.4, 14.5.1.5, 14.5.1.6, 14.5.1.7, 14.5.2.5, 14.5 Refs, Tables 14.5-1, 14.5-2, 14.5-3, 14.5-4, 14.5-5, & 14.5-6, Figures 14.5-1, 14.5-2, 14.5-3, 14.5-4, 14.5-5, 14.5-6, 14.5-7, 14.5-8, 14.5-9, 14.5-10, 14.5-11, 14.5-12, 14.5-13, 14.5-14, 14.5-15, 14.5-16, 14.5-17, 14.5-18, 14.5-19, 14.5-20, 14.5-21, 14.5-22, 14.5-23, 14.5-24, 14.5-25, 14.5-26, 14.5-27, 14.5-28, 14.5-29, 14.5-30, 14.5-31, 14.5-32, 14.5-33, 14.5-34, 14.5-35, 14.5-36, & 14.5-37 [FS 2006-021]	Incorporated an analysis performed for LBLOCA using the Westinghouse Best-Estimate Large Break Loss of Coolant Accident (BE-LBLOCA) analysis methodology using the Automated Statistical Treatment of Uncertainty Method (ASTRUM). Revised text for consistency and removed unnecessary references.
14.5.1.6, 14.5.1.7, 14.5.2.5, Table 14.5-6 [FS 2007-026]	Revised table to incorporate a penalty to PCT for the analysis performed for the LBLOCA analysis using the Westinghouse BE-LBLOCA analysis methodology using ASTRUM.
4.3.4.2 [FS 2007-013]	Clarified the description of the pressurizer PORV backup air supply.
14.5.2.5, 14.5.2.6, 14.5 Refs, Table 14.5-15 [FS 2007-009]	Updated peak cladding temperature for small break LOCA analysis for Westinghouse fuel.
14.5 Refs, Table 14.5-5 [FS 2007-010]	Updated peak cladding temperature for large break LOCA analysis for Westinghouse fuel.
9.1, 9.1.2.6.23, Figure 9.1-1 [FS 2007-018]	Installed the Unit 2 zinc injection system.
14.2.9.2.4.2, 14.2.9.2.4.3, 14.3.1.4.4, 14.3.2.4.2, 14.3.2.4.4, 14.3 Refs, Tables 14.3-9, 14.3-10, & 14.3-15 [FS 2006-005 & FS 2006-020]	Revised the steam generator tube rupture and main steam line break accident analyses to reflect the change in the technical specification allowable primary-to-secondary leakage rate. [10 CFR 50.90 License Amendment]
18.2.11, 18.2.13, 18.2.15 [FS 2007-017]	Corrected the description of the Inservice Inspection Plan.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 39—09/27/07

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
KWI, 12.4 [FS 2007-016]	Reflected the audit and review functions contained in the Nuclear Facility Quality Assurance Program Description.
1.1.8, 1.4.49, 5.3.4.1, 5.3.4.3, 5.3 Refs, Table 5.3-5, 5.4, 5.4.1.1, 5.4.1.3.1, 5.4.1.3.2, 5.4.1.3.3, 5.4.1.3.4, 5.4.1.3.5.2, 5.4.1.3.5.3, 5.4.1.3.5.4, 5.4.1.3.5.5, 5.4.1.3.6, 5.4.1.4, 5.4.2, 5.4.2.1, 5.4.2.1.1, 5.4.2.1.2, 5.4.2.1.3, 5.4.2.1.4, 5.4.1.2.5, 5.4.2.1.6, 5.4.2.1.7, 5.4 Refs, Tables 5.4-6, 5.4-7, 5.4-8, 5.4-9, 5.4-10, 5.4-11, 5.4-12, 5.4-13, 5.4-14, 5.4-15, 5.4-16, 5.4-17, 5.4-18, 5.4-19, 5.4-20, 5.4-21, 5.4-22, 5.4-23, 5.4-24, & 5.4-25, Figures 5.4-1, 5.4-2, 5.4-3, 5.4-4, 5.4-5, 5.4-6, 5.4-7, 5.4-8, 5.4-9, 5.4-10, 5.4-11, 5.4-12, & 5.4-13, 6.2.2.1.4, 6.2.3.11.1, 6.2 Refs, Tables 6.2-11, 6.2-12, & 6.2-13, Figures 6.2-3, 6.2-4, 6.2-5, 6.2-6, & 6.2-7, 6.3.1.3, 6.3.1.4, Figures 6.3-7, 6.3-8, 6.3-9, 6.3-10, 6.3-11, 6.3-12, 6.3-13, 6.3-14, 6.3-15, 6.3-16, & 6.3-17, 14.5.4, 14.5.5, 14.5.5.2, 14.5.5.3, 14.5 Refs, Tables 14.5-7, 14.5-8, & 14.5-11, 14B.2.3.3.1, 14B.2.3.3.2.1, 15.5.1.2 [FS 2007-027]	Performed containment analyses and LOCA alternate source term analyses to support GSI 191 modifications Unit 2.
4.1.7.1, 4.1.7.3, 4.1.7.4, 4.1 Refs, Tables 4.1-14 & 4.1-15, 4.2.5, 4.3.3.2, 4.3 Refs, Tables 4.3-3 & 4.3-4 [FS 2006-015]	Incorporated the revised RT_{PTS} values provided for the Reactor Vessel Integrity Program. [10 CFR 50.61]
4.3.4.2 [FS 2006-022]	Changed the description of the pressurizer PORV backup air supply.
Figure 6.1-2, 6.2.2.2.13, 6.2.3.11.3, Tables 6.2-3 & 6.2-12, 6.3.1.2.5, 6.3.1.3, Tables 6.3-1 & 6.3-3, Figures 6.3-3 & 6.3-5 [FS 2006-029]	Completed partial installation of Unit 2 containment sump strainers to support GSI 191 modifications.
6.3.1.3, 6.3.1.4, 11.3.2.1, Table 11.3-2, Figure 11.3-3 [FS 2006-014]	Added the Unit 2 incore sump room drain to support GSI 191 containment sump modifications.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 39—09/27/07 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
6.3.1.3, Figure 6.3-17, 7.5.1.3, 7.5.2.1, Figures 7.5-2 & 7.5-3 [FS 2006-007]	Modified the Unit 2 refueling water storage tank engineered safety features actuation system to support GSI 191 containment sump modifications.
Figures 6.3-2 & 6.3-3 [FS 2006-012]	Modified the Unit 2 outside recirculation spray pumps' test loops.
7.3.2.4 [FS 2007-001]	Revised the description of pressurizer pressure control.
7.7.1, 7.9.1, 7.9.3, 8.2, 8.4.4, Figure 8.4-1, 9.10.2.1. [FS 2005-015]	Replaced the intake structure supervisory system in the low level intake structure and in the main control room.
7.7.2, 7.11.2, 8.4.3 [FS 2005-009]	Updated the description of the power supply for the remote monitoring panels.
9.1.2.1, 9.1.3.5.3, 9.6.3.1, 9.6.3.2, 9.10.3.3, 9C.2, 10.3.1.5, 11.3.4.2, 11.3.4.3, 11.3.4.4 [FS 2007-004]	Replaced "operable" terminology with "functional" terminology in accordance with Regulatory Issue Summary 2005-20.
Table 9.7-1 [FS 2006-034]	Updated the description of the component cooling heat exchanger pit sump pump shaft material.
9.10.4.18 [FS 2007-005]	Provided additional fire hazard analysis discussion in order to address Mechanical Equipment Room No. 4.
9.12.9, 9.12.9.1, 9.12.9.2, 9.12.9.3, 19.2 Refs, 9B.1.5 [FS 2007-003]	Revised the description of handling ISFSI cask systems.
9.14.2, Table 9.14-1 [FS 2005-024]	Added the dry shielded canister drain and reflood pumps.
Table 9.14-1 [FS 2004-017]	Replaced the spent fuel storage cask vacuum pumps.
10.3.1.1, 14.2.13 [FS 2006-032]	Modified the turbine overspeed protection control permissive logic and circuitry.
10.3.5.2, 10.3.5.3 [FS 2006-030]	Defeated the auto-open function for auxiliary feedwater flow isolation motor-operated valves.
Figure 10.3-10 [FS 2005-025]	Replaced chemical feed system pumps.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 39—09/27/07 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
11.2.6.2, 11.3.3, 11.3.3.1, 11.3.3.2, 11.3.3.13, 11.3.3.14, Tables 11.3-5, 11.3-6, & 11.3-8 [FS 2005-012]	Replaced ventilation system radiation monitors.
14.2.11.1, 14.2.11.1.1, 14.2.12, Figures 14.2-73, 14.2-74, 14.2-75, & 14.2-76 [FS 2006-031]	Revised the analysis description of auxiliary feedwater flow following loss of normal feedwater and loss of AC power events.
18.1.4, 18.2.6, 18.2.13, 18.2.19, Table 18-1 [FS 2006-025]	Reflected the completion of License Renewal Commitment Item Nos. 4, 12, 18, 26, and 27.
18.3.2.4, Table 18-1 [FS 2007-008]	Reflected the completion of License Renewal Commitment Item No. 24.

Revision 38—09/29/06

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
2.1.2.1 [FS 2006-023]	Revised the Exclusion Area Boundary to be the site boundary. [10 CFR 50.90]
2.2.1.2 [FS 2004-016]	Clarified the description of the applicability of Regulatory Guide 1.23 to meteorological equipment.
3.1, 3.1 Refs, 3.3.1, 3.3.2.3, 3.3.2.13, 3.3.3.2.2, 3.5.2.1.5, 3.5.2.5, 3.5.2.6.3, 3.5.2.6.4, Table 3.5-3, Figure 3.5-15, 3.6.3.13 [FS 2006-006]	Incorporated the use of integral fuel burnable absorber (IFBA) rods.
Figures 6.3-2 & 6.3-3 [FS 2006-004]	Modified the Unit 1 outside recirculation spray pumps' test loops.
7.6.2.1 [FS 2006-017]	Isolated the flux thimble tube at location 1-RC-TW-J3.
8.5 [FS 2004-023]	Modified the #1 and #3 emergency diesel generators' auto start circuits.
8.5 [FS 2006-009]	Aligned the description of engineered safeguards equipment powered by each emergency bus with the list contained in Technical Specification 3.16 Basis.
9.8 [FS 2006-016]	Corrected the description of the containment instrument air compressors' capacity.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 38—09/29/06 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9C.1.2 [FS 2005-013]	Augmented the description of the water level monitoring system to include the Amertap pit monitors and a description of the system power supply.
10.3.1.1 [FS 2005-008]	Clarified the description of the turbine-driven auxiliary feedwater pump design and operating conditions.
10.3.3.2 [FS 2005-022]	Added the new Unit 1 generator and exciter ratings and revised the cooling water flow value for the Unit 1 generator hydrogen coolers.
10.3.5.4 [FS 2006-010]	Revised the description of auxiliary feedwater pump surveillance test and inspections. [10 CFR 50.90]
11.2.3.1.7, 11.2.4.1.1, 11.2.4.1.5, 11.2.4.2.2 [FS 2005-016]	Corrected the description of Radwaste Facility reducing and processing functions.
14.3.3.2.1, 14.3.3.2.3.1, 14.3.3.2.3.2, 14.3.3.2.3.3, 14.3.3.2.3.4, 14.3 Refs, Table 14.3-6, Figures 14.3-24, 14.3-25, 14.3-26, and 14.3-27 [FS 2006-001]	Reanalyzed the control rod assembly ejection accident in support of the transition to Integral Fuel Burnable Poison (IFBA) fuel.
14.5.1.6, 14.5.2.5, 14.5.2.6, 14.5 Refs, Tables 14.5-5 & 14.5-15 [FS 2006-003]	Incorporated the peak clad temperature penalties and benefits for the large break and small break LOCA associated with implementation of IFBA fuel. [10 CFR 50.46]
14.5 Refs, Table 14.5-5 [FS 2005-007]	Incorporated the peak clad temperature penalties and benefits for the large break LOCA. [10 CFR 50.46]
14.5 Refs, Table 14.5-5 [FS 2006-002]	Incorporated the peak clad temperature penalties and benefits for the large break LOCA. [10 CFR 50.46]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 38—09/29/06 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Chapter 17 (all) [QA 2004-002]	Replaced Chapter 17 in its entirety with a brief description of and reference to the recently implemented Topical Report DOM-QA-1. The Dominion Nuclear Facility Quality Assurance Program Description is based on ANSI/ASME NQA-1-1994 and will be maintained as a separate, single document for Dominion facilities. [10 CFR 50.54(a)]
18.2.12 [FS 2005-023]	Removed the ASME XI edition and addenda reference for containment inservice inspection to allow periodic update as required by regulation.

Revision 37—09/30/05

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.1, 1.4.41, 2.1.3.5, 4.3.5, 5.1, 6.2.1.1, 6.2.2.1.3, 7.2.1.8.3, 14.1, 15.2.1 [FS 2004-031]	Corrected citations to regulation and regulatory guide dose limits for design basis accident analysis.
3.6.3.2 [FS 2004-029]	Indicated that ultrasonic or x-ray testing is no longer performed for burnable poison rods beginning with Cycle 20.
4.2.2.2, 4.2.6 [FS 2004-018]	Updated the estimated pressurizer heatup rate during startup for a reduced heater capacity of 1200 kW.
4.2.7.2, 7.5.2.2, 7.5.3.5, 7.6.2.2, 7.9.2 [FS 2004-027]	Replaced the emergency response facilities computer system.
4.3.3.1, 4.3 Refs [FS 2004-026]	Extended the inspection interval for reactor coolant pump flywheels from 10 to 20 years. [10 CFR 50.90]
Tables 4.3-2 & 4.3-4 [FS 2004-028]	Revised the stress intensity value for the Unit 2 reactor vessel flange.
4.4.1.7, 6.2.2.2.4, 6.2.2.2.10, 6.2.4, 6.3.1.5.1, 6.3.1.5.2, 9.3.4, 9.4.5 [FS 2004-033]	Changed the ASME Code reference for inservice testing activities from Section XI to a general reference to the ASME Code.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 37—09/30/05 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Tables 5.2-1 & 5.2-2 [FS 2005-011]	Reflected the removal of valves 1-MS-118 and 2-MS-118 as part of the decay heat subsystem removal.
5.3.5, 5.3 Refs, 6.2.3.3, 6.2.3.12.1, 6.2 Refs, Tables 6.2-14 & 6.2-15, Figures 6.2-3, 6.2-4, 6.2-5, 6.2-6, 6.2-7, & 6.2-8 [FS 2005-002]	Reflected that the Hydrogen analyzers and recombiners will continue to function and be periodically tested, but are no longer part of the plant design basis or credited in accident analyses.
6.3.1.3, Figure 6.3-16 [FS 2004-021]	Changed the refueling water storage tank low level alarm setpoint from 16.0% to 20.0%.
7.2.2.1.1 [FS 2000-006]	Increased the design temperature limit for power cable from 85°C to 90°C and described randomly spaced power cable having less than 1/4 diameter spacing.
7.2.3.2.7, Figure 8.4-1, 10.3.5.3 [FS 2003-030]	Changed electrical power feeds associated with replacement of the plant computer and the emergency response facilities computer system.
8.2 [FS 2003-060]	Provided clarification of the operating conditions and analysis required for electrical equipment and cables.
8.3, Figure 8.3-1 [FS 2004-006]	Installed redundant, underground feeder cables to the low level intake structure buses.
8.5 [FS 2003-037]	Corrected the description of the loads served by the emergency diesel generators. [10 CFR 50.90]
8.5 [FS 2004-025]	Clarified that three low head safety injection pump motors are analyzed to start at 72% of rated voltage.
8.5 [FS 2005-018]	Modified the #2 emergency diesel generator auto start circuit.
Table 9.4-2 [FS 2005-019]	Corrected the description of the capacity of the chilled water system chillers.
9.13.3.6, 9.13.4.2 [FS 2004-022]	Revised the description of the main control room and emergency switchgear and relay room ventilation system to rely on operating either one or two chillers.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 37—09/30/05 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9B.2.3, 9B.2.4.7, 9B.2 Refs, Table 9B.2-1 [FS 2004-038]	Replaced the 6-ton Auxiliary Building hoist with a 5-ton hoist.
10.3.5.2, Figure 10.3-9 [FS 2004-003]	Replaced Unit 2 auxiliary feedwater system isolation valves with stop-check valves.
10.3.5.2, Figure 10.3-9 [FS 2004-015]	Replaced Unit 1 auxiliary feedwater system isolation valves with stop-check valves.
Table 10.3-4 [FS 2004-004]	Revised the cooling water flow value for the Unit 2 generator hydrogen coolers.
Figure 10.3-11 [FS 2004-036]	Corrected tie-in locations between Sheets 1 & 2 describing the bearing cooling system.
Tables 11.3-5 & 11.3-7 [FS 2005-017]	Reflected consistent mark number format for the radiation monitoring system.
14.2 Refs, 14.3 Refs, 14B Refs [FS 2004-030]	Updated the references to the RETRAN Topical Report.
14.3.1.4.4, 14.3.2.4.2, Table 14.3-7, 14.3-8, 14.3-9, 14.3-10, 14.3-12, & 14.3-15 [FS 2005-010]	Corrected and clarified the description of the dose consequences of the main steam line break, locked rotor accident, and steam generator tube rupture based on the alternative source term methodology.
Table 14.3-8 [FS 2005-021]	Incorporated an editorial correction of the event time ranges.
14.5.1.6, 14.5 Refs, Table 14.5-5 [FS 2005-001]	Incorporated the peak clad temperature penalties and benefits for the large break LOCA. [10 CFR 50.46]
Figure 15.1-1 [FS 2004-032]	Provided the location of well-water supply system Well E and removed the incorrectly identified information center.
Figure 15.1-2 [FS 2004-010]	Added delay fencing in the Protected Area.
Figure 15.1-2 [FS 2004-012]	Added sally port fencing in the Protected Area.
15.6.2.1 [FS 2005-004]	Incorporated an editorial correction replacing “stem generator” with “steam generator.”
15.7, 15.7 Refs [FS 2004-034]	Clarified the scope of statistical information regarding the evaluation of masonry block walls in response to IE Bulletin 80-11.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 37—09/30/05 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
18.1.1, 18.1.4, 18.2.1, 18.2.9, 18.2.19, Table 18-1 [FS 2004-037]	Reflected the completion of License Renewal Commitment Item Nos. 1, 2, 3, 7, 8, 19, and 29.

Revision 36—09/30/04

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
KWI [FS 2004-002]	Updated the Key Word Index to incorporate an editorial correction.
3.3.3.2.1, 3.3 Refs, 3.5 Refs [FS 2003-035]	Updated references to the topical report for reload design methodology. [10 CFR 50.90 License Amendment]
3.5.3.1, 3.5.3.1.6, 4.1.2.8, 4.1.6, 4.1 Refs, Tables 4.1-2, 4.1-8, & 4.1-15, 4.2.2.1, Table 4.2-1, 4.3.1.1, Tables 4.3-2, 4.3-4, 4.4-1, & 9B.2-1, 14.3.3.1.1.1, 14.5.3, 14.5.3.3.4, 14.5 Refs, 15.2 Refs, Table 15.2-2 [FS 2003-040 & FS 2003-052]	Replaced the Unit 2 reactor vessel closure head.
Table 4.1-2 [FS 2003-051]	Identified the replacement reactor vessel heads' dome insulation thickness.
4.2.2.1, 5.3.1.3.2, 9.12.5.2, 9.12.5.4, 9B.2.5, Table 9B.2-1, Table 11.3-2, Figures 11.3-2 & 11.3-3, 14.3.3.1.1.4.2, 15.5.1.1, 15.5.1.8, 15.5.1.11.1, 15A.3.5.2, 15A.3.5.2.4, 15A Refs [FS 2003-048]	Upgraded the Unit 2 reactor head assembly.
4.2.7.2 [FS 2003-042]	Completed the installation of the Unit 2 N-16 primary-to-secondary leakage detection system.
4.3.1.1, Table 4.3-1 & 4.3-2 [FS 2004-008]	Provided a text description of cumulative usage factors for reactor vessel components in lieu of a tabular format. Updated stresses for reactor vessel components.
Table 5.3-2, 9.4.1.3, 9.4.3.3, Table 9.4-2, Figure 9.9-1, Table 10.3-4, Figure 10.3-11 [FS 99-065]	Updated the description of the Unit 2 chilled water system to reflect equipment replacement and changing the system's source of cooling water.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 36—09/30/04 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
5.5.3, 7.2.3.2.7, 7.3.2.3.2, 7.4.2.4, 7.4.3.2, 7.4.3.6, Tables 7.4-1, 7.4-2, & 7.4-3, 7.6.2.2, 7.7.2, Figure 7.7-1, 7.9.2, 7.9.2.2, 7.9.2.3, 7.9.2.5, 7.9.2.6, 7.9.3, 7.9.4, 9.10.4.1 [FS 2003-059]	Replaced the Unit 2 plant computer.
6.2.2.2.4 [FS 2003-053]	Replaced the Unit 2 charging pump discharge alternate header isolation valve, 2-CH-MOV-2287C.
7.2.1.2, 7.3.2.3.2, 14.2.4 [FS 2003-023]	Replaced the Unit 2 benchboard individual rod position indicators and the rod bottom lights with redundant flat panel displays.
7.5.2.2, 7.5.3.5, 7.6.2.2, 7.7.2, Figure 7.7-1, 7.9.2, 7.9.2.2, 7.9.2.5, 7.9.3 [FS 2002-019]	Replaced the Unit 1 plant computer.
7.6.2.1 [FS 2003-049]	Clarified the description of the Unit 2 incore instrumentation system.
8.5 [FS 2001-037]	Added provisions for inspection and repair of a buried fuel oil storage tank during plant operation. [10 CFR 50.90 License Amendment]
9.4.1.1 [FS 2004-014]	Added the vacuum priming system to the description of the component cooling heat exchangers.
9.4.1.3 [FS 2003-064]	Clarified the description of the chilled water used to cool the water in the refueling water storage tank.
9.4.1.3, Table 9.4-2 [FS 2003-050]	Updated the Unit 1 chilled water system capacity.
Table 9.6-1, 11.2.3.1.5, Table 11.2-1 [FS 2003-058]	Designated the waste disposal evaporator test tanks as “installed but no longer used.”
9.10.4.7 [FS 2004-011]	Removed the steam heating coils from the motor control center rooms’ ventilation units.
9.12.4.14, 9B.2.4.6, 9B.2.4.7, Table 9B.2-1 [FS 2003-011]	Uprated the Unit 2 polar crane capacity for each of the two hooks from 125 to 140 tons.
Figure 10.2-1, 10.3.3.2, Table 10.3-4 [FS 2003-012]	Replaced the Unit 2 main generator with an upgraded, refurbished generator.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 36—09/30/04 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
10.3.1.2 [FS 2003-039]	Restored the automatic control mode for the Unit 2 steam header pressure controller.
10.3.3.2, Table 10.3-4 [FS 2003-009]	Replaced the Unit 2 main generator exciter.
10.3.5.1 [FS 2003-041]	Increased the Unit 2 feedwater recirculation flow from 2800 to 4300 gpm.
10.3.5.2, Figure 10.3-9 [FS 2003-038]	Modified the Unit 2 feedwater bypass regulating valve line to provide bypass flow indication during unit startup.
10.3.5.3 [FS 2003-054]	Incorporated editorial correction of punctuation errors.
11.2.4.1.6 [FS 2003-029]	Added the low-level waste storage facility and sea van storage pad to the description of the solid waste disposal system.
14.2.9.2.2.2, 14.2.9.2.3, 14.2.9.2.4.1, 14.2.9.2.4.2, 14.2.9.2.4.3, 14.2.9.2.4.4, 14.2 Refs, Tables 14.2-2, 14.2-4, & 14.3-14 [FS 2003-044]	Reflected the reanalyzed dose consequences of a locked rotor accident using alternate source term and methodologies described in Regulatory Guide 1.183.
14.2.10.3, 14.2.10.4.2, Figures 14.2-68, 14.2-69, 14.2-70, 14.2-71, & 14.2-72 [FS 2004-007]	Updated the reanalyzed information and figures for loss of external electrical load/turbine trip.
14.3.1.4, 14.3.1.4.1, 14.3.1.4.2, 14.3.1.4.3, 14.3.1.4.4, 14.3.1.4.5, 14.3.2.4, 14.3.2.4.2, 14.3.2.4.3, 14.3.2.4.4, 14.3.2.4.5, 14.3 Refs, Tables 14.3-9, 14.3-10, 14.3-11, 14.3-12, 14.3-14, & 14.3-16 [FS 2003-057]	Incorporated the reanalysis of the dose consequences of the steam generator tube rupture and main steam line break using the alternative source term methodology.
14.4.1.2.1, 14.4.1.2.2, 14.4.1.3.1, 14.4.1.3.2, 14.4 Refs, Table 14.4-5 [FS 2003-055]	Incorporated the reanalysis of the dose consequences of a fuel handling accident using the alternative source term methodology.
14.5.2.4.2, 14.5.2.5 [FS 2004-024]	Made editorial corrections to correctly refer to Tables 14.5-15 & 14.5-16.
14.5.2.6, 14.5 Refs, Table 14.5-16 [FS 2004-019]	Incorporated a change to the summary of peak clad temperature penalties and benefits for the small break LOCA. [10 CFR 50.46]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 36—09/30/04 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
14.5.5.2, 14.5.5.3, 14.5 Refs, Table 14.5-12 [FS 2003-061]	Revised the discussion of dose consequences of the loss of coolant accident using 500 cfm instead of 10 cfm for the control room in-leakage and out-leakage parameters.
15.5.2, 15.5.2.1, 15.5.2.3, 15 Refs [FS 2003-031]	Completed the restoration of construction opening in the containment structure for the Unit 2 reactor pressure vessel head replacement.
17.2.1.2.D.3.c, Figure 17.2.1-3 [QA 2004-004]	Deleted the Manager Nuclear Engineering's responsibility for development of Improved Technical Specifications. Updated the title of and line of reporting for Supervisor Nuclear Records. [10 CFR 50.54(a)(3)]
17.2.2.8 [QA 2004-005]	Updated terminology to the current naming convention for inservice inspection personnel. [10 CFR 50.54(a)(3)]
17.2.10 [QA 2003-001]	Updated the description of qualification requirements for personnel performing non-destructive examinations. [10 CFR 50.54(a)(3)]
18.2.3 [FS 2004-001]	Established acceptance criteria for borated water leakage.
18.2.6, 18.2.10, Table 18-1 [FS 2004-005]	Described completion of commitments regarding inspection of inaccessible areas, groundwater monitoring, and internal inspections of containment polar crane girders.
18.2.19, Table 18-1 [FS 2004-009]	Described completion of commitments regarding procedures to assure consistent inspection of components for aging effects during work activities.
18.3.2.4, 18.5 Refs, Table 18-1 [FS 2003-062]	Completed detailed engineering evaluation for the potential effect of environmentally-assisted fatigue in safety injection accumulator nozzles and charging line nozzles.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 35—09/30/03

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.1, 1.6.2.3, 2.1.3.1, 3.1, 4.1, 4.1.4, 4.1.5, Tables 4.1-8, 4.1-12, & 4.1-13, 4.3.1.1, 4.3.1.2, Tables 4.3-3 & 4.3-4, 5.0, 6.1, 6.3.1.2.1, 7.1, 7.5.3.5, 8.0, 9.0, Table 9.1-3, 10.1, 11.1, 11.3.2.9.1, 15.5.1.8, 18.0, 18.1, 18.1.1, 18.1.2, 18.1.3, 18.1.4, 18.2, 18.2.1, 18.2.2, 18.2.3, 18.2.4, 18.2.5, 18.2.6, 18.2.7, 18.2.8, 18.2.9, 18.2.10, 18.2.11, 18.2.12, 18.2.13, 18.2.14, 18.2.15, 18.2.16, 18.2.17, 18.2.18, 18.2.19, 18.2.20, 18.3, 18.3.1, 18.3.1.1, 18.3.1.2, 18.3.1.3, 18.3.2, 18.3.2.1, 18.3.2.2, 18.3.2.3, 18.3.2.4, 18.3.3, 18.3.4, 18.3.5, 18.3.5.1, 18.3.5.2, 18.3.5.3, 18.3.5.4, 18.3.5.5, 18.3.5.6, 18.3.6, 18.4, 18.4.1, 18.4.2, 18.5, Table 18-1 [FS 2002-016]	Reflected the increased operating life basis from 40 to 60 years and added Chapter 18 [10 CFR 54.21] to describe the programs and activities that manage the effects of aging materials during the extended operation period associated with license renewal.
Table 2.1-4, Figure 15.1-2 [FS 99-064]	Installed a tank farm and feed system for treating the circulating water system with sodium bromide and sodium hypochlorite.
2.2.1.2, 3.3.2.13, 6.2.2.1.2, 7.4.3.3.3, 7.4.3.5.2, 7.4.3.7.2, 7.4.3.7.4, 7.4.3.7.5, 11.3.3, 11.3.4.1, 11.3.4.5 [FS 2001-044]	Replaced paper strip chart recorders in the control room with video display recorders.
3.5.2.6.1, 3.5 Refs [FS 2002-034]	Identified the references for the design requirements for fuel assembly structural components.
3.5.3.1, 4.1.2.8, 4.1.6, 4.1 Refs, Tables 4.1-2, 4.1-9, & 4.1-14, 4.2.2.1, 4.2.5, 4.2 Refs, Table 4.2-1, 4.3.1.1, Tables 4.3-1, 4.3-2, 4.3-3, & 4.3-4, 4.4.1.3, Table 4.4-1, 15A.5.2, 15A.5.2.1, 15.A.5.2.2, 15A.5.2.3, 15A.5.2.4, 15A.5.2.5, 15A Refs [FS 2003-018 & FS 2003-026]	Replaced the Unit 1 reactor vessel closure head.
4.1 Refs, Table 4.1-14 [FS 2003-001]	Reflected a new reference nil ductility transition temperature for the Unit 1 reactor vessel closure head dome. [10 CFR 50.55a(a)(3)(ii) and 10 CFR 50.55a(g)(6)(i) Relief Requests]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 35—09/30/03 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 4.1-1, 7.5.1.4.1, 7.5.1.4.2 [FS 2001-022]	Changed the reactor coolant system low-pressure alarm from 2205 to 2210 psig.
4.2.2.1, Figures 4.2-2 & 4.2-3, 9B.2.4.4, 9B.2 Refs, Table 9B.2-1 [FS 2003-019]	Modified the service structure, cooling air shroud and shroud support, radiation shield, insulation, and intermediate lift ring for the Unit 1 reactor vessel head replacement.
4.2.2.1, 4.3.1.1, Table 4.3-1 [FS 2002-031]	Enhanced the description of repairs performed on the Unit 1 reactor vessel head and control rod drive mechanism nozzles.
4.2.2.6 [FS 2002-029]	Clarified the description of flanges used in the reactor coolant system.
4.2.7.2 [FS 2001-035]	Installed the Unit 1 N-16 primary-to-secondary leakage detection system.
4.2.7.2 [FS 2003-043]	Installed the initial phase of the Unit 2 N-16 primary-to-secondary leakage detection system.
4.2 Refs, Table 4.3-3 & 4.3-4 [FS 2003-014]	Corrected typographical errors.
4.3.3.2, 4.3 Refs, Table 4.3-4 [FS 2003-007]	Reflected the revised RT_{PTS} values provided for the Unit 2 Reactor Vessel Integrity Program.
Table 6.2-5 [FS 2002-028]	Replaced charging pump 1-CH-P-1B.
6.3.1.5.1, 6.3.1.5.2 [FS 2002-002]	Revised the frequency of inspection for the containment spray and recirculation spray nozzles. [10 CFR 50.90 License Amendment]
Figure 6.3-1 [FS 2000-021]	Removed the vent caps from the refueling water storage tanks.
7.2.1.2, 7.3.2.3.2, 14.2.4 [FS 2003-005]	Replaced the Unit 1 benchboard individual rod position indicators and the rod bottom lights with redundant flat panel displays.
7.2.2.1.6 [FS 99-062]	Removed the reactor protection system logic channel testing event recorder.
7.2.2.5, Table 7.2-3, 7.8, 7.8.1, Figure 7.8-1 [FS 2002-022]	Removed the load frequency recorder and the automatic load control system.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 35—09/30/03 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
7.2.3.2.7, 7.9.4, 8.4.4, 8.4.5, 8.4.6, Figure 8.4-1, 9.10.2.7, 10.3.5.3 [FS 2002-017]	Provided power feed changes in preparation for plant computer replacement, installed a portion of the new computer for parallel testing, and permitted use of engineering-approved cable.
7.6.2.1, 7.6.3 [FS 2002-021]	Clarified the description of the incore instrumentation system.
8.4.4 [FS 2003-003]	Installed an additional 125V dc switchboard crosstie circuit breaker.
8.5 [FS 2003-013]	Modified the #3 emergency diesel generator breaker closure circuit.
9.4.3.5 [FS 2001-009]	Restored the original configuration of the charging pump component cooling water system.
9.10.2.2.2 [FS 2001-028]	Changed the pressure of the firewater system.
9.12.4.14, 9B.2.4.6, 9B.2.4.7, 9B.2 Refs, Table 9B.2-1 [FS 2003-010]	Uprated the Unit 1 polar crane capacity for each of the two hooks from 125 to 140 tons.
9.12.5.3 [FS 2003-017]	Provided an alternate method for monitoring subcriticality during fuel onload.
9.13.3.6 [FS 97-028]	Installed an alternate power feed to Mechanical Equipment Room-5 for use in the event of a fire.
9.13.3.6, 9.13.4.1 [FS 2000-019]	Provided shutdown of fans serving areas adjacent to the main control room (MCR) due to a safety injection signal or manual actuation in the MCR.
10.3.1.2 [FS 2003-028]	Restored the automatic control mode for the Unit 1 steam header pressure controller.
10.3.1.2, 10.3.8, 11.2.3, 11.2.3.2, 11.2.3.2.1, 11.2.3.2.2, Tables 11.2-4, 11.2-5, 11.2-6, & 11.2-7, Figures 11.2-2 & 11.2-3, 11.3.2.6, 11A.4, Tables 11A-10 & 11A-12 [FS 2003-047]	Reflected partial implementation of discontinued use of the steam generator blowdown treatment facility.
10.3.4.1, 10.3.4.2 [FS 98-045]	Increased the flow rate of the circulating water pumps from 210,000 gpm to 220,000 gpm.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 35—09/30/03 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
10.3.5.1 [FS 2003-004]	Increased the Unit 1 feedwater recirculation flow from 2800 to 4300 gpm.
10.3.5.2, Figure 10.3-9 [FS 2003-024]	Modified the Unit 1 feedwater bypass regulating valve line to provide bypass flow indication during unit startup.
10.3.9, 10.3.9.2, Figure 10.3-11 [FS 2001-003 & FS 2003-046]	Added description of the bearing cooling normal makeup water supply and treatment system.
Figure 10.3-7 [FS 2001-030A]	Installed an additional cross-connect valve for isolation of the Unit 1 auxiliary steam header.
Figure 10.3-11 [FS 2000-029]	Replaced turbine lube oil coolers' temperature control valves with manual throttle valves.
Figure 10.3-11 [FS 2001-006]	Removed and capped dead-leg piping to the flash evaporators that are abandoned in place.
14.2.1.1, 14.2.1.2 [FS 2003-032]	Corrected the description of the reactor trip setpoint for the rod withdrawal from subcritical event.
14.4.1.2.1 [FS 2003-006]	Updated a cross-reference number.
14.5.3.2, 14.5 Refs [FS 2003-002]	Added text describing that it has been shown that the control rods will insert for cold leg breaks.
14.5 Refs, Table 14.5-5 [FS 2003-027]	Incorporated a change to the summary of peak clad temperature penalties and benefits for the large break LOCA. [10 CFR 50.46]
15.3.1, 15.3.2, 15.4, 15.4.1, 15.4.2, 15.4.3, 15.5.1.6, 15.5.1.8, 15.5.1.9, 15.5.1.9.1, 15.5.1.9.3, 15.5.1.9.4, 15.5.1.10, 15.5.2, 15.5.2.1, 15.5.2.2, 15.5.2.3, 15.5.2.4, 15.5.2.5, 15.5 Refs [FS 2003-020 & FS 2003-025]	Completed the restoration of construction opening in the containment structure for the Unit 1 reactor pressure vessel head replacement.
17.2.0.2, Table 17.2-0, 17.2.2.1, 17.2.2.5, 17.2.2.6, 17.2.10, 17.2.17 [FS 2003-021]	Made editorial corrections to correctly refer to Table 17.2-0.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 35—09/30/03 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
17.2.1.1.A, 17.2.1.2.B, 17.2.1.2.B.1, 17.2.1.2.B.1.b.1.1, 17.2.1.2.C.1, 17.2.16.2.B.2, 17.2.16.2.C, 17.2.1.16.2.D, Figures 17.2.1-1 & 17.2.1-2, Table 17.2-0, App C A.8.e, B.6.e, B.6.i, B.7.c, & B.8 [FS 2003-015]	Revised organizational titles of the Senior Vice President Nuclear Operations, Shift Manager, and Unit Supervisor. [10 CFR 50.54(a)(3)]
17.2.1.2 [FS 2003-008]	Assigned responsibility for maintenance of plant equipment history to the Manager Nuclear Maintenance. [10 CFR 50.54(a)(3)]
17.2.1.2.A.2, Figure 17.2.1-1 [FS 2002-006]	Deleted the description of and reference to the Nuclear Oversight Board. [10 CFR 50.54(a)(4)]
Table 17.2-0 [FS 2002-033]	Provided for the repair and testing of a temporary opening in the containment due to reactor vessel head replacement. [10 CFR 50.54(a)(3)]

Revision 34—09/03/02

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.1.8, 1.4.11, 1.4.47, 2.1.2.1, Figure 2.1-3, 5.3.1.2, 5.3.1.3.4, 5.3.1.4, 5.3.1.4.1, 5.3.1.4.2, 5.4, 6.1, Table 6.2-6, 6.3.1.1, 7.7.1, 9.12.6, 9.12.6.1, 9.13.1, 9.13.2, 9.13.3.1, 9.13.3.2, 9.13.3.6, 9.13.3.7, 9.13.4.1, 11.3.1, 11.3.3.13, 11.3.4.2, 11.3.4.3, 11.3.4.4, 11.3.6, Table 11.3-1, 14.4.1.1, 14.4.1.2, 14.4.1.2.1, 14.4.1.2.2, 14.4.1.2.2.1, 14.4.1.2.2.2, 14.4.1.2.2.3, 14.4.1.2.2.4, 14.4.1.2.3, 14.4.1.3.1, 14.4.1.3.2, 14.4.1.3.3, 14.4.1.3.4, 14.4 Refs, Tables 14.4-1, 14.4-2, 14.4-3, 14.4-4, & 14.4-6, 14.5.4, 14.5.5, 14.5.5.1, 14.5.5.2, 14.5.5.3, 14.5.6, 14.5 Refs, Tables 14.5-7, 14.5-8, 14.5-10, 14.5-11, & 14.5-12 [FS 2000-005A]	Incorporated the reanalysis of the LOCA and Fuel Handling Accidents resulting from the implementation of alternative source term. [10 CFR 50.67]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 34—09/03/02 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
3.4.1.1, 3.4.1.1.4, 3.4.1.2, 3.4 Refs, 3.5.2.1, 3.5.2.6.1, 3.5 Refs, Table 3.5-3 [FS 2002-003]	Reflected the physical description of Surry 2 Batch 20 and subsequent reload fuel batches for Units 1 and 2. Identified the fuel performance models for cycle-specific evaluations.
4.2.2.4 [FS 99-053]	Replaced reactor coolant pump main flange bolts with main flange fasteners.
4.3.1.1 [FS 2001-043]	Described the repairs performed on the Unit 1 reactor vessel head and control rod drive mechanism nozzles.
4.3.1.1, Figure 4.3-2 [FS 2001-046]	Clarified the stress analysis boundary conditions at the vessel head penetration shrink fit for the control rod drive mechanism housings. Showed the vessel head penetration welds in their correct orientation.
5.4.1.3.5.4, 8.4.4 [FS 2002-024]	Updated a reference document number and corrected a typographical error.
6.2.3.12.1, 6.2 Refs, Tables 6.2-14 & 6.2-15, Figures 6.2-3, 6.2-4, 6.2-5, 6.2-6, 6.2-7, & 6.2-8 [FS 2002-012]	Re-evaluated the hydrogen concentration in containment following a LOCA.
Table 6.2-13, 6.3.1.3, Table 14B-3 [FS 2001-026]	Changed the bleed flow contribution to outside recirculation spray pump NPSHa, clarified the function of the recirculation spray suction cross-connect line, and deleted the component cooling heat exchangers from the list of postulated targets in the auxiliary building.
7.6.2.1 [FS 2001-042]	Installed a plug in the high pressure seal at Unit 1 core location J5 (1-RC-TW-J5).
7.6.2.1, 7.6.2.2, 7.6.2.3.1, Figures 7.6-1 & 7.6-2 [FS 2000-049]	Provided the description of a second flux thimble tube and seal table seals design. Described the process for converting to the new design.
7.6.2.1, Figure 7.6-1 [FS 2002-013]	Installed a plug in the high pressure seal at Unit 2 core location N8 (2-RC-TW-N8).

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 34—09/03/02 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
7.7.2, 9.10.3.5, 9.10.4.13, 10.3.1.2 [FS 99-034]	Incorporated changes to reflect that the decay heat release subsystem is no longer used and that decay heat release components have been removed on Unit 1.
Figure 8.3-1, 8.4.4 [FS 2002-004]	Installed an additional 125V dc switchboard crosstie circuit breaker.
8.5 [FS 2001-001]	Removed the diesel generator voltage and speed relay from the residual voltage time delay relay circuit and increased the time delay from 2.0 to 2.2 seconds.
8.5 [FS 2002-020]	Clarified the description of the analysis consideration of a loss of offsite power being sequenced with a loss of coolant accident.
8.5, Table 8.5-1 [FS 99-025]	Updated the setting of the emergency bus degraded voltage relays. [10 CFR 50.90 License Amendment]
9.1.2.1 [FS 2001-036]	Clarified auxiliary spray valve operation meeting the requirements of the Appendix R analysis.
9.4.3.1 [FS 2002-008]	Clarified component cooling system thermal relief requirements.
9.6.1.2, 9.6.2.2, 9.6.2.2.1, 9.6.2.2.3, 9.6.2.2.6, 9.6.3.2, 9.6.4.2, 9.6 Refs, Tables 9.6-3 & 9.6-7 [FS 2002-011]	Clarified the status of the High Radiation Sampling System—Post-Accident Operation. [10 CFR 50.90 License Amendment]
9.6.2.1 [FS 2001-024]	Reflected the abandonment of recorders from the secondary sampling system on-line chemistry monitoring panels.
9.10.1 [FS 2001-039]	Identified fire protection systems that are not required to satisfy regulatory criterion. [10 CFR 50.48]
9.10.1, 16.2, 17.2.1.2, 17.2.5 [FS 2001-034]	Removed terminology associated with the former 10 CFR 50.59 regulation and incorporated wording from the current rule.
9.13.1, 9.13.4.1 [FS 2002-009]	Clarified the description of auxiliary building ventilation fan performance.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 34—09/03/02 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.13.3.3, 9.13.4.1 [FS 2002-015]	Enhanced the text description of the decontamination building ventilation system operation.
9B.2.4.4 [FS 2001-002]	Added the reactor vessel head stud racks to the description of special lifting devices.
9B.2.4.4, Table 9B.2-1 [FS 2001-017]	Removed the pneumatic reactor cavity seal ring and its lifting rig.
11.2.3, 11.2.3.1.7, 11.2.3.2, Tables 11.2-5 & 11.2-6 [FS 98-001]	Updated the description of steam generator blowdown to reflect system lineup and chemistry guidelines.
11.2.4.1.2 [FS 97-011]	Incorporated current methodology for handling and storing spent radioactive filters.
11.3.3.8, Tables 11.3-6 & 11.3-7 [FS 2001-025]	Changed the Unit 1 condenser air ejector radiation monitor to a more sensitive detector.
11.3.3.8, Tables 11.3-6 & 11.3-7 [FS 2001-038A]	Changed the Unit 2 condenser air ejector radiation monitor to a more sensitive detector.
14.2.10.3, 14.2.10.4, 14.2.10.4.1, 14.2.10.4.2, Figures 14.2-62, 14.2-63, 14.2-64, 14.2-65, 14.2-66, 14.2-67, 14.2-68, 14.2-69, 14.2-70, 14.2-71, & 14.2-62 [FS 2001-018]	Incorporated an improved analysis technique concerning loss of external electrical load.
Table 14.2-4 [FS 2001-031]	Cited the regulatory whole body dose limit. [10 CFR 100]
14.5 Refs, Table 14B-2, 15.5 Refs [FS 2001-041]	Corrected typographical errors.
14B.3.3, 14B.5.3.3 [FS 2001-045]	Provided discussion of the auxiliary building ambient temperature monitoring system for detection of a high energy line break and associated automatic/manual actions.
17.2.1.1, 17.2.1.2, 17.2.10, Figures 17.2.1-1, 17.2.1-2, & 17.2.1-3 [FS 2002-005]	Modified organizational titles and realigned certain reporting relationships within the Nuclear Business Unit. [10 CFR 50.54(a)(3)]
17.2.1.2, Figures 17.2.1-1 & 17.2.1-3 [FS 2001-040]	Relocated the Records Management Program organization from General Services to Nuclear Engineering. [10 CFR 50.54(a)(3)]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 34—09/03/02 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
17.2.1.2, 17.2.3, 17.2.5, 17.2.6, 17.2.11, 17.2.15, 17.2.16, 17.2.18, 17.2 Refs, Table 17.2-0, Appendix C [FS 2001-023]	Relocated North Anna Power Station current technical specification requirements for the Management Safety Review Committee, Station Nuclear Safety and Operating Committee, and Station Nuclear Safety to the QA Topical Report. [10 CFR 50.90 License Amendment]
17.2.7 [FS 2002-023]	Updated the description of the organizational structure to reflect the responsibilities of the Vice President Nuclear Engineering and Vice President Nuclear Support Services with respect to procurement, vendor surveillance, and document reviews. [10 CFR 50.54(a)(3)]

Revision 33—09/04/01

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.1.6, 1.2.3, 3.3.2.12, 3.5, 3.5.1.3, 3.5.2.1, 3.5.2.1.1, 3.5.2.1.2, 3.5.2.1.4, 3.5.2.1.5, 3.5.2.2, 3.5.2.3, 3.5.2.4, 3.5.2.5, 3.5.2.6.1, 3.5.2.6.3, 3.5.2.6.4, 3.5.3.1, 3.5.3.1.1, 3.5.3.1.2, 3.5.3.2.1, 3.5.4, 3.5.4.1, 3.5 Refs, Tables 3.5-1 & 3.5-3, Figures 3.5-3, 3.5-4, 3.5-5, 3.5-7, 3.5-9, 3.5-11, 3.5-12, & 3.5-13 [FS 2000-027]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of mechanical reactor design.
1.4.23, 7.5.1, 8.4.3 [FS 2001-011]	Provided clarification of the design and licensing basis for the power supplies to the vital bus systems.
2.4.1, Table 9.2-1, Table 15.2-1, 15.5.1.8 [FS 2000-051]	Corrected typographical, administrative, and format errors.
3.4.1.1.2, 3.4.1.1.3, 3.4.1.1.4, 3.4.1.1.5, 3.4.1.2, 3.4.1.3, 3.4.2, 3.4.2.1, 3.4.2.1.1, 3.4.2.1.2, 3.4.2.2, 3.4.2.2.1, 3.4.2.2.2, 3.4.2.2.3, 3.4.2.2.4, 3.4.2.3, 3.4.2.4, 3.4.2.5, 3.4.2.6, 3.4.3.1, 3.4.3.2, 3.4.3.2.1, 3.4.3.3, 3.4.3.5, 3.4.3.8, 3.4 Refs, Table 3.4-1, Figures 3.4-1, 3.4-4, 3.4-8, & 3.4-10, Table 4.2-1, 8.5, 10.3.5.3 [FS 2000-028]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of thermal/hydraulic reactor design.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 33—09/04/01 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
4.2.2.8, 14.2.6.2.2, 14.2.6.2.3 [FS 99-042A]	Established additional reactivity controls and surveillance for the vacuum-assisted backfill method of returning an RCS loop to service. [10 CFR 50.90 License Amendment]
Table 5.4-20 [FS 2001-013]	Revised the containment analysis results for depressurization time and subatmospheric peak pressure.
6.2.3.12.1, Table 6.2-14 [FS 2001-010]	Updated the description of the containment hydrogen generation analysis.
6.2.3.12.1, Table 6.2-14, 14.5.1.3, 14.5.1.4, Table 14.5-3, 15A References [FS 2001-027]	Corrected typographical, administrative, and format errors.
Figures 6.2-1 & 6.2-2 [FS 99-063]	Incorporated modifications to the Unit 1 safety injection system.
7.6.2.1, Figure 7.6-1 [FS 2000-046]	Installed a seal welded cap on the flux thimble tube at location 2-RC-TW-N8.
8.5 [FS 2000-037]	Added definition of loss of offsite power (LOOP) as a LOOP to both units to the introduction of the emergency power system.
8.5 [FS 2000-045]	Added a time delay relay to each filter exhaust fan start circuit to allow proper damper alignment.
9.4.4.3 [FS 2000-043]	Provided a description of the air lockup valve on the reactor coolant pump thermal barrier inside and outside containment component cooling trip valves.
9.6.1.2, 9.6.2.2.6, Table 9.6-7 [FS 2000-052]	Deleted time restraints for containment sump sampling or analysis with the high radiation sampling system.
9.8.1, Table 9.8-1 [FS 2001-007]	Deleted statement that the compressed air system air receivers are sized to provide ten minutes of breathing quality air and air to essential systems after shutdown of all compressors following a loss-of-power accident. Corrected compressed air system design data.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 33—09/04/01 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.10.4.4 [FS 2000-048]	Included a description of the two-hour design basis discharge/recharge case for the station batteries.
9.10.4.4 [FS 99-043]	Revised the description of hydrogen generation and fire potential in the station battery rooms.
9.10.4.12 [FS 2000-041]	Incorporated modifications to the reactor coolant pump motor oil collection system.
9.10.6, 12.2.2.3, 17.2.1.1, 17.2.1.2, 17.2.2.1, 17.2.2.5, 17.2.3, 17.2.7, 17.2.10, 17.2.15, 17.2.16.2, 17.2.17, 17.2.18, Figures 17.2.1-1, 17.2.1-2, & 17.2.1-3, Table 17.2-0 [FS 2001-019]	Modified organizational titles and reporting relationships associated with the entire Nuclear Business Unit. [10 CFR 50.54(a)(3)]
9.12.3.1, 9.12.5.2 [FS 2000-017]	Changed the design of the reactor cavity seal from pneumatic to mechanical.
9.12.5.2 [FS 2000-044]	Corrected the description of lifting the reactor vessel head with the reactor containment polar crane.
9.13.1, 9.13.4.1, 14.3.2 [FS 2000-024]	Updated the description of feedwater isolation for the rupture of a main steam pipe accident and of auxiliary building ventilation system capability.
9.13.2 [FS 99-046A]	Clarified the design and testing of the safety-related charcoal filters installed in the auxiliary ventilation exhaust system. [10 CFR 50.90 License Amendment]
9.13.3.7, 9.13.4.1 [FS2000-053A]	Clarified auxiliary filtration requirements consistent with the Basis for Technical Specification 3.22.
9C.1.1, 9C.2 [FS 97-020]	Deleted “carbon steel” from the description of the flow restriction shields installed around circulating water system expansion joints.
10.3.1.2, 14.3.1.5 [FS 99-057]	Added the description of the backup bottled air system for the steam generator power operated relief valves.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 33—09/04/01 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
11.2.3, 11.2.3.1.10, Table 11.2-1, Figures 11.2-2 & 11.2-5 [FS 2000-047]	Installed a cross-connect line between the Radwaste Facility building drain system and the laundry waste system. Installed a second laundry drain pre-filter.
Tables 11.2-2 & 11.2-3 [FS 2001-014]	Corrected typographical errors.
14.2.11.1, 14.2.12, Figures 14.2-73, 14.2-74, 14.2-75, 14.2-76, 14.2-77, 14.2-78, 14.2-79, & 14.2-80, 14B.5.1.7 [FS 2001-005]	Described the reanalysis of the loss of normal feedwater (LONF) and loss of ac power to the station auxiliaries (LOAC) events with 500 gpm auxiliary feedwater flow during the transient.
14.3.1.4.2, 14.3.1.4.4, 14.3.1.4.5, 14.3.2.4.2, 14.3.2.4.4, 14.3.2.4.5, 14.3 Refs, Tables 14.3-9, 14.3-10, 14.3-11, 14.3-12, & 14.3-16 [FS 2000-032]	Reflected the reanalysis of the dose consequences of the steam generator tube rupture and main steam line break events.
14.5.1.1, 14.5.1.2, 14.5.1.3, 14.5.1.4, 14.5.1.5, 14.5.1.7, 14.5.1.8, 14.5 Refs, Tables 14.5-2, 14.5-3, 14.5-4, 14.5-5, 14.5-6, 14.5-7, 14.5-8, & 14.5-9, Figures 14.5-2, 14.5-3, 14.5-4, 14.5-5, 14.5-6, 14.5-7, 14.5-8, 14.5-9, 14.5-10, 14.5-11, 14.5-12, 14.5-13, 14.5-14, 14.5-15, 14.5-16, 14.5-17, 14.5-18, 14.5-19, 14.5-20, 14.5-21, 14.5-22, 14.5-23, 14.5-24, 14.5-25, 14.5-26, 14.5-27, 14.5-28, 14.5-29, 14.5-30, 14.5-31, 14.5-32, 14.5-33, 14.5-34, 14.5-35, 14.5-36, 14.5-37 [FS 2001-008]	Updated the analysis of the large break loss-of-coolant accident.
Table 15.2-1 [FS 2000-054]	Restored the seismic Category I designation for the yard hydrant piping system.
15.5.1.8, 15.5 Refs. [FS 99-013]	Documented the evaluation of isolated containment penetration piping for susceptibility to thermal over-pressurization following a DBA. [NRC Generic Letter 96-06]
15A.3.2, 15A Refs [FS 2001-004]	Incorporated generic implementation procedure criteria and methodology for seismic verification of equipment.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 33—09/04/01 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
17.2.17, Table 17.2-0 [FS 99-067]	Updated the Quality Assurance Topical Report description of the retention of quality assurance records in electronic media. [10 CFR 50.54(a)(4)]
Table 17.2-0 [FS 2001-020]	Clarified the provision for substitution of experience for a bachelor's degree. [10 CFR 50.54(a)(3)]
Tables 17.2-0, 17.2-2, & 17.2-3 [FS 2000-003]	Reduced records retention requirements consistent with ANSI N45.2.9 or applicable regulations. [10 CFR 50.54(a)(4)]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
KWI, 1.4.2, 1.4.5, Ch 2, 2.2.2.1, 2.3.1.2.2, Tbl 2.3-7, 2.4.7.2, 2.4.7.6, 2.4.9, Tbls 2.4-9, 2.4-10, & 2.4-12, Figs 2.4-5 & 2.4-6, 2.5.4.3, 4.3.1.2, 4.3 Refs, Tbl 4.3-3, Fig 4.3-3, 7.2.1, 7.5.1, 9.2.3.1, 9A.2, 9A.3.1.3.1, 15.1, 15.2.4, Tbl 15.2-1, 15.4.1, 15.4.4, 15.4.5, 15.4.6, 15.4.6.1, 16.4.6.2, 15.4.6.3, 15.4.6.4, 15.4.6.4.1, 15.4.6.4.2, 15.4.6.4.3, 15.4.6.4.4, 15.4.6.4.5, 15.4.6.4.6, 15.4.6.4.7, 15.4.6.4.8, 15.4.6.4.9, 15.4.6.4.10, 15.4.6.4.11, 15.4.6.4.12, 15.4.6.4.13, 15.4.6.4.14, 15.4.6.4.15, 15.4.6.4.16, 15.4.6.4.17, 15.4.6.4.18, 15.4.6.4.19, 15.4.6.5, 15.4.6.5.1, 15.4.6.5.2, 15.4.6.5.3, 15.4.6.5.4, 15.4.6.5.5, 15.4.6.5.6, 15.4.6.5.7, 15.4.6.5.8, 15.4.6.5.8.1, 15.4.6.5.8.2, 15.4.6.5.8.3, 15.4.6.5.8.4, 15.4.6.5.8.5, 15.4.6.5.9, 15.4.6.5.9.1, 15.4.6.5.9.2, 15.4.6.5.9.3, 15.4.6.5.10, 15.4.6.5.10.1, 15.4.6.5.10.2, 15.4.6.5.10.3, 15.4.6.5.11, 15.4.6.5.11.1, 15.4.6.5.11.2, 15.4.6.5.11.3, 15.4.6.5.11.4, 15.4.6.5.11.5, Figs 15.4-1 thru 15.4-3, 15.5.1.6, 15.5.1.8, 15.5.1.10, 15.5.1.12, 15.5.1.13.3, Figs 15.5-5 & 15.5-6, 15.6, 15.6.1, 15.7, 15.7 Refs, 15A, 15A.3.1, 15A.3.2, 15A.3.3, 15A.3.4, 15A.3.5, 15A.3.5.1, 15A.3.5.2, 15A.3.5.2.1, 15A.3.5.2.2, 15A.3.4.2.3, 15A.3.5.2.4, 15A.3.5.3, 15A.4, 15A Refs, Tbl 15A-5 [FS 99-050]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of civil/structural/seismic topics.
KWI, Table 4.1-9, 5.4.1.3.5.4, Table 9.1-7, 9.4.4.7, Table 9.4-1, Figure 9.9-1, 14.2.5.2.1 [FS 99-044]	Incorporated updates to the key word index and corrected typographical, spelling, grammar and administrative errors.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
KWI, 5.3.1.1, 5.3.1.3.1, 9.3.3.2, 9.4, 9.4.1.1, 9.4.1.2, 9.4.1.3, 9.4.1.4, 9.4.1.5, 9.4.3.1, 9.4.3.2, 9.4.3.3, 9.4.3.5, 9.4.4.1, 9.4.4.3, 9.4.4.5, 9.4.5, 9.4 Refs, 9.4 RefDwgs, Tables 9.4-7 through 9.4-10, Figures 9.4-1 through 9.4-5, 9.9, 9.9.1, 9.9.2.1, 9.9.3.2, Table 9.9-3 [FS 99-022]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the component cooling water system.
1.1, 1.4.2, 1.4.28, 1.4.29, 1.4.31, 1.4.33, 1.6, 1.6.1.1, 1.6.2.8, 3.1, 3.2.1, 3.2.2.1, 3.2.3.1, 3.2.3.3, 3.2 Refs, 3.3.1, 3.3.2.1, 3.3.2.3, 3.3.2.10, 3.3.2.12, 3.3.2.13, 3.3.3.2.2, Table 3.3-1, Figures 3.3-1, 3.3-2, 3.3-3, 3.3-7, 3.3-8, & 3.3-9, Table 3.4-1, 3.6.1.2, 3.6.2, 3.6.3.1, 4.3.1.1, 4.3 Refs, 9.1.1.2, 9.1.2.3.1, 9.1 Refs [FS 2000-025]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of reactor design.
1.2.5, 1.4.70, 7.2.1.1, 7.7.1, 9.1.2.1, 9.1.2.6.15, 9.2, 9.2.1, 9.2.2, 9.2.3, 9.2.4, Tables 9.2-1 & 9.2-2, Figure 9.2-1, 9.7.2, 11.2.3, 11.2.3.1.1, 11.2.3.1.2, 11.2.3.1.3, 11.2.3.1.11, 11.2.3.2, 11.2.3.2.1, 11.2.4.1.3, 11.2.4.1.5, 11.2.4.2, 11.2.4.2.1, 11.2.4.2.3, 11.2.4.2.5, 11.2.4.2.7, 11.2.4.2.11, 11.2 RefDwgs, Tables 11.2-1, 11.2-8 through 11.2-10, Figures 11.2-1 & 11.2-2, 11A.4.2 [FS 99-031]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the boron recovery and waste disposal systems.
1.2.8, 1.4.24, 1.4 RefDwgs, 4.3.6, 7.7.1, 8.1, Figure 8.1-1, 8.2, 8.3, 8.3 RefDwgs, Figure 8.3-2, 8.4.1, 8.4.2, 8.4.3, 8.4.4, 8.4.6, 8.5, 8.6, 9.1.3.1 [FS 99-051]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the vital bus and station service systems.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.4.3, 7.2.2.1.1, 7.7.2, 9.1.2.1, 9.3.2.1, 9.4.3.1, 9.10.1, 9.10.2.1, 9.10.2.2.1, 9.10.2.2.3, 9.10.2.2.5, 9.10.2.2.7, 9.10.2.2.9, 9.10.2.3.2, 9.10.2.3.3, 9.10.2.4, 9.10.2.6, 9.10.2.8, 9.10.2.9, 9.10.3.3, 9.10.3.4, 9.10.3.5, 9.10.4.1, 9.10.4.3, 9.10.4.4, 9.10.4.5, 9.10.4.7, 9.10.4.8, 9.10.4.9, 9.10.4.10, 9.10.4.11, 9.10.4.12, 9.10.4.14, 9.10.4.15, 9.10.4.16, 9.10.4.17, 9.10.4.18, 9.10.4.19, 9.10.4.20, 9.10.4.22, 9.10.4.23, 9.10.4.24, 9.10.4.25, 9.10.4.26, 9.10.4.27, 9.10.5, 9.10.6, Table 9.10-1, 9.11.1, Table 9.11-1, Figure 9.11-1, 9.13.4.1, 10.3.9.3, 11.1, 11.1 Refs [FS 99-027]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the fire protection system.
1.4.5, 7.7.2, 9.1.2.2, Figure 10.3-2, 12.1.1.2.1, 12.4, 12.5, 12.6, 13.1, 14.2.2, 14.2.2.1, 14.2.5.1, 14.2.5.2.2, 14.2.9.2.3, 14.2.9.2.4.1, Table 14.2-4, Figure 14.2-84, 14.3.2.1, 14.3.2.2.1, 14.3.3.2.2.2, 14.3.3.2.2.4, 14.4.1.2.2.1, 14.4.2.1, Table 14.4-6, 14.5.2.3, 14.5.2.4.2, 14.5.3.3.2, 14.5.3.4.1, 14.5.5.2, 14.5 Refs, Table 14.5-14, Figures 14.5-5 & 14.5-38, 15.4.6 [FS 2000-023]	Corrected typographical, administrative, and format errors.
1.4.11, 5.3.1.2, 5.3.1.3.2, 3.1.3.3, 5.3.1.3.4, 5.3.1.4, 5.3.1.4.1, 5.3.1.5, Table 5.3-1, 6.3.1.4, 7.7.2, 9.13.1, 9.13.3.2, 9.13.3.1, 9.13.3.2, 9.13.3.3, 9.13.3.4, 9.13.3.5, 9.13.3.6, 9.13.3.7, 9.13.3.9, 9.13.4, 9.13.4.1, 9.13.4.2, 9.14.2, 9.14.3, 10.3.6.2, 10.3.8.2, 11.2.2, 11.2.5, Table 11.2-11, 11.3.3.14, 11.3.6 [FS 99-040]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the ventilation system.
1.4.18, 9.4.1.3, 9.4.3.3, Tables 9.4-2 through 9.4-5, 9.5.1, 9.5.3.4, 9.5 Refs, 9.5 RefDwgs, Figure 9.5-1, Table 10.3-4, Figure 10.3-11 [FS 99-049]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of spent fuel pool cooling, chilled water, and bearing cooling systems.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.4.24, 2.1.3.2, 2.4.3.3, 2.4.7.4, 2.4.8, Tables 2.4-13 & 9.5-1, 9.10.6, Figure 9A-1, 11.1 Refs, 15.2.4, Table 15.2-1, 15.4.1 [FS 99-058]	Corrected typographical, administrative, and format errors.
1.4.46, 6.2.2.2.3, 6.2.2.2.4, Tables 6.2-5 & 6.2-8 [FS 98-042]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the safety injection system.
1.4.49, 1.4.55, 1.4.57, 5.2.1, 5.2.2, Tables 5.2-1 & 5.2-2, 5.3.4, 5.3.4.1, 5.3.4.2, 5.3.4.3, 5.3.4.4, Tables 5.3-4 & 5.3-5, Figure 5.3-2, 5.4.2, 5.4.2.1, 5.4 Refs, 5.5.1, 6.1, Table 6.2-7, 6.3.1.1, 6.3.2, 6.3.2.1, 6.3.2.2, 6.3.2.3, 6.3.2.4, Tables 6.3-4 & 6.3-5, Figure 6.3-6, 7.5.1.4.2, 15.5.1.2, 15.5.1.8 [FS 99-039]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the containment systems.
1.5, 9.1, 9.1.1, 9.1.1.2, 9.1.1.3, 9.1.2, 9.1.2.1, 9.1.2.4, 9.1.2.4.1, 9.1.2.5, 9.1.2.6.1, 9.1.2.6.2, 9.1.2.6.7, 9.1.2.6.8, 9.1.2.6.9, 9.1.2.6.12, 9.1.2.6.15, 9.1.2.6.16, 9.1.2.6.17, 9.1.2.6.18, 9.1.2.6.19, 9.1.2.6.20, 9.1.3.1, 9.1.3.3, 9.1.3.5.2, 9.1.3.5.3, 9.1 Refs, Tables 9.1-1 through 9.1-3, 9.1-8, & 9.1-9, 9.3.1, 9.3.2.1, 9.3.2.2.2, 9.3.2.2.3, 9.3.3.1, 9.3.3.2, Tables 9.3-2 through 9.3-4, 9.4.1.1, 9.9.1.3 [FS 99-041]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the chemical and volume control and residual heat removal systems.
Figures 2.4-6 & 2.4-7, 6.2.3.10, 7.9.2.5, 7.10.2.1, 7.10.2.2, 12.1.1.2.1, 14.5 Refs [FS 2000-018]	Corrected typographical, administrative, and format errors.
3.6.3.1, 9A.2, 14.5.2.3 [FS 2000-040]	Corrected typographical, administrative, and format errors.
4.1.7.4, 4.1 Refs, Tables 4.1-13 through 4.1-15 [FS 2000-035]	Incorporated the most recently acquired and currently applicable reactor vessel material properties data.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 4.1-2, 9.10.3.3, 9.10.4.2, 9.10.4.3, 9.10.4.13, 10.3.1.2, 10.3.1.5, 10.3.3.1, 11.3.3.14, 14.3.1.2, 14.3.1.3, 14B.2.3.2.3, 14B.4.2, 14B.4.3, 14B.5.1.1, 14B.5.1.4, 14B.5.1.5, 14B.5.1.6, 14B.5.1.6.1, 14B.5.1.6.2, 14B.5.1.6.3, 14B.5.1.6.4, 14B.5.1.6.4.2, 14B.5.1.6.4.3, 14B.5.1.6.4.5, 14B.5.2.1, 14B.5.2.5, 14B.5.3.3, 14B.5.4.2, 14B Refs, Tables 14B-2, 14B-3, & 14B-9, Figures 14B-1 & 14B-10 [FS 2000-007]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the high energy line break.
Table 4.1-4, 10.3.1.2, 10.3.4.2, 10.3.5.2, 10.3.6.2, Figure 10.3-2 [FS 99-038]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the feedwater, condensate, steam generator blowdown, and condensate polishing systems.
4.2.11, 4.2 Refs, 9.3.1, 9.6.2.1, 9.6.2.2.6, 9.6.3.2, Tables 9.6-7 & 9.7-1, Figure 9.7-1, 10.3.8.1 [FS 99-047]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the sampling and primary vents and drains systems.
5.2.2, 5.2 Refs [FS 2000-031]	Updated the discussion of acceptable closure time of a normally closed manual isolation valve.
Table 5.2-1 [FS 99-054]	Reflected the addition of a new inside containment isolation valve.
Tables 5.2-1 & 5.2-2 [FS 99-045]	Updated Table 5.2-1 to reflect changes to valves subject to Type C testing as defined in 10 CFR 50, Appendix J. [10 CFR 50, Appendix J]

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
5.4.1.3.4, 6.2.2.1.4, 14.1, 14.1 Refs, 14.2.1, 14.2.2.2, 14.2.2.3, 14.2.4.2, 14.2.7.2, 14.2.7.3.1, 14.2.7.3.3, 14.2.7.4, 14.2.9.2.1, 14.2.9.2.2.2, 14.2.9.2.4.1, 14.2.9.2.4.3, 14.2.10.4.2, 14.2.13, 14.2 Refs, Figures 14.2-16 through 14.2-21, & 14.2-27, 14.3.1.1, 14.3.1.4.3, 14.3.1.4.4, 14.3.2.1, 14.3.2.2.1, 14.3.2.5, 14.3.3.1.1.2, 14.3.3.2.1, 14.3.3.2.1.2, 14.3 Refs, Tables 14.3-8, 14.3-11, & 14.3-12, 14.4.1.1, 14.4.1.2, 14.4.1.2.1, 14.4.1.2.2.2, 14.4.1.3.1, 14.4.2.1, 14.4.2.2.1, 14.5.1.2, 14.5.1.3, 14.5.1.8, 14.5.2.3, 14.5.2.4.2, 14.5.6, 14.5 Refs, Tables 14.5-2, 14.5-11, & 14.5-12, Figures 14.5-30 & 14.5-31 [FS 2000-016]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the plant safety analyses.
Table 6.2-6, Table 6.3-2, 14.5.5.3, 14.5 Refs [FS 2000-008]	Updated the allowable leakage from the safety injection and charging systems.
7.2.2.2.10, 7.3.2.2.3, 7.4.3.4, 7.4.3.6, 7.4.3.8, 7.4.4.1, 7.4.4.3, 7.4.4.4.2, 7.4.4.4.3, Table 7.4-3, Figure 7.4-2, 7.6.1, 7.6.2.1, 7.6.2.3.1, Figure 7.6-1, 7.11.1 [FS 99-035]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the nuclear instrumentation system.
7.3.1, 7.3.2.1, 7.3.2.2.1, 7.3.2.2.2, 7.3.2.3.1, 7.3.2.3.2, 7.3.3.2, 7.3.3.5, 7.3 RefDwgs, 7.7.2, 7.8.1, 7.8.2, 7.8.3, Figure 7.8-1 [FS 99-059]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the nuclear control system.
7.7.2, 9.10.3.5, 9.10.4.13, 10.3.1.2 [FS 99-033]	Incorporated changes to reflect that the decay heat release subsystem is no longer used and that decay heat release components have been removed on Unit 2.
7.12.1.1, 10.3.5.3 [FS 2000-022]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the electrical instrumentation and plant computer system.
9.4.4.3, 9.8.1, 9.8.2, 9.8.3, 9.8.4, Table 9.8-1, Figure 9.8-1, 10.3.9.3, Table 15.2-1 [FS 2000-011]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the instrumentation air system.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 9.4-1 [FS 96-032]	Updated the design data for the component cooling water heat exchangers to describe the replacement heat exchangers.
9.7.2, 11.2.2, 11.2.5, 11.2.5.1, 11.2.5.2.3, 11.2.6.1, Tables 11.2-2 & 11.2-3 [FS 99-028]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the gaseous waste disposal system.
9.7.3 [FS 99-023]	Incorporated a modification to the level detector and controls for the auxiliary building sump pumps.
9.9.1.2 [FS 99-007]	Updated the description of emergency service water pump capacity associated with a design change to improve pump reliability.
9.9.1.3 [FS 2000-034]	Provided additional information concerning the response required for hurricane conditions that are less severe than those produced by the probable maximum hurricane.
9.10.2.2.9, 9.10 Refs [FS 99-021]	Added a description of the design basis for the halon system in the emergency switchgear rooms.
9.10.3.3, 10.3.1.2 [FS 99-019]	Added a description of the local operation of the atmospheric steam dump valves.
9.10.4.8 [FS 2000-010]	Incorporated terminology from new EPA regulation, 40 CFR 279.22(c)(1).
9.12.4.4, 9.12.4.5, 9.12.4.6, 9.12.4.9, 9.12.4.13, 9.12.4.14, 9.12.5.2, 9.12.5.4, 9.12.6.2, 9.12.8, 9.14.2, 9A.2 [FS 2000-014]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of fuel handling and storage.
9.13.2, 14B.5.2.1 [FS 2000-004]	Incorporated the environmental impact of a turbine building high energy line break on the control room envelope, mechanical equipment room no. 5, and the emergency diesel generator room.
10.3.5.3, 14.2.11, 14.2.11.1, 14.2.11.1.1, 14.2.11.1.2, 14.2.11.1.3, 14.2.11.1.4, 14.2.11.2, 14.2.12, 14.2 Refs, Figures 14.2-79 through 14.2-89 [FS 2000-015]	Incorporated the description of the reanalysis of the loss of normal feedwater event and the loss of ac power to the station auxiliaries event.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 32—09/01/00 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
11A.4.1, 11A.4.2, Table 11A-1 [FS 96-065]	Added descriptions of the application of the Offsite Dose Calculation Manual.
12.4 [FS 2000-026]	Corrected the reference to the personnel qualification requirements for SNSOC and station supervisory personnel. [10 CFR 50.90 License Amendment]
14.2.13 [FS 98-050]	Specified that the governor and main stop valves are exercised on a periodic basis in order to eliminate part of the transient experienced during turbine inlet valve freedom testing.
14.5.1.6, 14.5.1.7, 14.5.2.6, 14.5.2.7, 14.5 Refs, Tables 14.5-5 & 14.5-18 [FS 99-060]	Incorporated descriptions of the peak clad temperature penalties and benefits in the large and small break LOCA analyses.
16.2 [FS 99-052]	Revised the description of the administrative controls that apply to the Technical Requirements Manual.
17.2.1.2, 17.2.2.1, 17.2.17, Figure 17.2.1-1 [FS 2000-033]	Modified organizational titles and reporting relationships associated with information technology.
17.2.1.2, 17.2.2.6, Figure 17.2.2-1 [FS 2000-009]	Updated organizational description to reflect Supply Chain Management (Generation) titles.
17.2.1.2, Figure 17.2.1-2 [FS 2000-020]	Modified organizational titles and reporting relationships associated with records management.
17.2.1.2, Figure 17.2.1-2 [FS 2000-036]	Modified organizational titles and reporting relationships associated with the radwaste facility.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
KWI, 1.4.9, 1.4.16, 4.1.3.1, 4.1.4, 4.1.7.1, 4.1.7.2, 4.1.7.4, 4.1 Refs, Tables 4.1-1, 4.1-5, 4.1-8, 4.1-10, & 4.1-11, 4.2.1, 4.2.2.1, 4.2.2.3, 4.2.2.3.1, 4.2.2.3.2, 4.2.2.3.3, 4.2.2.4, 4.2.2.7, 4.2.2.8, 4.2.3, 4.2.5, 4.2.6, 4.2.7.2, 4.2.9, 4.2.9.1, 4.2.9.2, 4.2.9.3, 4.2.9.4, 4.2.9.5, 4.2.9.6, 4.2.9.7, 4.2.10, 4.2.10.1, 4.2.10.2, 4.2 RefDwgs, Tables 4.2-3 & 4.2-4, Figures 4.2-8 & 4.2-11, 4.3.1.3, 4.3.2, 4.3.3.1, 4.3.3.2, 4.3.4.2, 4.3.6, 4.3 Refs, Tables 4.3-4 & 4.3-5, 4.4.1.4, 7.2.3.2.3, 7.3.2.4, 7.10.1, 7.10.2.3, Table 7.10-1, 9.10.3.2 [FS 99-001]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the reactor coolant system.
KWI, 4.2.2.2, 6.2.3.3, 6.3.2.1, Tables 6.3-1 & 3, 7.6.2.1, 7.6.3, 7.10 References, 8.4.1, 8.4.4, Tables 11.2-8 & 9, 11.3.3.10, 14.2.6, 14.5.1.1, 14.5.1.4, 14.5.2.3, Table 14.5-14 [FS 98-052]	Provided grammatical and editorial corrections.
KWI, Tables 5.2-1 & 5.2-2, 7.5 References, 9.1.2.3, Table 9.5-1, App 9B, 10.3.5.2, 10.3.5.3, 11.2.2, 11.2.3, 11.2.4, Tables 11.2-1 & 11.2-11, Figures 11.2-4 through 11.2-6, 11.3.3.1, 14.2.11, 14B.5.1.7, 16.2.2.1 [FS 99-004]	Revised key word references, corrected formatting, typing, and capitalization errors, updated reference lists and references in text, added a list of tables to App 9B, and replaced a non-standard drawing symbol.
KWI, 15.3.2 [FS 95-045]	Added references to the key word index and expanded the description of the containment reinforcing steel.
Ref Dwgs: 1.2, 1.4, 2.1, 2.3, 4.2, 5.3, 6.2, 7.2, 7.3, 7.7, 8.3, 8.4, 9.1, 9.2, 9.3, 9.4, 9.5, 9.6, 9.7, 9.8, 9.9, 9.10, 9.11, 9.12, 9.13, 9.14, 10.2, 10.3, 11.2, 11.3, 15.1, 15.5; Section 9.9 [FS 99-006]	Corrected reference drawing descriptions, eliminated duplicate entries, and added companion Unit 2 drawings, where appropriate, in the reference drawing list and revised drawing reference numbers in the text.
1.4.16, 1.4.17, 4.2.7.1, 7.7.2, 9.13.1, 9.13.4.1, 11.3.3, 11.3.3.1, 11.3.3.3, 11.3.3.7, 11.3.3.8, 11.3.3.10, 11.3.3.13, 11.3.3.14, 11.3.4.1, 11.3.4.2, 11.3.4.3, 11.3.4.4, 11.3.4.7, 11.3.6, 11.3 RefDwgs, Tables 11.3-6 through 11.3-9 [FS 99-002]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the radiation monitoring system.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.4.17, 6.3.1.2, Table 9.4-7, 9.9, Tables 9.9-1&2, Figure 9.9-1, 9.10.4.17 & 18 [FS 98-014]	Incorporated technical and editorial corrections and clarifications related to the Service Water (SW) System: deleted singular SW flow rate through recirculation spray heat exchangers, corrected the description of the emergency service water pumps, and enhanced the description of the high-level intake canal.
1.4.39, 8.5, Table 8.5-1, 9.10.2.4, & 9.10.4.19 [FS 98-022]	Incorporated technical and editorial corrections and clarifications related to the Emergency Diesel Generator (EDG) System: improved the description of testing, enhanced the description of the auto tap changer configuration, corrected the EDG day tank capacity, rewrote the description of the undervoltage setpoint scheme, and improved the description of load sequencing.
1.4.59, Table 5.4-20, 6.1, Figures 6.1-1 & 2, 6.2.3.3, 6.3.1.3, 6.3.1.5.1, 6.3.1.5.2, 6.3 References, Tables 6.3-1 & 3, Figure 6.3-1, 13.1, Table 13.1-1, 13.5, 13.5.1, 13.5.1.1, 13.5.1.2, 13.5.1.3, 13.5.1.3.1, 13.5.1.3.2, 13.5.1.3.3, 13.5.1.3.4, 13.5.1.3.5, 13.5.2, 13.5 References, Tables 13.5-1 & 13.5-2 [FS 98-027]	Incorporated technical and editorial corrections and clarifications related to the Containment Spray (CS) System: improved the description of testing; designated historical information; corrected a cross-reference; corrected the figure depiction of the RWST, CS pumps, and spray headers; reflected the analyzed amount of time of system operation; enhanced the description of electrical cables; reworded RWST welding requirements; changed the RWST material description; clarified the capacity, heat tracing, and insulation of the chemical addition tank (CAT); resolved discrepancy regarding the manifold drain line; clarified description of electrical equipment testing; corrected rated pump flow; corrected pump motor insulation class; corrected nominal RWST operating temperature; clarified CAT pump horsepower rating; clarified pump operating temperature and test pressure description; clarified the description of check valves; and changed the depressurization time and subatmospheric peak pressure.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.4.68, 1.4.69, 9.1.2.2, 11.2.2, 11.2.3, 11.3.2.1, 11.3.2.2, 11.3.2.6, 11.3.2.9, 11.3.5.8, Tables 11.3-3 & 11.3-4, 11A, Table 11A-1 [FS 99-016]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the radiation protection system.
1.5, 4.3.1.2, 6.2.2.2.7, 10.2 RefDwgs, Figure 10.2-1, 10.3.1, 10.3.1.1, 10.3.1.2, 10.3.1.3, 10.3.3, 10.3 RefDwgs, 14.3.2 [FS 99-012]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the main steam system.
Table 2.1-4, 10.3.1.4, 10.3.5.2 [FS 96-063]	Added ethanolamine to the list of chemicals used for pH control.
2.2.1.1, 2.2.1.2, 2.3.1.2.2, Table 9.4-9, 9.12.9.2, 11.3.4.5, Table 11A-1 [FS 99-024]	Updated text, table, and figure cross references; corrected typographical errors; revised non-standard number and unit formats; and sorted a table in alpha-numeric order.
2.3.1.1, 2.3.1.2.1, 2.3.2, 2.3 Refs, Tables 2.3-1 through 2.3-4 [FS 95-038]	Updated the mean monthly discharge and flood discharge rates, added new references, and revised the descriptions of on-site and off-site wells.
3.2.1 [FS 96-054]	Removed the description of boron injection via the safety injection system.
3.5.2.3 [FS 97-008]	Revised the description of secondary neutron sources to reflect that they are optional in reload cores.
4.1.2.6, 4.2.7.1 [FS 96-059]	Removed references to monitoring containment leakage by monitoring containment humidity.
4.1.7.4, 4.1 Refs, Tables 4.1-14 & 4.1-15 [FS 99-018]	Updated reactor pressure vessel toughness data associated with Technical Specification Basis change.
Table 4.2-2, 9.1.2.6.8 [FS 97-005]	Revised the reactor coolant dissolved hydrogen guidelines to include startup, shutdown, and off-normal conditions.
4.3.3.1 [FS 98-006]	Modified the description of inservice inspection requirements on the reactor coolant pump flywheel. [10 CFR 50.90 License Amendment]
4.3.4.2 [FS 96-053]	Clarified the function of the PORV backup-air spare bottles.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 5.2-1, 5.3.1.3.1, 9.4.1.1, 9.4.4.7, 9.12.9.3, 9.13.4.2, 11.2.3.1.7 [FS 99-037]	Updated text cross references, corrected typographical errors, and improved grammatical usage.
Table 5.2-2 [FS 96-021]	Added the description of a new valve to containment penetration No. 24.
Table 5.3-2, 9.4.1.2, 9.4.3.2, Tables 9.4-2, 9.4-5, & 9.9-2, Figure 9.9-1, Table 10.3-4, Figure 10.3-11 [FS 98-030]	Updated the description of the Unit 1 chilled water system to reflect equipment replacement and changing the system's source of cooling water.
5.4.1.2 [FS 97-009]	Incorporated a description of the revised method of calculating core stored energy.
6.2.2.2.4 [FS 99-029]	Incorporated modifications to the safety injection system.
6.2.3.12, 6.2.3.13 [FS 99-020]	Added a description of the portable passive autocatalytic recombiner and its use.
Table 6.2-6, Table 6.3-2, & 14.5.5.2 [FS 96-030]	Improved consistency with the Technical Specifications' description of safety injection and recirculation spray loop leakage limits.
Figures 6.2-1 & 6.2-2 [FS 99-005]	Incorporated modifications to the Unit 2 safety injection system.
6.3.1.3 [FS 98-043]	Corrected typographical omission of a passage of recirculation spray pumps' cylindrical suction screens.
6.3.1.5.2 [FS 98-026]	Clarified the description of the initial testing of the recirculation spray system.
7.1, 7.1.1, 7.1.2, 7.2 Refs, 7.2.2.1.1, 7.2.2.1.4, 7.2.2.1.6, 7.2.2.4, 7.2.3.3, 7.2 RefDwgs, Tables 7.2-1 & 7.2-3, Figures 7.2-6, & 7.2-8 through 7.2-11, 7.5.1, 7.5.1.2, 7.5.1.3, 7.5.1.4.1, 7.5.1.4.2, 7.5.2.2, 7.5.2.3.2, 7.5.3.5, Tables 7.5-1 & 7.5-2, Figures 7.5-1, 7.5-2, 7.5-4, & 7.7-1, 10.3.5.3, Table 13.1-1 [FS 98-048]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the reactor protection system.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
7.3.2.6, 8.1, 9.2, 9.4, 9.4.4.5, 9.5, 9.9, 9A.3.2.2.1, 9C.1, 9C.1.1, 10.3.1, 10.3.1.2, 10.3.2, 10.3.4, 10.3.5, 10.3.5.3, 10.3.9, 11.2.3.2, & Table 11.2-11 [FS 99-015]	Incorporated editorial changes and corrections to typographical errors.
7.4.3.2 [FS 97-030]	Added new type of cable to the description of the source range nuclear instrument channels.
8.4, 8.5 [FS 99-010]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the emergency power system.
8.4.4, 8.4.5 [FS 98-029]	Added descriptions of concurrent power supplies to the new Unit 1 main control room Hathaway annunciator.
8.4.4, 8.4.5 [FS 99-009]	Adds a description of the concurrent electrical supplies to the main control room Hathaway annunciators.
8.5 [FS 98-031]	Clarified the EDG start/load acceptance time and power rating.
9.1.2.4, 9.1.2.4.1, 9.1.2.4.2, 9.1.2.4.3 [FS 96-050]	Clarified the description of operation of the reactor makeup control.
9.1.2.6.22 [FS 97-003]	Correct the description of chemical and volume control system piping operation an inspection.
Table 9.1-6 & 14.4.2.1 [FS 98-046]	Revised the description of the volume control tank rupture accident analysis.
9.2 & 10.3 [FS 93-22]	Identified equipment described in the UFSAR that is installed but no longer used.
9.3.3.1 [FS 98-017]	Removed non-combustible from the description of the radiant energy shield between the RHR pump motors.
9.4.1.1, 9.4.3.1, 9.4.3.2, 9.4.4.1, 9.4.4.3, 9.4.4.5, 9.4.5, Table 9.4-2 [FS 97-006]	Incorporate changes to the description and operation of the component cooling system.
9.4.3.1 [FS 98-002]	Revises the component cooling water chemistry chromate concentration and pH limits.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.4.3.2 [FS 96-008]	Incorporated a revised description of the modified chiller alarms.
9.4.3.4 [FS 97-018]	Added a description of the charging pump seal cooling system modification to a once-through cooling system.
9.4.4.1 [FS 96-025]	Removed the description of automatic closure of the primary drain cooler component cooling return line.
Table 9.4-8 [FS 97-023]	Deleted the table description of the condensate makeup line check valve.
9.5.1, 9.12.5.5, 9.12.9.1, 9.12.9.2, 9.12.9.3, Table 9.12-1 [FS 96-012]	Updated the description of spent fuel handling and the requirements for cask handling in and around the spent fuel pool.
9.5.3.4 [FS 97-016]	Deleted the reference to an assumed value for fuel assembly offload rate.
Table 9.5-3 [FS 97-029]	Added description that power to the spent fuel pool cooling pumps is supplied from emergency buses.
9.9 & 9.10.4.17 [FS 98-041]	Provided grammatical and editorial corrections.
9.9.1.3, 9.10.4.13, 10.3.1.5, 10.3.5.1, 10.3.5.2, 10.3.5.3, 10.3.5.4, Table 13.5-2, 14B.5.1.7, Figure 14B-20 [FS 98-037]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the Auxiliary Feedwater System.
9.9.2 [FS 98-018]	Added the description of a temporary service water supply path to the component cooling heat exchangers. [10 CFR 50.90 License Amendment]
9.12.3.4, 11.3.4.1, 11.3 References [FS 97-042]	Incorporated the exemption form criticality monitoring in the fuel storage and handling areas. [10 CFR 70.14 Exemption]
9.12.4 & App. 9B.1 [FS 97-002]	Enhanced the description of heavy loads and their handling.
9.12.5.4 [FS 97-022]	Revised the refueling reassembly sequence to reflect current practice.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.12.5.4 [FS 98-040]	Improved the refueling procedure reassembly sequence.
9.12.9, 9.12.9.2, 9.12.9.3 [FS 99-030]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the Surry ISFSI.
9A.1, 9A.2, 9A.3.1.2, 9A.3.1.3.2, 9A.3.1.4, 9A.3.1.5, 14.4.1.3.2, 14.4.1.3.2.1, 14.4.1.3.2.2, 14.4.1.3.2.3, Table 14.4-3 [FS 97-017]	Revised the fuel assembly drop discussions using a 42 inch drop in lieu of a 24 inch drop and corrected typographical errors.
9B.2.4.4 [FS 97-001]	Added the SFP transfer canal gate lift rig to the list of special lifting devices.
9C.1, 10.3.4.2, 10.3.4.3 [FS 99-014]	Incorporated technical and editorial corrections and clarifications resulting from the integration review of the circulating water system.
10.3.1.2 [FS 94-040]	Added a description of the new condensate return divert line to the steam generator blowdown heat exchangers.
10.3.1.4 [FS 98-036]	Updated the description of the secondary plant chemistry monitoring and control.
10.3.5.1 [FS 95-017]	Removed extraneous detail from the description of the steam generator feedwater pumps.
10.3.7.3, 10.3.7.4 [FS 96-058]	Corrected the description of the function and testing of the dc motor-driven oil pump.
10.3.12 [FS 97-021]	Clarified the description of the main steam trip valve Appendix R solenoid operated valves.
11.2.3, 11.2.3.1.8, Figure 11.2-4 [FS 97-041]	Revised the description of the RF liquid waste reverse osmosis system.
11.2.3.1.7, 11.2.4.1.4, Table 11.2-1 [FS 96-039]	Added a description of the new RF liquid waste reverse osmosis system and revised liquid waste handling descriptions.
11.2.3.1.8, Figure 11.2-4 [FS 99-017]	Clarified the operation of the liquid waste reverse osmosis and demineralizer system.
11.2.5.3.4 [FS 95-036]	Incorporated a revised description of the modified waste gas decay tank oxygen analyzer.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
11.3.4.3 [FS 96-007]	Corrected the nominal counting rates for limiting isotopes of the containment gas monitors.
11.3.5.1, 11.3.5.3, 11.3.5.5, 11.3.5.6, 11.3.5.7, 11.3.5.9 [FS 96-033]	Incorporated changes to the Radiological Environmental Monitoring Program
12.2.2.3, 12.2 References [FS 97-045]	Revised reactor operator training program references.
12.7 [FS 97-014]	Incorporated revised security plan references.
14.2.6, 14.2.6.1, 14.2.6.1.1, 14.2.6.1.2, 14.2.6.2, 14.2.6.2.1, 14.2.6.2.2, 14.2.6.2.3, 14.2.6.2.4, 14.2.6.2.5, & 14.2.6.3 [FS 95-041]	Revised the startup on an inactive loop accident analysis description.
14.2.11, 14.3.2, 14B.4.2, 14B.6, 14B.6.1, 14B.6.2, 14B Refs [FS 99-032]	Augmented the description of effects of piping system breaks outside containment with a transient analysis of a high-energy line break in the main steam valve house.
14.3.2 [FS 96-044]	Revised wording to clarify the main steam pipe break description.
14.5.5.3, 14.5 Refs [FS 99-036]	Incorporated the results of a sensitivity analysis performed to evaluate acceptable quantities of emergency core cooling system in conjunction with potentially unfiltered exhaust from the Auxiliary Building.
15.5.1.8 [FS 96-051]	Revised the description of containment electrical penetrations to address variations between manufacturers.
16, 16.1, 16.2, 16.2.1, 16.2.1.1, 16.2.1.2, 16.2.2, 16.2.2.1, 16.2.2.2, 16.2.2.3, Tables 16.2-1, 16.2-2, & 16.2-3 [FS 99-008]	Relocated requirements for plant operation and surveillance of systems to the Technical Requirements Manual (TRM). Explicitly incorporated the TRM into the UFSAR.
17.2.2.5 [FS 98-049]	Updated the qualification requirements for Oversight personnel.
17.2.16.2 [FS 98-051]	Incorporated a title change.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 31—09/01/99 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
Table 17.2-0 [FS 98-038]	Revised the description to indicate the both Innsbrook record vaults meet ANSI requirements.

Revision 30—09/01/98

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
1.4, 6.1, 6.2, 6.3.1.5, 7.5.3.5, Tables 5.2-1&2, Tables 5.4-18, 19, & 20, Tables 6.2-2, 3, 4, 5, 6, 10, 11, 12, &13, Figs. 6.1-1 & 6.2-2 [FS 98-015]	Incorporated technical and editorial corrections and clarifications related to the Safety Injection System.
1.4.59, 5.3.3, 6.2.3, 6.3.1, 7.5.2.2, 11.3.3.10, Tables 6.3-1 & 3, Figs. 6.3-2, 3, & 5 [FS 98-019]	Incorporated technical and editorial corrections and clarifications related to the Recirculation Spray System.
2.2.1.1, Table 2.2-7, 2.5.3.2, 6.1, 6.2.2.1.2, Table 6.2-1, 6.2.3.12.1, 6.2.4.1.4, 6.2 References, 7.4.3.6, Figure 7.5-1, 8.3, 9.6, 9.8, 9.10, 9B.2.1, 9B.2.4.1, 9B.2.4.4, 9B.2.4.7, 9C, 11.2, Tables 11A-6, 7,9 & 10, Table 14.3-15, Table 14.5-11, 15.5.1.8 & Table 16.2-2 [FS 98-032]	Corrected references, typographical errors, and verb tense; clarified an abbreviated term and illegible text; and corrected format of numbers, upper/lower case usage, and text lists.
3.3.3.2.2, 3.5, App. 9A & Tables 3.3-1 & 9.12-1 [FS 97-043]	Increased the maximum fuel enrichment from 4.1 to 4.3 weight percent U-235. [10 CFR 50.90 License Amendment]
4.2.2.3.2 [FS 98-024]	Added a description of the removal of the steam generator channel head drain lines.
5.3.1 & 9.13 [FS 96-061]	Revised description of auxiliary ventilation and containment ventilation systems to reflect changes in these systems design and operation.
5.4 & Tables 5.4-17, 5.4-18, 5.4-19, 5.4-20, 6.2-11, 6.2-12 & 6.2-13 [FS 97-040]	Removed Containment concrete floor plugs and the Pressurizer cubicle roof plug.
6.2.2.1.1 & Table 6.2-2 [FS 96-047]	Updated the description of the Safety Injection control board indication.
6.2.2.1.3 [FS 96-027]	Changed to state that pressure-relieving devices discharge to the liquid waste disposal system.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 30—09/01/98 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
6.2.2.2.1 [FS 97-039]	Clarified the tanks to which the accumulators may be drained.
6.2.2.2.4 & 6.2 References [FS 96-040]	Revised description of safety injection valves MOV-1890A/B and MOV-2890A/B to reflect addition of pressure equalization line. Added Reference to NRC Generic Letter 95-07.
6.2.3.3 [FS 98-007]	Changed containment spray and minimum recirculation spray pH ranges.
6.2.3.10, 6.2.4.1.4, 6.3.1.4, 15.5.1.3, 15.5.1.12 & Figure 15.5-1 [FS 97-007]	Revised the description of the Containment ground water control equipment, ground water protection methods, and liquid level alarms.
6.2.3.12 [FS 98-009]	Changed post-LOCA containment hydrogen concentration for new initial conditions.
6.2.3.12.1 [FS 96-052]	Revised valve stroke time for isolation of the volume control tank.
6.2.4.1.3, 6.2.4.1.4 [FS 96-046]	Changed to describe SI system testing as a series of tests during refueling, and to state that accumulator discharge check valves are tested during refueling.
6.3.1.2.1 [FS 97-004]	Removed the statement that sodium hydroxide solution was only present in the containment spray system during system operation.
6.3.1.4, Tables 6.2-12 & 13 [FS 98-021]	Revised description of NPSH to the recirculation spray pumps to include impact several minor phenomena with impact on post-LOCA sump level.
7.2.3.2.7 [FS 98-010]	Clarified the description of the AMSAC C-20 setpoint.
8.6 [FS 93-33]	Clarified preventive maintenance program requirements by deleting the statement which implies that insulation testing is performed on all electrical equipment.
9.9.1.2 & 9.9.3 [FS 96-011]	Updated the description of Emergency Service Water Pump, 1-SW-P-1A, to indicate the removal of the electric motor drive.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 30—09/01/98 (continued)

Section	**Changes** Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
9.9.1.3 & 9.10.4.18 [FS 96-055]	Clarified the description of actions taken prior to the arrival of a hurricane onsite and corrected the classification of the circulating water valves as safety related.
9.9.2 & Table 2.1-4 [FS 96-036]	Updated the description of service water chemical treatment and updated the list of onsite chemicals.
9.10.4.16 [FS 98-025]	Updated the description of Emergency Service Water Pump, 1-SW-P-1A, to indicate the removal of the electric motor drive.
10.3.1.2 [FS 98-013]	Removed the statement that the Main Steam Safety Valves temperature flow probes are required for compliance with Regulatory Guide 1.97.
10.3.5.3, 14.2.11.1.3 [FS 96-041]	Relocated the stated numerical value of auxiliary feedwater (AFW) flowrate from the section describing the AFW system to the section where event analysis is described.
11.2.2, 11.2.5, & Tbl. 11.2-11 [FS 97-035]	Modified descriptions of process vent system to remove implied wind speed limitations for system operation.
12.1.1.2.1, 17.2, & KWI [FS 98-003]	Updated Station Manager title to Site Vice President and Assistant Station Managers titles to Manager-Station O&M and Manager-Station S&L. [10 CFR 50.90 License Amendment]
14.2.7 [FS 98-11]	Updated the description of the feedwater temperature reduction event.
14.3.1 [FS 97-034]	Revised the steam generator tube rupture accident analysis to reflect the evaluation of the effect of steam generator tube bundle uncovery on radioiodine release.
17.2.1.2.B.1 [FS 98-028]	Identified the Site Vice President as the station position fulfilling the Plant Manager position identified in the ISFSI Technical Specifications.

Revision 30—09/01/98 (continued)

Section	Changes Made under the provisions of 10 CFR 50.59 except where indicated in brackets.
17.2.3 [FS 98-016]	Revised to reflect replacement of A/E Instruction Manual with an Engineering Standard.

Revision 29—3/1998

Section	Changes
17.2, 17.2.1.2, 17.2.2.1, 17.2.3, 17.2.4, 17.2.5, Figure 17.2.1-1, and Table 17.2-0 [FS 97-026]	Deleted reference to Nuclear Operations Department Standards and replaced with Nuclear Business Unit Standard. Added position of Project Manager (Configuration Management).
17.2.1.1 and 17.2.1.2 [FS 98-004]	Clarified organizational position descriptions by noting responsibilities for the ISFSI as they already exist.
17.2.1.2, Figure 17.2.1-2, and Figure 17.2.1-3 [FS 98-005]	Deleted the position of Supervisor Administrative Services in the Nuclear Management organization and assigned duties and responsibilities to other positions.
17.2.2.6 and 17.2.2.8 [FS 97-038]	Clarified Quality Inspection Coordinator qualifications.
17.2.17, Tables 17.2-2 and 17.2-3 [FS 97-048]	Added Generic Letter 88-18 commitment regarding storage of quality assurance records on optical disk media.
Table 17.2.0 [FS 96-049]	Added provision for storage of quality assurance records in an approved offsite facility.
Table 17.2-0 [FS 97-044]	Provided an additional alternative to ANSI/ANS 3.1.
Tables 17.2-2 and 17.2-3 [FS 98-012]	Clarified the description of onsite and offsite nuclear safety review committees.

Intentionally Blank

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 28—02/11/98

Section	Changes
Foreword	Updated to reflect recent NRC initiatives regarding UFSAR submittal requirements, and adequacy and consistency of design basis information; and to note Virginia Power's adoption of electronic methods to enhance UFSAR maintenance, and UFSAR distribution in both hardcopy and electronic media.
5.5 [FS 95-039]	Modified leak rate testing discussion to include 10 CFR 50, Appendix J, Option B performance-based leak rate testing rulemaking.
7.5.1.1 [FS 96-045]	Changed low-low pressurizer SI manual block setpoint from 2000 psia to 2000 psig.
9.6 [FS 95-043]	• Added introduction and revised subsection headings • Clarified the 3-hour requirement for PASS samples • Deleted references to sampling abandoned flash evaporators • Noted that condenser tube leakage monitoring may be by means other than chlorides monitoring • Deleted superfluous HRSS equipment brand names • Clarified operation of the HRSS waste tank • Clarified remote indication of HRSS parameters • Clarified SS valve isolation on an SI signal • Clarified environmental qualification of HRSS containment sump pump
9.10 & 17.2 [FS 96-042]	Deleted references to the Training Center records vault and associated features.
9.12 [FS 96-022 R1]	Updated to reflect current refueling practices.
14.5.2 [FS 96-057]	Updated to reflect reanalysis of small break loss of coolant accident (SBLOCA), including Tables 14.5-14 thru 16, and Figures 14.5-36, and 38 thru 68.

Click on Change Package Number Highlighted in Red to View Change Request.

Revision 28—02/11/98 (continued)

Section	Changes
Table 17.2-3 [FS 97-037]	Corrected typos.
All (no change bars) [FS 97-012] [FS 97-013]	• Consolidated 7 volumes to 4 volumes • Referenced Station Drawings previously included in UFSAR; inserted simplified diagrams • Removed notations associated with previously deleted material and renumbered sequentially • Renumbered previously inserted items that had suffixes (e.g., 4A, 4B) • Applied consistent typeface and page layouts • Improved consistency of measurement notation (e.g., time, mass, velocity), including abbreviations

Surry Power Station
Updated Final Safety Analysis Report
Table of Contents

Surry Power Station
Updated Final Safety Analysis Report
Table of Contents (continued)

Surry Power Station
Updated Final Safety Analysis Report
Table of Contents (continued)

Surry Power Station
Updated Final Safety Analysis Report
Table of Contents (continued)

Surry Power Station
Updated Final Safety Analysis Report
Table of Contents (continued)

Surry Power Station
Updated Final Safety Analysis Report
Table of Contents (continued)

Surry Power Station
Updated Final Safety Analysis Report
Table of Contents (continued)

Intentionally Blank

FOREWORD

In the May 9, 1980, edition of the Federal Register (45 FR 30614), the NRC published a Final Rule requiring all licensed reactors to periodically update their Final Safety Analysis Reports. The purpose of the Rule was to establish baseline reference documents to be used in recurring safety analyses by licensees, the NRC, or other interested parties.

The “Supplementary Information” section of the Final Rule notice stated that submittal of an updated FSAR does not constitute a licensing action, but is only intended to provide information. The NRC Staff may review the material submitted, but does not intend to formally approve it. The NRC intends to use the updated FSAR in the future for appropriate applications such as reporting of deviations from conditions stated in the UFSAR.

The Rule became effective July 22, 1980, and established the following basic requirements for Vepco’s nuclear power stations:

- A complete Updated FSAR (UFSAR) was required as the initial submittal
- The UFSAR was to reflect information and analyses submitted to the NRC by Vepco, or prepared by Vepco pursuant to NRC requirements, since submission of the original FSAR (or, as appropriate, the last UFSAR)
- NOTE: The “Supplementary Information” section of the Final Rule notice clarifies this requirement by stating that no analyses other than those already prepared or submitted pursuant to NRC requirements are required because of the Rule: however, FSAR analyses that are known to be nonconservative based on new analyses must be updated. Other new analyses not previously included in the FSAR may be incorporated in the UFSAR at the option of the licensee. Furthermore, specialized studies provided in the original FSAR (e.g., seismology, meteorology) should include the latest information developed in response to NRC requirements when these studies are transferred to the UFSAR, and program type material referenced by the UFSAR (e.g., security plan, emergency plan, QA Program) should be referenced accurately. In addition, the level of detail in the UFSAR should be at least the same as but not necessarily greater than that provided in the original FSAR. Information on design changes should not be included until the changes are approved for use and operable.
- The initial UFSAR was due no later than July 22, 1982
- The initial UFSAR was required to be up-to-date as of a maximum of six months prior to the date of filing (January 31, 1982, was chosen by Vepco as the cutoff date)
- Subsequent updates are required at least annually and must reflect changes made up to a maximum of six months prior to the date of filing

- One original and 12 copies of the initial UFSAR and subsequent updates are required to be submitted to the NRC
- The updates are required to be certified by a duly authorized officer of Vepco
- The initial UFSAR should be a clean document without change bars and revision numbers. The subsequent annual revisions should include change indicators and page change identification

In response to the foregoing FSAR update requirements, Vepco and NUS Corporation executed an Agreement for FSAR update services in April 1981, and NUS began work on the project immediately. The project was accomplished in four basic phases:

1. Document Retrieval
2. Change Package Development
3. FSAR Revision
4. Printing

- During the initial document retrieval phase in the Spring of 1981, NUS engineers researched the licensing correspondence files at Vepco offices in Richmond and the design change files at the plant sites. All documents potentially affecting the FSAR were copied and taken to the NUS home office.

  Following the initial document review phase, NUS engineers periodically visited Richmond and the plant sites to acquire newly developed information. NUS was also placed on the distribution list for Vepco/NRC correspondence.

  The document retrieval phase continued until early 1982, at which time sufficient information was available to document changes up to the January 31, 1982, cutoff date.

- The documentation retrieved during the first phase was reviewed in detail during the second phase to determine the particular “two-digit” section or sections of the FSAR that should be revised, i.e., 1.1, 1.2, 1.3, etc. Copies of the document (or of the particular pages of the document that were of interest) were placed in separate files corresponding to the two-digit sections. These files were defined as “change packages.” Development of the change packages continued in parallel with the document retrieval phase, with new information being reviewed and assigned to appropriate change packages. The final change packages became a work product delivered to Vepco on conclusion of the update effort and are available for tracing the sources of changes to the original FSARs
- After development of the initial change packages the material filed therein was used in the third phase of the project to make the actual FSAR revisions. The revision process continued in parallel with the continuing development of the change packages.

The revision phase for most FSAR chapters included two cycles of Vepco review and comment. These comments became part of the change packages and were used in the development of the final draft UFSAR.

- Vepco reviewed and approved the final draft chapters of the UFSARs for printing. The printer prepared approximately 125 sets of the UFSARs. NUS delivered one original and 12 copies of the UFSAR directly to the NRC on July 20, 1982, for Surry and July 22, 1982, for North Anna. The original UFSARs were transmitted under cover letter supplied to NUS by Vepco (see the attachment to this foreword). The remaining copies were shipped to Richmond and the plant sites.

The following work products were also delivered to Vepco by NUS and are available for use in producing subsequent annual updates:

- Printer's copy of the UFSARs
- Annotated FSARs (2 copies)
- Final Change Packages (2 sets)
- Plant Drawing Indexes
- Key Word Indexes
- IBM Displaywriter Floppy Discs (2 sets each of the FSAR, Annotated FSAR, and Key Word Index)
- Update Procedures
- Introductory Volumes to the FSARs including this foreword, a list of effective pages, the key word indexes, the plant drawing indexes and a record of changes

Further 10 CFR 50.71(e) rulemaking pertaining to UFSAR requirements for nuclear power stations was promulgated as recently as July 29, 1996 [61 FR 39278]. In particular, the annual revision requirement has been relaxed to six months after each refueling outage provided the interval between successive updates does not exceed 24 months.

The NRC issued a letter to licensees dated October 9, 1996, entitled Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Basis Information. The letter required submittal of information that will provide the NRC added confidence and assurance that Virginia Electric and Power Company's nuclear plants are operated and maintained within their design bases and that any deviations are reconciled in a timely manner. The Company's response (Serial No. 96-535) dated February 7, 1997, described previously conducted programmatic reviews of the Updated Final Safety Analysis Report (UFSAR). The 1996 UFSAR Project Team examined the existing administrative controls for maintaining UFSAR content and usability. Process enhancements to simplify administrative controls, to increase accountability for technical content, and to improve UFSAR accessibility and usability are promoted by conversion to electronic media.

Under separate cover (Serial No. 97-108) dated May 23, 1997, Virginia Electric and Power Company notified the NRC about its project to address potential regulatory concerns involving the current design and licensing bases for the Surry and North Anna Power Stations. This project scope exceeds the level of scrutiny normally applied to the current licensing basis through routine surveillance and quality assurance activities. In order to facilitate thorough review, exhaustive validation, and a rigorous corrective action process, the recommended conversion to electronic media was implemented in Revision 28 of the Surry UFSAR. The entire text of the UFSAR was entered into electronic media. The conversion was accomplished by a process of augmenting recent UFSAR revision word processing packages with “scanned-in” optical character recognition documents for the balance of text, tables, and figures not previously stored electronically. A 100-percent word-for-word proofing was conducted by comparing a printed version of the entire electronic document with current controlled distribution copies. Thus, the electronic UFSAR was conveyed into service as the quality assurance document of record without introducing any substantive, technical, or non-editorial changes.

VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

R. H. LEASBURG
VICE PRESIDENT
NUCLEAR OPERATIONS

July 16, 1982

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Serial No. 424
NO/GSS:acm
Docket Nos. 50-280
50-281
License Nos. DPR-32
DPR-37

Gentlemen:

UPDATED FINAL SAFETY ANALYSIS REPORT
SURRY POWER STATION UNITS NO. 1 AND 2

Pursuant to 10 CFR 50.71(e), the Virginia Electric and Power Company hereby submits the Updated Final Safety Analysis Report (UFSAR) for the Surry Power Station Units No. 1 and 2. One signed original and twelve additional copies of the UFSAR are enclosed.

The UFSAR contains all the necessary changes since the submission of the original FSAR. This UFSAR is up to date as of February 1, 1982 which is within six months prior to the date of this letter.

The enclosed UFSAR is a completely new document without the pages from the original FSAR. It is not a revision of the original FSAR but retains all the applicable information from the original FSAR.

This initial UFSAR is a "clean" document without change bars and revision numbers. The subsequent revisions will have the change indicator and change identification.

Future revisions of the UFSAR will be submitted at least annually and will reflect all the changes up to six months prior to the date of submission.

As a duly authorized officer of Vepco, I hereby certify that the information given in the enclosed UFSAR accurately presents changes made since the previous submittal, necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirement.

Very truly yours,

R. H. Leasburg

Enclosures:

cc: Mr. James P. O'Reilly (w/o enclosures)
Regional Administrator
Region II

S00FWD01

Intentionally Blank

LIST OF EFFECTIVE PAGES

— VOLUME I —

General Table of Contents
(Repeated in each volume)

First Page	Last Page	Revision
TOC-i	TOC-viii	Revision 55 - 09/28/23

Foreword

First Page	Last Page	Revision
1	6	Revision 55 - 09/28/23

List of Effective Pages

First Page	Last Page	Revision
LEP-1	LEP-6	Revision 55 - 09/28/23

Chapter 1

First Page	Last Page	Revision
1-i	1-vi	Revision 55 - 09/28/23
1.1-1	1.1-4	Revision 55 - 09/28/23
1.2-1	1.2-6	Revision 55 - 09/28/23
1.3-1	1.3-10	Revision 55 - 09/28/23
1.4-1	1.4-40	Revision 55 - 09/28/23
1.5-1	1.5-2	Revision 55 - 09/28/23
1.6-1	1.6-8	Revision 55 - 09/28/23

Chapter 2

First Page	Last Page	Revision
2-i	2-x	Revision 55 - 09/28/23
2.1-1	2.1-36	Revision 55 - 09/28/23
2.2-1	2.2-40	Revision 55 - 09/28/23
2.3-1	2.3-30	Revision 55 - 09/28/23
2.4-1	2.4-66	Revision 55 - 09/28/23
2.5-1	2.5-32	Revision 55 - 09/28/23

LIST OF EFFECTIVE PAGES (CONTINUED)

Chapter 3

First Page	Last Page	Revision
3-i	3-vi	Revision 55 - 09/28/23
3.1-1	3.1-2	Revision 55 - 09/28/23
3.2-1	3.2-12	Revision 55 - 09/28/23
3.3-1	3.3-26	Revision 55 - 09/28/23
3.4-1	3.4-34	Revision 55 - 09/28/23
3.5-1	3.5-58	Revision 55 - 09/28/23
3.6-1	3.6-6	Revision 55 - 09/28/23

Chapter 4

First Page	Last Page	Revision
4-i	4-vi	Revision 55 - 09/28/23
4.1-1	4.1-40	Revision 55 - 09/28/23
4.2-1	4.2-44	Revision 55 - 09/28/23
4.3-1	4.3-22	Revision 55 - 09/28/23
4.4-1	4.4-10	Revision 55 - 09/28/23

— VOLUME II —

Chapter 5

First Page	Last Page	Revision
5-i	5-iv	Revision 55 - 09/28/23
5.1-1	5.1-2	Revision 55 - 09/28/23
5.2-1	5.2-38	Revision 55 - 09/28/23
5.3-1	5.3-20	Revision 55 - 09/28/23
5.4-1	5.4-54	Revision 55 - 09/28/23
5.5-1	5.5-6	Revision 55 - 09/28/23

Chapter 6

First Page	Last Page	Revision
6-i	6-iv	Revision 55 - 09/28/23
6.1-1	6.1-6	Revision 55 - 09/28/23
6.2-1	6.2-58	Revision 55 - 09/28/23
6.3-1	6.3-34	Revision 55 - 09/28/23

LIST OF EFFECTIVE PAGES (CONTINUED)

Chapter 7

First Page	Last Page	Revision
7-i	7-vi	Revision 55 - 09/28/23
7.1-1	7.1-4	Revision 55 - 09/28/23
7.2-1	7.2-52	Revision 55 - 09/28/23
7.3-1	7.3-16	Revision 55 - 09/28/23
7.4-1	7.4-26	Revision 55 - 09/28/23
7.5-1	7.5-34	Revision 55 - 09/28/23
7.6-1	7.6-6	Revision 55 - 09/28/23
7.7-1	7.7-10	Revision 55 - 09/28/23
7.8-1	7.8-4	Revision 55 - 09/28/23
7.9-1	7.9-4	Revision 55 - 09/28/23
7.10-1	7.10-2	Revision 55 - 09/28/23
7.11-1	7.11-2	Revision 55 - 09/28/23

Chapter 8

First Page	Last Page	Revision
8-i	8-ii	Revision 55 - 09/28/23
8.1-1	8.1-2	Revision 55 - 09/28/23
8.2-1	8.2-4	Revision 55 - 09/28/23
8.3-1	8.3-6	Revision 55 - 09/28/23
8.4-1	8.4-10	Revision 55 - 09/28/23
8.5-1	8.5-10	Revision 55 - 09/28/23
8.6-1	8.6-2	Revision 55 - 09/28/23

— VOLUME III —

Chapter 9

First Page	Last Page	Revision
9-i	9-xii	Revision 55 - 09/28/23
9.1-1	9.1-42	Revision 55 - 09/28/23
9.2-1	9.2-20	Revision 55 - 09/28/23
9.3-1	9.3-10	Revision 55 - 09/28/23
9.4-1	9.4-30	Revision 55 - 09/28/23
9.5-1	9.5-10	Revision 55 - 09/28/23
9.6-1	9.6-16	Revision 55 - 09/28/23
9.7-1	9.7-10	Revision 55 - 09/28/23
9.8-1	9.8-8	Revision 55 - 09/28/23

LIST OF EFFECTIVE PAGES (CONTINUED)

Chapter 9 (continued)

First Page	Last Page	Revision
9.9-1	9.9-16	Revision 55 - 09/28/23
9.10-1	9.10-50	Revision 55 - 09/28/23
9.11-1	9.11-6	Revision 55 - 09/28/23
9.12-1	9.12-18	Revision 55 - 09/28/23
9.13-1	9.13-18	Revision 55 - 09/28/23
9.14-1	9.14-6	Revision 55 - 09/28/23
9A-i	9A-ii	Revision 55 - 09/28/23
9A-1	9A-22	Revision 55 - 09/28/23
9B-i	9B-ii	Revision 55 - 09/28/23
9B-1	9B-16	Revision 55 - 09/28/23
9C-i	9C-ii	Revision 55 - 09/28/23
9C-1	9C-6	Revision 55 - 09/28/23

Chapter 10

First Page	Last Page	Revision
10-i	10-iv	Revision 55 - 09/28/23
10.1-1	10.1-2	Revision 55 - 09/28/23
10.2-1	10.2-6	Revision 55 - 09/28/23
10.3-1	10.3-54	Revision 55 - 09/28/23

Chapter 11

First Page	Last Page	Revision
11-i	11-vi	Revision 55 - 09/28/23
11.1-1	11.1-2	Revision 55 - 09/28/23
11.2-1	11.2-40	Revision 55 - 09/28/23
11.3-1	11.3-36	Revision 55 - 09/28/23
11A-i	11A-ii	Revision 55 - 09/28/23
11A-1	11A-28	Revision 55 - 09/28/23

Chapter 12

First Page	Last Page	Revision
12-i	12-ii	Revision 55 - 09/28/23
12.1-1	12.1-2	Revision 55 - 09/28/23
12.2-1	12.2-4	Revision 55 - 09/28/23
12.3-1	12.3-2	Revision 55 - 09/28/23

LIST OF EFFECTIVE PAGES (CONTINUED)

Chapter 12 (continued)

First Page	Last Page	Revision
12.4-1	12.4-2	Revision 55 - 09/28/23
12.5-1	12.5-2	Revision 55 - 09/28/23
12.6-1	12.6-2	Revision 55 - 09/28/23
12.7-1	12.7-2	Revision 55 - 09/28/23
12.8-1	12.8-2	Revision 55 - 09/28/23

Chapter 13

First Page	Last Page	Revision
13-i	13-ii	Revision 55 - 09/28/23
13.1-1	13.1-12	Revision 55 - 09/28/23
13.2-1	13.2-4	Revision 55 - 09/28/23
13.3-1	13.3-10	Revision 55 - 09/28/23
13.4-1	13.4-4	Revision 55 - 09/28/23
13.5-1	13.5-24	Revision 55 - 09/28/23

— VOLUME IV —

Chapter 14

First Page	Last Page	Revision
14-i	14-xx	Revision 55 - 09/28/23
14.1-1	14.1-6	Revision 55 - 09/28/23
14.2-1	14.2-134	Revision 55 - 09/28/23
14.3-1	14.3-80	Revision 55 - 09/28/23
14.4-1	14.4-20	Revision 55 - 09/28/23
14.5-1	14.5-136	Revision 55 - 09/28/23
14A-i	14A-ii	Revision 55 - 09/28/23
14A-1	14A-4	Revision 55 - 09/28/23
14B-i	14B-ii	Revision 55 - 09/28/23
14B-1	14B-78	Revision 55 - 09/28/23

Chapter 15

First Page	Last Page	Revision
15-i	15-viii	Revision 55 - 09/28/23
15.1-1	15.1-4	Revision 55 - 09/28/23
15.2-1	15.2-26	Revision 55 - 09/28/23
15.3-1	15.3-2	Revision 55 - 09/28/23

LIST OF EFFECTIVE PAGES (CONTINUED)

Chapter 15 (continued)

First Page	Last Page	Revision
15.4-1	15.4-6	Revision 55 - 09/28/23
15.5-1	15.5-70	Revision 55 - 09/28/23
15.6-1	15.6-20	Revision 55 - 09/28/23
15.7-1	15.7-2	Revision 55 - 09/28/23
15A-i	15A-ii	Revision 55 - 09/28/23
15A-1	15A-50	Revision 55 - 09/28/23

Chapter 16

First Page	Last Page	Revision
16-i	16-ii	Revision 55 - 09/28/23
16.1-1	16.1-2	Revision 55 - 09/28/23
16.2-1	16.2-2	Revision 55 - 09/28/23

Chapter 17

First Page	Last Page	Revision
17-1	17-2	Revision 55 - 09/28/23

Chapter 18

First Page	Last Page	Revision
18-i	18-vi	Revision 55 - 09/28/23
18-1	18-40	Revision 55 - 09/28/23

Surry Power Station
Updated Final Safety Analysis Report

Chapter 1

Chapter 1: Introduction and Summary
Table of Contents

Chapter 1: Introduction and Summary
Table of Contents (continued)

Chapter 1: Introduction and Summary
Table of Contents (continued)

Chapter 1: Introduction and Summary
Table of Contents (continued)

Chapter 1: Introduction and Summary

List of Tables

Intentionally Blank

CHAPTER 1 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

This FSAR supports the operation of two similar nuclear power units, designated as Surry Power Station Units 1 and 2, constructed on a site situated on Gravel Neck and adjacent to the James River in Surry County, Virginia, pursuant to the construction permit issued by the Commission.

Each unit includes a pressurized water reactor (PWR) nuclear steam supply system and turbine generator furnished by Westinghouse Electric Corporation, similar in design concept to several projects licensed by the Commission. The balance of each unit was designed by Vepco, with the assistance of its agent, Stone & Webster Engineering Corporation.

Each reactor unit was designed for a warranted power output of 2441 MWt, with an equivalent warranted gross electrical output of 822.6 MWe. However, the nominal core power rating for each unit is 2587 MWt. All steam and power conversion equipment, including the turbine generator, has been designed on the basis of this higher thermal output and has the capability to generate a maximum calculated gross output of 885 MWe. The engineered safeguards systems and the containment are designed and evaluated for operation at this higher power level, which is used in the analysis of all postulated incidents in this report that have offsite consequences.

Unit 1 achieved commercial operation in December 1972 and Unit 2 in May 1973. In 2010, both units were uprated to a core power output of 2587 MWt (corresponding to a nuclear steam supply system power rating of 2599 MWt).

The remainder of Chapter 1 of this report summarizes the principal design features and safety criteria of the nuclear units by emphasizing the similarities and differences with respect to other pressurized water nuclear power plants at other sites.

Chapter 2 contains a description and evaluation of the Surry site and its environs and demonstrates the suitability of the site for reactors of the size and type described. Chapters 3 and 4 describe the reactor and the reactor coolant system, and Chapters 5 and 15 describe the containment structure and related systems. Chapters 7 through 11 describe the other auxiliary systems. Chapters 5, 6, 7, 8, and 9 include descriptions of the various systems directly related to safeguards. Chapter 12 reviews Vepco's organization and technical competence, associated contractors and consultants, and information relating to station organization and personnel training. Chapter 13 describes Vepco's approach to initial tests and operation. Chapter 14 relates to safety evaluation; it summarizes the analyses that demonstrate the adequacy of the reactor protection system, the containment system, and the engineered safeguards system, and shows that the consequences of various postulated incidents are within the guidelines suggested in the Commission's regulation 10 CFR 100, 10 CFR 50.67, or Regulatory Guide 1.183 (RG 1.183).

Chapter 17 describes the quality assurance program for the operational phase of Vepco's nuclear power stations. Chapter 18 describes the existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) through the subsequent period of extended operation and activities credited in support of the subsequent renewed operating licenses. The inclusion of Chapter 18 into the UFSAR is a condition of the subsequent renewed operating licenses. This final safety analysis report has been prepared using the AEC publication *A Guide for the Organization and Contents of Safety Analysis Reports* as a guide. Refinements may be made from time to time through amendments to this report.

With respect to the numbers, graphs, and drawings included within this report, it should be understood that normal tolerance permitted by good engineering practice is intended. Where operating parameters are unusually important, it is acknowledged that such items are included in the Technical Specifications, the adoption of which is a condition of the operating license.

1.1.1 Design Highlights

The design of the Surry Power Station is based upon concepts that have been developed and successfully applied in the construction of other PWR systems. In subsequent paragraphs, certain design features of the Surry Power Station are indicated that represent slight variations or extrapolations from other units approved for operation, such as H. B. Robinson 2 (Docket 50-261) and Indian Point 3 (Docket 50-286).

1.1.2 Power Level

The nominal power rating for each unit of the Surry Power Station is set at 2587 MWt. Site and engineered safeguards evaluation has been performed for a reactor thermal output of 2587 MWt, which corresponds to the maximum calculated nominal rating of the turbine generator. In 1995, a 2546-MWt power rating was achieved by about a 4.3% increase in the average reactor heat flux over the 2441-MWt rating established for initial operation. An additional 1.6% increase to 2587 MWt was included in a license amendment issued by the NRC in Reference 2 in response to Reference 1.

1.1.3 Reactor Coolant Loops

The reactor coolant system for each unit consists of three loops, each loop having components (steam generator, pumps, and piping) similar to those at Indian Point Unit 2, except that each of the Surry units has two reactor coolant loop stop valves and a bypass valve in each loop.

1.1.4 Peak Specific Power

The operation of the initial core cycle at 2441 MWt yielded a maximum steady-state peak specific power of 17.3 kW/ft and a corresponding peak power of 19.4 kW/ft for the 112% overpower condition. These values were justified by the results of incore experiments by Westinghouse and others at these and higher specific power ratings. These ratings were lower than the corresponding conditions for Indian Point Unit 2, which were 18.4 kW/ft steady-state and 20.6 kW/ft overpower, and which were a result of lower design hot-channel factors.

1.1.5 Fuel Clad

The fuel rod design for each unit uses Zircaloy-4, ZIRLO, or Optimized ZIRLO as a clad material. Zircaloy-4 was proven successful in the Carolinas-Virginia Tube Reactor (CVTR) and Saxon reactors, in Yankee (Rowe), test assemblies, and was subsequently used in many Westinghouse reactors. ZIRLO was later introduced and used in most Westinghouse PWR fuel. Optimized ZIRLO has been irradiated in lead assemblies which include Millstone Unit 3, V. C. Summer, and South Texas. Optimized ZIRLO has been introduced in reload batch quantities at Arkansas Nuclear One Unit 2 and Waterford Unit 3.

1.1.6 Fuel Assembly Design

The fuel assembly incorporated the rod cluster control concept in a canless 15 x 15 fuel and control rod array using grids to provide support for the fuel rods. Extensive out-of-pile tests have been performed on this concept, successful in-pile tests have been performed in the Saxton reactor, and operating experience is available from the San Onofre, Connecticut Yankee, and other similar plants. Prior to the introduction of Surry Improved Fuel (SIF) for both units, all grids were made of Inconel. Beginning with SIF, all intermediate spacer grids will be made of either Zircaloy or ZIRLO.

1.1.7 Moderator Temperature Coefficient of Reactivity

Burnable poison rods are used in the reactor unit to provide a negative moderator temperature coefficient at cycle start-up. As the fuel in the core is depleted and the boron shim concentration is decreased, the moderator temperature coefficient becomes more negative.

1.1.8 Containment

The reactor containment concept is based on the use of a reinforced-concrete container structure similar to that of the Connecticut Yankee Atomic Power Plant, but the containment is maintained at subatmospheric pressure during normal operation. Following the postulated loss-of-coolant accident (LOCA) described in Chapter 14, the containment peak pressure would be reduced to subatmospheric by the use of redundant chemical spray cooling systems, thereby positively terminating outleakage to the environment within 1 hour after the initiation of the accident assuming the most limiting single failure, i.e., loss of emergency power to one train of spray systems. These original design criteria were modified in conjunction with the analyses for implementation of the alternative source term. The modified criteria require that, following the

LOCA, the containment pressure be less than 2.0 psig within 1 hour and less than 0.0 psig within 6 hours. The radiological consequences analysis demonstrates acceptable results provided the containment pressure does not exceed 2.0 psig for the interval from 1 to 6 hours following the Design Basis Accident. Beyond 6 hours, containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

1.1.9 Xenon Oscillations

Ex-core instrumentation is provided to obtain necessary information concerning power distribution. This instrumentation is adequate to enable the operator to monitor and control xenon-induced power oscillations. Extensive analysis, with confirmation of methods by special transient experiments at Haddam Neck, has shown that any induced radial or diametral xenon transients would die away naturally. A full discussion of xenon stability control can be found in WCAP 7208-L (1968), *Power Distribution Control of Westinghouse Pressurized Water Reactors*, Westinghouse proprietary.

1.1 REFERENCES

1. Letter from L.N. Hartz (Dominion) to USNRC, Virginia Electric and Power Company (Dominion), *Surry Power Station Units 1 and 2, License Amendment Request, Measurement Uncertainty Recapture Power Uprate, ML100320264*, Serial No. 09-223, January 27, 2010.
2. Letter from Karen Cotton (NRC) to David A. Heacock (VEPCO), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Re: Measurement Uncertainty Recapture Power Uprate (TAC Nos. ME3293 and ME3294), ML101750002*, Dominion Serial No. 10-580, September 24, 2010.

SUMMARY

0.0.1 General

Each unit at the Surry Power Station incorporates a closed-cycle pressurized water nuclear steam supply system, a turbine generator, and their necessary auxiliaries. Radioactive waste disposal systems, a fuel handling system, and all auxiliaries, structures, and other onsite facilities required for a complete and operable nuclear power station are also provided. The general arrangement of the units is shown in the site plan, Figure 15.1-1, and the plot plan, Reference Drawing 1.

0.0.2 Structures

The major structures are the reactor containments, auxiliary building, fuel building, turbine building, and service building, which includes the main control area. General layouts of the reactor containment for Unit 1, the auxiliary building, and the fuel building, showing interior arrangements, are given on Reference Drawings 2 through 14.

Each reactor containment is a steel-lined, reinforced-concrete cylinder with a hemispherical dome and a flat, reinforced-concrete foundation mat. Each containment is designed to withstand the internal pressure accompanying the hypothetical design-basis incident, is virtually leaktight, and provides adequate radiation shielding for both normal operation and design-basis accident (DBA) conditions. Whenever at subatmospheric pressure, there is no outleakage of activity from the containment structure. The seismic criteria used in the design of the structures and equipment in the station are described in Section 2.5. The maximum horizontal ground acceleration for design purposes is 0.07g. The design-basis maximum horizontal ground acceleration is assumed to be 0.15g. Dampening at these accelerations has been assumed to be 5% and 10%, respectively. Vertical acceleration is two-thirds of the horizontal acceleration and is considered to act simultaneously with the horizontal acceleration.

0.0.3 Nuclear Steam Supply System

The nuclear steam supply system for each unit consists of a pressurized water reactor, a reactor coolant system, and associated auxiliary systems. The reactor coolant system is arranged as three closed reactor coolant loops connected in parallel to the reactor vessel, each containing a reactor coolant pump, isolation and bypass valves, piping, and a steam generator. An electrically heated pressurizer is connected to one of the loops.

Each reactor core includes uranium dioxide pellets, enclosed in zirconium alloy tubes with welded end plugs, as fuel. The tubes are supported in assemblies by structures of grids and there are suitable end pieces for the support of the assembled rods and restraint of abnormal axial movement. The mechanical control rod assemblies consist of clusters of stainless-steel-clad absorber rods that are guided by tubes located within the fuel assembly. The core consists of 157 of these fuel assemblies loaded in varying enrichments. Originally, an out-in fuel management approach was used in core design. Fresh, high-enrichment fuel was introduced into the core outer region. At the next refueling, it was moved to the core inner region where it was intermingled with fuel moved from the outer region during the previous refueling. Two refuelings later, the original high-enrichment fuel was discharged to spent-fuel storage. Currently a low leakage type of fuel management is employed which places burned fuel assemblies on the core periphery and intermingles the fresh fuel assemblies with previously burned assemblies in the core's interior regions.

The steam generators are vertical U-tube units containing Inconel tubes. Integral separating equipment reduces the moisture content of the steam at the turbine throttle to 0.25% or less.

The reactor coolant pumps are vertical, single-stage, centrifugal pumps equipped with controlled-leakage shaft seals.

The reactor coolant loop stop and bypass valves are motor-operated gate valves that are remotely controlled from the control room. These valves permit any loop to be isolated from the reactor vessel.

Nuclear auxiliary systems are provided to perform the following functions:

1. Accommodate reactor coolant system water makeup requirements.
2. Purify reactor coolant water.
3. Introduce chemicals for corrosion inhibition.
4. Introduce and remove chemicals for reactivity control.
5. Cool system components.
6. Remove residual heat during a portion of the reactor cooling period and also when the reactor is shut down.
7. Cool the spent-fuel pool water.
8. Permit the sampling of reactor coolant water.
9. Provide for emergency safety injection.
10. Vent and drain the reactor coolant system and the auxiliary systems.
11. Provide emergency containment spray.
12. Provide emergency chemical containment spray.
13. Maintain a subatmospheric containment pressure.
14. Provide containment ventilation and cooling.
15. Dispose of liquid and gaseous wastes, and provide for the disposal of solid wastes.

0.0.4 Reactor and Station Controls

The reactor is controlled by a coordinated combination of chemical shim and mechanical control rod assemblies. The control system permits the unit to accept step load increases of 10% and ramp load increases of 5% per minute over a load range of 15% to 100% power under normal operating conditions, subject to xenon limitations.

The control of both the reactor and turbine generator for each unit is accomplished from the control room and is supervised by licensed operators.

0.0.5 Waste Disposal System

The waste disposal system provides all equipment necessary to collect, process, and prepare for disposal of all radioactive liquid, gaseous, and solid waste produced as a result of station operation. The waste disposal system is capable of handling the wastes produced by both units as a result of station operation.

Liquid wastes are collected and processed by evaporation, reverse osmosis, and/or ion exchange. Processed liquid is analyzed before discharge into the river. Discharges are maintained below limits established by 10 CFR 20 or other appropriate regulations. Non-combustible and combustible solid wastes can be sorted, shredded, baled or drummed consistent with applicable offsite processing or disposal requirements. They are shipped from the site for ultimate disposal at an authorized location.

Gaseous wastes are diluted and discharged to the environment with a yearly average radioactivity level within the limits set forth in 10 CFR 20.

0.0.6 Fuel Handling Systems

The reactor is refueled with equipment designed to handle spent fuel under water from the time it leaves a reactor vessel until it is placed in a cask for shipment from the site. Spent fuel is transferred under water, which provides an optically transparent radiation shield and a reliable source of coolant for removal of residual heat.

0.0.7 Turbines and Auxiliaries

Each turbine is a tandem-compound, three-element, 1800-rpm unit having 57-inch, last-stage exhaust blading in the low-pressure elements. Four combination moisture separators-reheaters are employed to dry and superheat the steam between the high-pressure and low-pressure turbine cylinders for each unit. A single-pass, deaerating surface condenser installed in two sections, two 100%-capacity steam jet air ejectors, three 50%-capacity condensate pumps, two 50%-capacity steam generator feedwater pumps, three auxiliary feedwater pumps, and six stages of feedwater heating are provided.

0.0.8 Electrical Systems

The main generator for each unit is an 1800-rpm, 22-kV, three-phase, 60-cycle, hydrogen inner-cooled unit. A main step-up transformer delivers power to the high-voltage switchyard.

The station service power distribution system for each unit consists of station service transformers, 4160V and 480V switchgear and buses, and 480V motor control centers. The normal source of station service power is the main generator, while the reserve station service transformers provide an alternate source via the switchyard. The emergency power distribution system consists of 4160V and 480V switchgear and buses, 480V motor control centers, 120V ac vital buses, and 125V dc batteries and equipment. The emergency buses are normally powered from the switchyard via the three reserve station service transformers.

Emergency power is supplied by alternate sources, including one emergency diesel-driven generator for each unit and a third diesel-driven generator shared by both units. Each diesel-driven generator is capable of operating post-incident containment recirculation spray pumps as well as charging pumps and low-head safety injection pumps to ensure an acceptable containment pressure transient during the design-basis accident.

1.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FY-1D	Plot Plan
2.	11448-FM-1A	Machine Location: Reactor Containment, Elevation 47'- 4"
3.	11448-FM-1B	Machine Location: Reactor Containment, Elevation 18'- 4"
4.	11448-FM-1C	Machine Location: Reactor Containment, Elevation 3'- 6"
5.	11448-FM-1D	Machine Location: Reactor Containment, Elevation 27'- 7"
6.	11448-FM-1E	Machine Location: Reactor Containment; Sections “A-A”, “E-E”, & “Z-Z”
7.	11448-FM-1F	Machine Location: Reactor Containment; Sections “B-B”, “X-X”, & “Y-Y”
8.	11448-FM-1G	Machine Location: Reactor Containment, Sections “C-C” & “D-D”
9.	11448-FM-5A	Arrangement: Auxiliary Building
10.	11448-FM-5B	Arrangement: Auxiliary Building, Unit 1
11.	11448-FM-5C	Arrangement: Auxiliary Building
12.	11448-FM-5D	Arrangement: Auxiliary Building
13.	11448-FM-9A	Arrangement: Fuel Building, Sheet 1
14.	11448-FM-9B	Arrangement: Fuel Building, Sheet 2, Unit 1

Intentionally Blank

1.3 COMPARISON WITH OTHER STATIONS

Table 1.3-1 presents a summary of the design and operating parameters for the Surry Power Station nuclear steam supply systems. The table provides a comparison of these data with the data available from the FSAR of Turkey Point Units 3 and 4, and with the data available from the FSAR of H. B. Robinson Unit 2.

The Turkey Point and H. B. Robinson references were selected because both are closely related technically to the Surry units, and both were reviewed for operating licenses during the same general time frame as the Surry units.

The Surry Power Station units are also generally comparable with the pressurized water reactors at Pacific Gas and Electric Company, Duquesne Light Company, Rochester Gas and Electric Company, and the Tennessee Valley Authority (Sequoyah Units).

Table 1.3-1
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
Thermal and Hydraulic Design Parameters			
Total core heat output	2441 MWt	2200 MWt	2200 MWt
Total core heat output	8331×10^6 Btu/hr	7479×10^6 Btu/hr	7479×10^6 Btu/hr
Heat generated in fuel	97.4%	97.4%	97.4%
Maximum thermal overpower	112%	112%	112%
System operating pressure, nominal	2250 psia	2250 psia	2250 psia
System operating pressure, minimum steady state	2200 psia	2200 psia	2200 psia
DNB ratio at nominal initial rating condition	1.97	1.81	1.81
Minimum DNB ratio for design transients	1.30	1.30	1.30
Coolant flow			
Total flow rate	100.7×10^6 lb/hr	101.5×10^6 lb/hr	101.5×10^6 lb/hr
Effective flow rate for heat transfer	96.2×10^6 lb/hr	97.0×10^6 lb/hr	97.0×10^6 lb/hr
Effective flow area for heat transfer	41.8 ft^2	41.8 ft^2	41.8 ft^2
Average velocity along fuel rods	14.2 ft/sec	14.3 ft/sec	14.3 ft/sec
Average mass velocity	2.31×10^6 lb/hr-ft^2	2.32×10^6 lb/hr-ft^2	2.32×106 lb/hr-ft^2
Coolant temperature (at 100% power)			
Nominal inlet	543°F	546.2°F	546.2°F
Minimum inlet due to instrumentation error and deadband	547°F	550.2°F	550.2°F
Average rise in vessel	62.6°F	55.9°F	55.9°F
Average rise in core	65.5°F	58.3°F	58.3°F
Average in core	577°F	575.4°F	575.4°F
Average in vessel	574°F	574.2°F	574.2°F
Nominal outlet of hot channel	642°F	642°F	642°F

Table 1.3-1 (CONTINUED)
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
Thermal and Hydraulic Design Parameters (continued)			
Average film coefficient	5400 Btu/hr-ft^2-°F	5400 Btu/hr-ft^2-°F	5400 Btu/hr-ft^2-°F
Average film temperature difference	35.0°F	31.8°F	31.8°F
Heat transfer at 100% power			
Active heat transfer surface area	42,460 ft^2	42,460 ft^2	42,460 ft^2
Average heat flux	191,100 Btu/hr-ft^2	171,600 Btu/hr-ft^2	171,600 Btu/hr-ft^2
Maximum heat flux	534,100 Btu/hr-ft^2	554,200 Btu/hr-ft^2	554,200 Btu/hr-ft^2
Average thermal out put	6.2 kW/ft	5.5 kW/ft	5.5 kW/ft
Maximum thermal out put	17.3 kW/ft	17.9 kW/ft	17.9 kW/ft
Maximum clad surface temperature at nominal pressure	657°F	657°F	657°F
Fuel central temperature			
Maximum at 100% power	4,050°F	4,030°F	4,030°F
Maximum at overpower	4,300°F	4,300°F	4,300°F
Thermal output, at maximum overpower	20.6 kW/ft	20.0 kW/ft	20.0 kW/ft
Core Mechanical Design Parameters			
Fuel assemblies			
Design	Canless 15 x 15	Canless 15 x 15	Canless 15 x 15
Rod pitch	0.563 in.	0.563 in.	0.563 in.
Overall dimensions	8.426 x 8.426 in.	8.426 x 8.426 in.	8.426 x 8.426 in.
Fuel weight (as UO_2)	176,200 lb	176,200 lb	176,200 lb
Total weight	226,200 lb	226,200 lb	226,200 lb
Number of grids per assembly	7	7	7

Table 1.3-1 (CONTINUED)
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
Core Mechanical Design Parameters (continued)			
Fuel rods			
Number	32,028	32,028	32,028
Outside diameter	0.422 in.	0.422 in.	0.422 in.
Diametral gap	0.0075/0.0075/0.0085 in.	0.0065 in.	0.0065 in.
Clad thickness	0.0243 in.	0.0243 in.	0.0243 in.
Clad material	Zircaloy-4	Zircaloy	Zircaloy
Fuel pellets			
Material	UO^2 sintered	UO^2 sintered	UO^2 sintered
Density (percent of theoretical)	94, 93, 92	94, 92, 91	94, 92, 91
Diameter	0.3659/0.3659/0.3649 in.	0.3669 in.	0.3669 in.
Length	0.6000 in.	0.6000 in.	0.6000 in.
Control rod assemblies			
Neutron adsorber	5% Cd, 15% In, 80% Ag	5% Cd, 15% In, 80% Ag	5% Cd, 15% In, 80% Ag
Cladding material	SS 304, cold worked	SS 304, cold worked	SS 304, cold worked
Clad thickness	0.019 in.	0.019 in.	0.019 in.
Number of control rod assemblies (full/part length)	48/5	45/8	45/8
Number of rods per assembly	20	20	20
Total rod worth (k per k)	See Table 3.3-3	See Chapter 3 of Turkey Point FSAR	See Chapter 3 of H.B. Robinson FSAR
Core structure			
Core barrel i.d./o.d.	133.875/137.875 in.	133.875/137.875 in.	133.875/137.875 in.
Thermal shield i.d./o.d.	142.625/148.000 in	142.625/148.0 in	142.625/148.0 in

Table 1.3-1 (CONTINUED)
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
	Nuclear Design Data		
Structural characteristics			
Fuel weight (as UO_2)	175,600 lb	176,200 lb	176,200 lb
Clad weight	36,300 lb	36,300 lb	36,300 lb
Core diameter (equivalent)	119.5 in.	119.5 in.	119.5 in.
Core height (active fuel)	144 in.	144 in.	144 in.
Reflector thickness and composition			
Top - water plus steel	10 in.	10 in.	10 in.
Bottom - water plus steel	10 in.	10 in.	10 in.
Side - water plus steel	15 in.	15 in.	15 in.
H_2O/U, unit cell (cold volume ratio)	4.18	4.18	4.18
Number of fuel assemblies	157	157	157
Uranium dioxide rods per assembly	204	204	204
Performance characteristics			
Loading technique	3 region, non-uniform	3 region, non-uniform	3 region, non-uniform
Fuel burnup, MWD/MTU			
Average first cycle	12,600	13,000	13,000
First core average	22,300	24,500	24,500
Feed enrichments, wt.%			
Region 1	1.85	1.85	1.85
Region 2	2.55	2.55	2.55
Region 3	3.10	3.10	3.10

Table 1.3-1 (CONTINUED)
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
Nuclear Design Data (continued)			
Control characteristics			
Effective multiplication (beginning of life), k_{eff}			
Cold, no power, clean	1.176	1.180	1.180
Hot, no power, clean	1.145	1.38	1.38
Hot, full power, Xe and Sm equilibrium	1.090	1.077	1.077
Boron concentrations			
To shut reactor down with no control rod assemblies inserted, clean (k_{eff} = 0.99)			
Cold	1250 ppm	1250 ppm	1250 ppm
Hot	1240 ppm	1210 ppm	1210 ppm
To control at power with no control rod assemblies inserted, clean/equilibrium Xe and Sm	1005 ppm/705 ppm	1000 ppm/670 ppm	1000 ppm/920 ppm
Burnable poison worth, hot	6.9% k/k	7.3% k/k	7.3% k/k
Burnable poison worth, cold	5.3% k/k	5.6% k/k	5.6% k/k
Kinetic characteristics			
Moderator temperature coefficient	$+0.3 \times 10^{-4}$ to -3.5×10^{-4} k/k per °F	$+0.3 \times 10^{-4}$ to -3.5×10^{-4} k/k per °F	10.3×10^{-4} to -3.5×10^{-4} k/k per °F
Moderator pressure coefficient	-0.3×10^{-6} to $+3.5 \times 10^{-6}$ k/k per psi	-0.3×10^{-6} to $+3.4 \times 10^{-6}$ k/k per psi	-0.3×10^{-6} to $+3.5 \times 10^{-6}$ k/k per psi
Moderator density (void) coefficient	–0.1 to +0.3 k/k per g per cm^3	$+0.5 \times 10^{-3}$ to -2.5×10^{-3} k/k per °F	$+0.5 \times 10^{-3}$ to -2.5×10^{-3} k/k per % void
Doppler coefficient	-1×10^{-5} to -1.6×10^{-5} k/k per °F	-1×10^{-5} to -1.6×10^{-5} k/k per °F	-1×10^{-5} to -1.6×10^{-5} k/k per °F

Table 1.3-1 (CONTINUED)
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
Reactor Coolant System—Code Requirements			
Component			
Reactor vessel	ASME III, Class A	ASME III, Class A	ASME III, Class A
Steam generator			
Tube side	ASME III, Class A	ASME III, Class A	ASME III, Class A
Shell side	ASME III, Class C	ASME III, Class C	ASME III, Class C
Pressurizer	ASME III, Class A	ASME III, Class A	ASME III, Class A
Pressurizer relief tank	ASME III, Class C	ASME III, Class C	ASME III, Class C
Pressurizer safety valves	ASME III	ASME III	ASME III
Reactor coolant piping	USAS B31.1	USAS B31.1	USAS B31.1
Principal Design Parameters of the Reactor Coolant System (100%)			
Reactor core heat output	2441 MWt	2200 MWt	2200 MWt
Reactor heat output	8331×10^6 Btu/hr	7479×10^6 Btu/hr	7479×10^6 Btu/hr
Operating pressure	2235 psig	2235 psig	2235 psig
Reactor inlet temperature	543°F	546.2°F	546.2°F
Reactor outlet temperature	605.8°F	602.1°F	602.1°F
Number of loops	3	3	3
Design pressure	2485 psig	2485 psig	2485 psig
Design temperature	650°F	650°F	650°F
Hydrostatic test pressure (cold)	3107 psig	3107 psig	3107 psig
Coolant volume, including total pressurizer	9458 ft^3	9088 ft^3	9088 ft^3
Total reactor flow	265,500 gpm	268,500 gpm	2,68,500 gpm

Table 1.3-1 (CONTINUED)
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
Reactor Design Parameters of the Reactor Vessel			
Material	SA-302 Grade B, low-alloy steel, internally clad with austenitic SS 304	SA-302 Grade B, low-alloy steel, internally clad with austenitic SS 304	SA-302 Grade B, low-alloy steel, internally clad with austenitic SS 304
Design pressure	2485 psig	2485 psig	2485 psig
Design temperature	650°F	650°F	650°F
Operating pressure	2235 psig	2235 psig	2235 psig
Inside diameter of shell	157 in.	155.5 in.	155.5 in.
Outside diameter across nozzles	252 in.	236 in.	236 in.
Overall height of vessel and enclosure head	40 ft. 5 in.	41 ft. 6 in.	41 ft. 6 in.
Minimum clad thickness	5/32 in.	5/32 in.	5/32 in.
Principal Design Parameters of the Steam Generators			
Number of units	3	3	3
Type	Vertical U-tube with integral moisture separator	Vertical U-tube with integral moisture separator	Vertical U-tube with integral moisture separator
Tube material	Inconel	Inconel	Inconel
Shell material	Carbon steel	Carbon steel	Carbon steel
Tube side design pressure	2485 psig	2485 psig	2485 psig
Tube side design temperature	650°F	650°F	650°F
Tube side design flow	33.57×10^6 lb/hr	33.43×10^6 lb/hr	33.93×10^6 lb/hr
Shell side design pressure	1085 psig	1085 psig	1085 psig
Shell side design temperature	600°F	556°F	556°F
Operating pressure, tube side, nominal	2235 psig	2235 psig	2235 psig
Operating pressure, shell side, maximum	1005 psig	1005 psig	1005 psig

Table 1.3-1 (CONTINUED)
COMPARISON OF INITIAL DESIGN PARAMETERS

Design Parameter	Surry Power Station	Turkey Point 3 or 4	H.B. Robinson
Principal Design Parameters of the Steam Generators (continued)			
Maximum moisture at outlet at full load	0.25%	0.25%	0.25%
Hydrostatic test pressure, tube side (cold)	3107 psig	3107 psig	3110 psig
Principal Design Parameters of the Reactor Coolant Pumps			
Number of units	3	3	3
Type	Vertical single-stage mixed flow with bottom suction and horizontal discharge	Vertical single-stage radial flow with bottom suction and horizontal discharge	Vertical single-stage radial flow with bottom suction and horizontal discharge
Design pressure	2485 psig	2485 psig	2485 psig
Design temperature	650°F	650°F	650°F
Operating pressure, nominal	2235 psig	2235 psig	2235 psig
Suction temperature	543°F	546.5°F	546.5°F
Design capacity	88,500 gpm	89,500 gpm	89,500 gpm
Design head	280 ft	260 ft	260 ft
Hydrostatic test pressure (cold)	3107 psig	3107 psig	3107 psig
Motor type	Single-speed ac induction	Single-speed ac induction	Single-speed ac induction
Motor rating	6000 hp	6000 hp	6000 hp
Principal Design Parameters of the Reactor Coolant Piping			
Material	Austenitic SS	Austenitic SS	Austenitic SS
Hot leg, i.d.	29 in.	29 in.	29 in.
Cold leg, i.d.	27.5 in.	27.5 in.	27.5 in.
Between pump and steam generator, i.d.	31 in.	31 in.	31 in.
Design pressure	2485 psig	2485 psig	2485 psig

Intentionally Blank

1.4 COMPLIANCE WITH CRITERIA

The design of the Surry Power Station meets the intent of the criteria as expressed within this section. Following the text of each criterion is a brief discussion specific to that criterion.

1.4.1 Quality Standards

Those systems and components of reactor facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of their consequences are designed, fabricated, and erected in accordance with quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes or standards on design, materials, fabrication, and inspection are used, they are identified. Where adherence to such codes or standards does not suffice to ensure a quality product in keeping with the safety function, they are supplemented or modified as necessary. A showing of sufficiency and applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance levels used is required.

Refer to the response to the criterion in Section 1.4.2.

1.4.2 Performance Standards

Those systems and components of reactor facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of their consequences are designed, fabricated, and erected in accordance with performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects. The design bases so established reflect (a) appropriate consideration of the most severe of these natural phenomena that have been recorded for the site and the surrounding area, and (b) an appropriate margin for withstanding forces greater than those recorded, in view of uncertainties about the historical data and their suitability as a basis for design.

Those features of reactor facilities essential to the prevention of accidents that could affect the public health and safety or to the mitigation of their consequences are designed, fabricated, and erected in conformity with:

1. Quality standards that reflect the importance of the safety function to be performed. Approved design codes are used when appropriate to the nuclear application.
2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena characteristic of the site.

Features of the facility essential to accident prevention and the mitigation of accident consequences are the designs of the fuel, reactor coolant, and containment barriers; the controls and emergency cooling systems whose function is to maintain the integrity of these three barriers;

systems that depressurize the containment following a LOCA; a power supply and essential services; and the components employed to safely convey and store radioactive wastes and spent reactor fuel.

The fuel assembly rod design considers the effect on the zirconium alloy cladding of internal fission gas pressure buildup, thermal expansion, irradiation, and fabrication variations. Core design conditions and cladding material specifications are selected to limit hydrogen absorption during core life to levels that do not affect fuel cladding integrity. To ensure high quality, fuel rod materials are subjected to chemical analysis and tensile tests and the rods receive dimensional inspection, X-ray of welds, ultrasonic tests, and helium leak tests.

Quality standards of material selection, design, fabrication, and inspection governing the above features conform to the applicable provisions of recognized codes and good nuclear practice. The reinforced-concrete reactor containment structures conform to the applicable portions of ACI-318-63.

Further elaboration on quality standards of the reactor containment is given in Chapter 15. Vessels comply with Section III of the ASME Code under the specific classification dictated by their use. The principles of this Code, or equivalent guidelines, are employed where the Code is not strictly applicable but where the safety function calls for an equivalent assurance of quality. In the same manner, piping conforms to the requirements of USAS B31.1.

Particular emphasis is placed on the assurance of quality of each reactor vessel and hence on the acquisition of materials whose properties are uniformly within tolerances appropriate to the application of the design methods of the Code. The fatigue usage factor, derived from an assumed number of thermal cycles that is probably more than four times the number of such cycles actually expected, is less than that at which the propagation of material defects would occur.

The design margin and material surveillance ensure that each vessel is operated well within the ductile range of temperatures when the reactor vessel is operated within established operational limits. Further discussion of quality assurance for the reactor vessels, including the use of vessel irradiation test specimens, is given in Chapter 4.

All piping, components, and supporting structures of each reactor and the safety-related systems are designed to withstand a specified seismic disturbance in excess of that predicted for the site. Station design criteria specify that there is no loss of function of such equipment in the event of the DBA ground acceleration acting in the horizontal and vertical directions simultaneously. The dynamic response of Class I structures to ground acceleration, based on appropriate characteristics of the site foundation soils and on the critical damping of the foundations and structures, is included in the design analysis.

Each reactor containment is defined for seismic purposes as a Class I structure. Structural members have sufficient capacity to accept, without exceeding yield stresses, a combination of normal operating loads, functional loads due to a design-basis accident and the loadings imposed by the maximum wind velocity or the design-basis earthquake (DBE), whichever is larger. The emergency onsite power sources are not subject to interruption due to earthquakes, windstorms, floods, or disturbances in the external power transmission system. Power cabling, motors, and other equipment required for the operation of the engineered safeguards is suitably protected against the effects of the design-basis accident and other severe external environmental conditions, as applicable, to ensure a high degree of confidence in the operability of these systems should they be required.

The reference chapters are as follows:

Title	Chapter
Site	2
Reactor	3
Reactor Coolant System	4
Containment System	5
Engineered Safeguard	6
Instrumentation and Control	7
Electrical Systems	8
Auxiliary and Emergency Systems	9
Radioactive Wastes and Radiation Protection	11
Structures and Construction	15

1.4.3 Fire Protection

The reactor facility is designed (1) to minimize the probability of events such as fires and explosions and (2) to minimize the potential effects of such events on safety. Non-combustible and fire-resistant materials are used whenever practical throughout the facility, particularly in areas containing critical portions of the facility such as the containment, the control room, and components of engineered safeguards.

Fire or explosions occurring within the reactor facility are avoided because of the inherent preventive features in the station design.

Waste hydrogen gas is collected in the waste gas decay tanks. The oxygen content of the tank is limited administratively to 2% by volume. The oxygen content by volume may be diluted to a concentration below its upper limit by the addition of nitrogen to the tank (preferred - to maximize radioactivity decay time of waste gases) or by performing a release. Systems processing hydrogen-oxygen mixtures that are potentially hazardous conform to the National Electrical Code for Areas of Class I, Division 2, Group B. All spark-producing devices near the waste hydrogen equipment are explosion-proof.

The containment and other structures containing safe-shutdown equipment are of fire resistive or non-combustible construction and contain mostly non-combustible equipment. Atmospheric conditions inside the containment are not of an explosive nature.

The control room is of non-combustible construction and is isolated from surrounding areas by heavy concrete shielding. The control room atmosphere is not explosive and is maintained under positive pressure by its air conditioning system.

The references chapters are as follows:

Title	Chapter
Reactor Coolant System	4
Containment System	5
Auxiliary and Emergency System	9
Radioactive Wastes and Radiation Protection	11

1.4.4 Sharing of Systems

Reactor facilities do not share systems or components unless it is shown that safety is not impaired by the sharing.

The facilities that have shared systems or components are tabulated in Section 1.5, with references to sections containing specific design details.

No impairment of the safety of the reactor facilities is caused by the sharing of any of these systems, and in certain instances such sharing enhances system reliability.

1.4.5 Records Requirements

Records of the design, fabrication, and construction of essential components of the plant are maintained by the reactor operator or are under Vepco’s control throughout the life of the reactor.

Records of the design, fabrication, and construction of essential components are maintained during the life of the unit and are available to Vepco. Chapter 17 includes a discussion of this matter. Records of all tests performed and test procedures used are kept by Vepco for the life of the unit.

The reference chapter is as follows:

Title	Chapter
Quality Assurance (Topical Report)	17

1.4.6 Reactor Core Design

The reactor core with its related controls and protection systems is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits that have been stipulated and justified. The core and related auxiliary system designs provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations that can be anticipated.

The reactor core with its related control and protection system is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. The core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of reactor coolant flow, trip of the turbine generator, loss of normal feedwater, and loss of all offsite power.

The reactor control and protection instrumentation is designed to actuate a reactor trip for any anticipated combination of unit conditions when necessary to ensure a minimum departure from nucleate boiling ratio (DNBR) equal to or greater than the design DNBR limit (Section 3.2.3) and fuel center temperatures below the melting point of uranium dioxide.

The references chapters are as follows:

Title	Chapter
Reactor	3
Instrumentation and Control	7
Safety Analysis	14

1.4.7 Suppression of Power Oscillations

The design of the reactor core with its related controls and protection systems ensures that power oscillations, the magnitude of which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed.

The design of the reactor core and related protection systems ensures that power oscillations that could cause fuel damage in excess of acceptable limits are not possible or can be readily suppressed.

The potential for possible spatial oscillations of power distribution for this core are reviewed as part of the core stability evaluation described in Section 1.6. Ex-core instrumentation is provided to obtain necessary information concerning axial and azimuthal power distributions. This instrumentation is adequate to enable the operator to monitor and control xenon-induced oscillations. Based on the deviations detected by the long ion chambers, provisions in the reactor control and protection system reduce trip setpoints and if necessary initiate load runback to maintain margin to departure from nucleate boiling as a result of these potential oscillations in power distribution. Incore instrumentation is used to periodically calibrate and verify the information provided by the ex-core instrumentation.

The general conclusion based on experimental results from SENA and San Onofre is that the ex-core instruments do give an accurate indication of the fact that power redistribution is taking place. This has been confirmed by a comparison with incore instrumentation results.

The temperature coefficient in the power operating range was maintained zero or negative by the inclusion of burnable poison shims in the initial core loading. Burnable poison shims can also be used in subsequent core loadings if necessary.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Instrumentation and Control	7

1.4.8 Overall Power Coefficient

The reactor is designed so that the overall power coefficient in the power operating range is not positive.

The overall power coefficient is negative under normal operating conditions throughout core life.

The reference chapter is as follows:

Title	Chapter
Reactor	3

1.4.9 Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary is designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime.

The reactor coolant system, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation or anticipated system interactions, and to remain within the applicable code stress limits.

The fabrication of the components that constitute the pressure-retaining boundary of the reactor coolant system is carried out in strict accordance with the applicable codes. In addition, there are areas where equipment specifications for reactor coolant system components are more restrictive than applicable codes.

The materials of construction of the pressure-retaining boundary of the reactor coolant system are protected by the control of coolant chemistry so as to prevent corrosion phenomena that might otherwise reduce the system structural integrity during its service lifetime.

The reference chapter is as follows:

Title	Chapter
Reactor Coolant System	4

1.4.10 Containment

Containment is provided. The containment structure is designed to sustain the initial effects of gross equipment failures, such as a large coolant boundary break, without loss of required integrity, and, together with other engineered safeguards as may be necessary, to retain for as long as the situation requires the functional capability to protect the public.

A reinforced-concrete, steel-lined containment structure operating at subatmospheric pressure encloses the entire reactor coolant system. It is designed to sustain, without loss of required integrity, all effects of gross equipment failures up to and including the rupture of the largest pipe in the reactor coolant system. Engineered safeguards, which consist of safety injection systems and containment depressurization systems, serve to cool the reactor core and return the containment to subatmospheric pressure and maintain it at subatmospheric pressure for as long as the situation requires. The containment and its associated engineered safeguards exceed the required functional capability of protecting the public from the consequences of gross equipment failures, since they provide for a rapid termination of the effects of the event.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6

1.4.11 Control Room

The facility is provided with a control room from which actions to maintain the safe operation of the plant can be controlled.

Radiation protection is provided to permit access, even under accident conditions, to equipment in the control room or other areas as necessary to shut down and maintain safe control of the facility without radiation exposures of personnel in excess of 10 CFR 20 limits. It is possible to shut the reactor down and maintain it in a safe condition if access to the control room is lost through fire or other causes.

The control room is located at grade level in the service building. All safety-related switchgear, motor-generator sets, auxiliary instrument areas, battery rooms, and communications equipment are located in the basement of the service building. Sufficient shielding, distance, and containment integrity are provided to ensure that under postulated accident conditions during occupancy of the control room, control room personnel shall not be subjected to doses that, in the aggregate, would exceed the limits in 10 CFR 50.67. Emergency air-conditioning equipment is provided within the envelope of the shielded control room and associated portions of the basement, collectively called the control and relay room area. The control room is provided with the switchyard control panel, electrical recording panels, dc distribution panels, and a control panel for the operation of the diesel-generator system. The control panels contain those instruments and controls necessary for the operation of station and unit systems such as the reactor and its auxiliary systems, the turbine generator, and the steam and power conversion systems. Loading from the various station electrical distribution boards, such as the start-up boards, shutdown boards, and motor control centers, is accomplished from the station control panels.

The control room is common to the two units and is continuously occupied by qualified operating personnel under all operating and accident conditions.

In the event that access to the control room is restricted, either local control stations or the manual operation of critical components within the main control area can be used to effect hot shutdown from outside the control room.

The reference chapters are as follows:

Title	Chapter
Instrumentation and Control	7
Auxiliary and Emergency Systems	9

1.4.12 Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables.

Instrumentation and controls essential to avoid undue risk to the health and safety of the public are provided to monitor and maintain neutron flux, primary coolant pressure and temperature, and control rod assembly positions within prescribed operating ranges.

The non-nuclear-regulating process and containment instrumentation measures temperatures, pressure, flow, and levels in the reactor coolant system, main steam system, containment, and auxiliary systems. Process variables required on a continuous basis for the start-up, operation, and shutdown of the unit are indicated, recorded, and controlled from the control room, into which access is supervised. The quantity and types of process instrumentation provided ensure the safe and orderly operation of all systems and processes over the full operating range of the station.

Reference chapters are as follows:

Title	Chapter
Engineered Safeguards	6
Instrumentation and Control	7

1.4.13 Fission Process Monitors and Controls

Means are provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in the reactivity of the core.

Nuclear instrumentation is provided to monitor reactor power from the source range through the intermediate range and power range up to 120% of full power. The system provides indication, control, and alarm signals for reactor operation and protection.

The operational status of the reactor is monitored from the control room. When the reactor is subcritical, the relative reactivity status is continuously monitored and indicated by proportional counters located in instrument wells in the neutron shield tank adjacent to the reactor vessel. Two source detector channels supply information on multiplication while the reactor is subcritical.

When the reactor is critical, means for showing the relative reactivity status of the reactor are provided by control rod assembly bank positions displayed in the control room. The position of the control rod assembly banks is directly related to the reactivity status of the reactor when at power, and any unexpected change in the position of the control rod assembly banks under automatic control or any change in the coolant temperature under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. Periodic sampling to determine the boric acid concentration provides a long-term means of following reactivity status.

The reference chapter is as follows:

Title	Chapter
Instrumentation and Control	7

1.4.14 Core Protection Systems

Core protection systems, together with associated equipment, are designed to prevent or to suppress conditions that can result in exceeding acceptable fuel damage limits.

The reactor protection system receives, from unit instrumentation, signals that are indicative of an approach to an unsafe operating condition. This system then actuates alarms, prevents control rod assembly motion, initiates load runback, and/or opens the trip breakers causing the insertion of the control rod assemblies, depending on the severity of the condition. The allowable operating range within reactor trip settings includes combinations of power, temperature, and pressure that do not result in the occurrence of a departure from nucleate boiling with all reactor coolant pumps in operation.

The reference chapter is as follows:

Title	Chapter
Instrumentation and Control	7

1.4.15 Engineered Safeguards Protection Systems

Protection systems are provided for sensing accident situations and initiating the operation of necessary engineered safeguards.

Instrumentation and controls provided for the protection systems are designed to trip the reactor when necessary to prevent or limit fission product release from the core and to limit energy release, to cause closure of containment isolation valves, and to control the operation of engineered safeguards equipment.

Additional tripping functions such as a high pressurizer pressure trip, low pressurizer pressure trip, high pressurizer water-level trip, loss-of-coolant-flow trip, steam and feedwater flow mismatch trip, steam generator low-low water-level trip, turbine trip, safety injection trip, neutron source and intermediate range trips, and manual trip are provided to back up the primary tripping functions for specific accident conditions and mechanical failures.

The passive accumulators of the safety injection system do not require signal or power sources to perform their function. The actuation of the active portion of this system is obtained from low-low pressurizer pressure, high containment pressure, steam header to steam line pressure differential, high steam flow coincident with a low T_{avg} or low steam line pressure signals, and manual actuation.

The containment isolation system provides the means for isolating various pipes passing through the containment walls as required to prevent the release of radioactivity to the outside environment in the event of a LOCA. The actuation of containment isolation is by coincident and redundant containment high-pressure signals.

Reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6
Instrumentation and Control	7

1.4.16 Monitoring Reactor Coolant Pressure Boundary

Means are provided for monitoring the reactor coolant pressure boundary to detect leakage.

Means of detecting leakage from the reactor coolant system are provided by measuring the airborne activity of the containment and indicating changes in makeup requirements and containment sump levels.

The sampling system for each unit contains two steam generator blowdown sample monitors in parallel. They are used for monitoring the liquid phase of the steam generators for radioactivity indicative of a primary-to-secondary system leak. Samples from each of the three steam generator bottoms are mixed in two common headers with each header going to a gamma scintillation counter mounted in an in-line liquid sampler. In general, both monitors are used continuously. Either monitor can be used to monitor any individual steam generator that is known to be leaking. In the event that one of the monitors becomes inoperative, or requires maintenance, the other monitor can be used to monitor any or all of the steam generators.

The output of the detectors is transmitted to the control room to provide indication, recording, and alarm functions. A high activity level is indicated by both audio and visual alarms.

The reference chapters are as follows:

Title	Chapter
Reactor Coolant System	4
Auxiliary and Emergency Systems	9
Radioactive Wastes and Radiation Protection	11

1.4.17 Monitoring Radioactive Releases

Means are provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program is maintained to confirm that radioactivity releases to the environs of the plant have not been excessive.

The containment atmosphere, the plant vent, and the waste disposal system liquid effluent discharge are monitored for radioactivity concentration during all normal operations, from anticipated transients, and from accident conditions.

All gaseous effluent from possible sources of accident releases of radioactivity external to the reactor containment (e.g., the spent-fuel pool and waste-handling equipment) are exhausted from monitored ventilation effluent pathways. Accident spills of liquids are maintained within the auxiliary building and collected in sumps. Any contaminated liquid effluent discharged to the condenser circulating water discharge canal is monitored. For the case of leakage from the reactor containment under accident conditions, the station radiation monitoring system, supplemented by portable survey equipment, will provide adequate monitoring of accident releases. The details of the procedures and equipment to be used in the event of an accident are specified in the station Emergency Plan Implementing Procedures (EPIPs).

The reference chapter is as follows:

Title	Chapter
Radioactive Wastes and Radiation Protection	11

1.4.18 Monitoring Fuel and Waste Storage

Monitoring and alarm instrumentation is provided for fuel and waste storage and handling areas for conditions that might contribute to a loss of continuity in decay heat removal and to radiation exposures.

The spent-fuel pool water temperature and level are continuously monitored. The temperature is displayed in the control room where an audible alarm sounds if the water temperature increases above a preset level. Audible alarms sound in the control room if the water level exceeds the high-level or low-level setpoints. The radiation level above the spent-fuel pool is continuously monitored by a radiation detector mounted on the fuel pool movable platform. A dose rate in excess of a preset level initiates an audible and visible alarm locally and in the control room. Continuous surveillance of radiation levels in the waste storage and handling areas is maintained by an appropriately mounted radiation detector. Radiation levels in excess of preset levels initiate audio and visual alarms locally and in the control room.

The reference chapters are as follows:

Title	Chapter
Auxiliary and Emergency Systems	9
Radioactive Wastes and Radiation Protection	11

1.4.19 Protection Systems Reliability

Protection systems are designed for high functional reliability and inservice testability necessary to avoid undue risk to the health and safety of the public.

The reactors use the Westinghouse magnetic-type control rod drive mechanisms that are similar to those used in the San Onofre, Indian Point, and Connecticut Yankee power stations. Upon a loss of power to the coils, the control rod assembly is released and falls by gravity into the core.

All reactor protection channels are supplied with sufficient redundancy to provide the capability for channel calibration and testing at power. The bypass removal of one trip circuit is accomplished by placing that circuit in a half-tripped mode; that is, a two-out-of-three circuit becomes a one-out-of-two circuit. Testing does not trip the system unless a trip condition exists in a concurrent channel. Reliability and independence are obtained by redundancy within each tripping function.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Instrumentation and Control	7

1.4.20 Protection Systems Redundancy and Independence

Redundancy and independence designed into the protection systems are sufficient to ensure that no single failure or removal from service of any component or channel of such a system results in a loss of the protection function. The redundancy provided includes, as a minimum, two channels of protection for each protection function to be served.

The reactor protection system is designed in accordance with the IEEE *Standards for Nuclear Power Plant Protection Systems*.

Two reactor trip breakers are provided to interrupt power to the control rod drive mechanisms. The main breaker contacts are connected in series with the mechanism coils. Opening either breaker interrupts power to all mechanisms, causing them to release all control rod assemblies to fall by gravity into the core. Each breaker is opened through an undervoltage trip coil. A shunt trip relay is installed in parallel with the undervoltage attachment. Upon de-energization, contacts from the relay energize the reactor trip breaker shunt trip attachment and trips open the breaker. This provides a redundant/backup means to automatically trip the breakers upon the receipt of a trip signal from the reactor trip system. Each protection channel permits the actuation of one reactor trip breaker undervoltage trip coil. The protection system is thus inherently safe in the event of a loss of power to the control rod drive mechanisms.

The initiation of the engineered safeguards provided for the LOCA is accomplished from redundant signals derived from reactor coolant system and containment instrumentation. Channel independence is carried throughout the system from the sensors to the output relays, including the power supplies for the channels.

The reference chapter is as follows:

Title	Chapter
Instrumentation and Control	7

1.4.21 Single Failure Definition

Multiple failures resulting from a single event are treated as a single failure.

The requirements of this criterion are included in the criterion of Section 1.4.23.

1.4.22 Separation of Protection and Control Instrumentation Systems

Protection systems shall be separated from control instrumentation systems to the extent that the failure or removal from service of any control instrumentation system component or channel, or of those components or channels common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

The coincident trip philosophy is employed to prevent a single failure from causing a spurious trip or from defeating the function of any channel.

Each reactor trip circuit is designed so that the trip occurs upon the de-energization of the circuit; an open circuit or loss of power to a channel will, therefore, cause that channel to go into its trip mode. Redundancy within each channel provides reliability and independence of operation. Channel independence is carried throughout the system from the sensor to the relay providing the logic. In some cases, however, it is desirable to employ a common sensor for both a control and a protection channel. Both functions are fully isolated in the remainder of the channel, control being derived from the primary safety signal path through an isolation amplifier. Thus, a failure in the control circuitry does not adversely affect the safety channel.

The reference chapter is as follows:

Title	Chapter
Instrumentation and Control	7

1.4.23 Protection Against Multiple Disability for Protection Systems

The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal or accident conditions, do not result in the loss of protection function or will be tolerable on some other basis.

The components of the reactor protection system are designed and arranged so that their environment in any emergency situation in which the components are required to function does not interfere with that function.

Each of the engineered safety features is designed to tolerate a single failure during the period of recovery following an incident, without loss of its protective function. This period of recovery consists of two segments, the short-term period and the long-term period. During the short-term period, the single failure is limited to a failure of an active component to complete its function as required. Should the single failure occur during the long-term rather than the short-term period, the safety-related system is designed to tolerate an active failure or a passive failure without loss of its protective function.

The following definitions pertain to the protection against multiple disability criteria:

Period of recovery - The time necessary to bring the plant to a cold shutdown and regain access to faulted equipment. The recovery period is the sum of the short- and long-term periods defined below.

Short term - The time from the initiation of the accident until the plant enters the recirculation phase of accident mitigation.

Long term - The time from when the plant enters the recirculation phase of the accident mitigation until the plant enters a cold shutdown mode and has the capability to access faulty equipment.

Active failure - The failure of a powered component, such as a piece of mechanical equipment, component of the electrical supply system, or instrumentation and control equipment, to act on command to perform its design function. Examples include the failure of a motor-operated valve to move to its correct position; the failure of an electrical breaker or relay to respond; the failure of a pump, fan, or diesel generator to start; etc.

Passive failure - The structural failure of a static component, which limits the component's effectiveness in carrying out its intended function. Examples include the failure of a battery or a cable.

Equipment moving spuriously from the proper safeguards position without signal, such as a motor-operated valve inadvertently shutting at the moment it is required, is not considered as an active failure.

The reference chapter is as follows:

Title	Chapter
Instrumentation and Control	7

1.4.24 Emergency Power for Protection Systems

In the event of loss of all offsite power, sufficient alternative sources of power are provided to permit the required functioning of the protection systems.

There are four separate 120V ac vital buses, each supplied by an independent 15 kVA inverter power supply. The inverter is housed within an electrical cabinet, which also contains a rectifier/charger, a static transfer switch, a manual bypass switch, and a voltage regulating line conditioner (RLC). This configuration is shown in Reference Drawing 1. The inverters are supplied in pairs by a common station battery. Each inverter pair and one battery form a safety train of uninterruptable power. There are two station batteries and inverter pairs per nuclear unit at Surry, which provide two independent redundant uninterruptable power supply (UPS) electrical trains. Normally, the inverter load is absorbed by the UPS rectifier/charger. The emergency onsite power required to operate safety related protection systems equipment is supplied by three 100%-capacity diesel generators for the two units.

The reference chapter is as follows:

Title	Chapter
Electrical Systems	8

1.4.25 Demonstration of Functional Operability of Protection Systems

Means shall be included for the suitable testing of the active components of protection systems while the reactor is in operation to determine if a failure or loss of redundancy has occurred.

Each protection channel in service at power is capable of being calibrated and tripped independently by simulated signals for test purposes to verify its operation. This includes a check through to the trip breakers that includes the trip logic. Thus, the operability of each trip channel is determined conveniently and without ambiguity.

The reference chapter is as follows:

Title	Chapter
Instrumentation and Control	7

1.4.26 Protection Systems Fail-Safe Design

The protection systems are designed to fail into the safe state or into a state established as tolerable on a defined basis if conditions such as a disconnection of the system, a loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

Each reactor trip circuit is designed so that trip occurs when the circuit is de-energized. An open circuit or loss of channel power therefore causes the system to go into its trip mode. In a two-out-of-three circuit, the three channels are equipped with separate primary sensors and each channel is energized from two independent electrical buses. Failure to de-energize when required is a mode of malfunction that affects only one channel. The trip signal furnished by the two remaining channels is unimpaired in this event.

The signal for containment isolation, except as initiated by safety injection, is developed from a three-out-of-four circuit in which each channel is separate and independent. The circuit signals for containment isolation upon high or high-high containment pressure. The failure of any one channel to energize when required does not interfere with the proper functioning of the isolation circuit. Each channel has provision for periodic tests to prove the ability to operate when energized.

Reactor trip is implemented by interrupting power to the magnetic latch mechanisms on each drive, allowing the control rod assemblies to insert by gravity. The protection system is thus inherently safe in the event of a loss of power.

The reference chapter is as follows:

Title	Chapter
Instrumentation and Control	7

1.4.27 Redundancy of Reactivity Control

Two independent control systems, preferably of different principles, are provided.

One of the two reactivity control systems employs control rod assemblies to regulate the position of neutron absorber within the reactor core. The other reactivity control system employs the chemical and volume control system to regulate the concentration of boron neutron absorber in the reactor coolant system.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Instrumentation and Control	7
Auxiliary and Emergency Systems	9

1.4.28 Reactivity Hot Shutdown Capability

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition.

The reactivity control systems are capable of making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes. The maximum excess reactivity expected for reload cores occurs at the beginning of life, no xenon conditions.

The control rod assemblies are divided into two categories, control groups and shutdown groups. The control groups, used in combination with soluble boron control, provide control of the reactivity changes of the core throughout the life of the core at power conditions. The control groups are used to compensate for short-term reactivity changes at power that might be produced by variations in reactor power requirements or in coolant temperature. The soluble boron control is used to compensate for the more slowly occurring changes in reactivity throughout core life as well as those attributable to fuel depletion and fission product buildup.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Auxiliary and Emergency Systems	9

1.4.29 Reactivity Shutdown Capability

One of the reactivity control systems provided is capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. The shutdown margin should ensure subcriticality with the most reactive control rod fully withdrawn.

The reactor core, together with the reactor control and protection system, is designed so that the minimum DNB ratio is at least the design DNBR limit (Section 3.2.3) and there is no fuel melting during normal operation, including periods of anticipated transients.

The shutdown groups of control rod assemblies are provided to supplement the control groups to make the reactor at least 1.77% delta k/k subcritical, following trip from any credible operating condition to the hot, zero-power condition, assuming the most reactive control rod assembly remains in the fully withdrawn position. Sufficient shutdown capability is also provided to ensure no DNB occurs for the most severe anticipated cooldown transient associated with a single active failure (i.e., the accidental opening of a steam bypass or relief valve). Thus, shutdown capability is achieved by a combination of control rod assemblies and automatic boron addition via the safety injection system with the most reactive control rod assembly assumed to be fully withdrawn. Manually controlled boron addition is used to supplement the control rod assemblies in maintaining the shutdown margin for the long-term conditions of xenon decay and unit cooldown.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Engineered Safeguards	6
Auxiliary and Emergency Systems	9

1.4.30 Reactivity Holddown Capability

The reactivity control systems provided are capable of (1) making the core subcritical under credible accident conditions, with appropriate margins for contingencies, and (2) limiting any subsequent return to power such that there is no undue risk to the health and safety of the public.

The reactivity control systems provided are capable of making and holding the core subcritical under accident conditions in a timely fashion, with appropriate margins for contingencies. Normal reactivity shutdown capability by control rod assemblies is provided within 2.4 seconds after a trip signal and this is followed by boron injection to compensate for the long-term xenon decay transient and for unit cooldown. Any time that the reactor is at power, the quantity of boric acid retained in the boric acid tanks and ready for injection exceeds that quantity required for the normal cold shutdown. This quantity always exceeds the quantity of boron required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Auxiliary and Emergency Systems	9

1.4.31 Reactivity Control System Malfunction

The reactor protection systems are capable of protecting against any single malfunction of the reactivity control system, such as the unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with control rod assemblies is completely independent of the normal control functions, since the trip breakers completely interrupt the power to the control rod drive mechanisms regardless of existing control signals. The protection systems limit reactivity transients so that the DNBR is not less than the design DNBR limit (Section 3.2.3) for any single malfunction in the reactor control system or in the de-boration controls.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Instrumentation and Control	7
Auxiliary and Emergency Systems	9

1.4.32 Maximum Reactivity Worth of Control Rods

Limits, which include reasonable margin, are placed on the maximum reactivity worth of control rods or elements and on the rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (1) rupture the reactor coolant pressure boundary, or (2) disrupt the core, its support structures, or other vessel internals sufficiently to lose the capability of cooling the core.

Limits, which include considerable margin, are placed on the maximum reactivity worth of control rod assemblies or elements and on the rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (1) rupture the reactor coolant pressure boundary or (2) disrupt the core, its support structures, or other vessel internals so as to lose the capability to cool the core.

The wiring arrangement for the control rod drive mechanisms prevents the withdrawal of control rod assemblies except as part of a select group of which each is part.

The maximum reactivity insertion rate is analyzed in a detailed unit analysis that assumes the two highest-worth sequential groups to be accidentally withdrawn at maximum speed, yielding reactivity insertion rates that are well within the capability of the overpower-overtemperature protection circuits to prevent core damage.

No credible mechanical or electrical control system malfunction can cause a control rod assembly to be withdrawn at a speed greater than its mechanical limit.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Instrumentation and Control	7
Safety Analysis	14

1.4.33 Reactor Coolant Pressure Boundary Capability

The reactor coolant pressure boundary is capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release is taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod drop, or cold water addition.

The reactor coolant pressure boundary is capable of accommodating without rupture the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a control rod assembly ejection.

The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod assemblies are used to control load variations only and core depletion is followed with boron dilution, only the control rod assemblies in the controlling group are inserted in the core at power, and these assemblies are only partially inserted. A control rod assembly insertion limit monitor is provided as an administrative aid to the operator to ensure that this condition is met.

Through the arrangement of fuel assemblies, the design limits the maximum fuel temperature for the highest-worth ejected rod. This maximum temperature value precludes any resultant damage to the primary system pressure boundary such as gross fuel dispersion in the coolant and possible excessive pressure surges.

The failure of a rod mechanism housing causing a control rod to be rapidly ejected from the core is evaluated as a theoretical, though not a credible, accident. While limited fuel damage could result from this hypothetical event, the fission products are confined to the reactor coolant system and the reactor containment. The environmental consequences of rod ejection are less severe than those of the hypothetical loss of coolant, from which public health and safety are shown to be adequately protected.

The reference chapters are as follows:

Title	Chapter
Reactor	3
Reactor Coolant System	4
Safety Analysis	14

1.4.34 Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention

The reactor coolant pressure boundary is designed and operated to reduce to an acceptable level the probability of a rapidly propagating failure. Consideration is given to (1) the provisions for control over service temperature and irradiation effects that may require operational restrictions, (2) the design and construction of the reactor pressure vessel in accordance with applicable codes, including those that establish the requirements for the absorption of energy within the elastic strain energy range and for the absorption of energy by plastic deformation, and (3) the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.

The reactor coolant pressure boundary is designed to reduce the probability of a rapidly propagating failure to an acceptable level.

The fast neutron exposure of the core region of the reactor vessel changes the notch toughness of the vessel material. This change is indicated by the increase in the nil ductility transition temperature and allowance for it is made in the operating procedures by ensuring that the vessel is not subjected to full operating pressure until its temperature exceeds the design transition temperature, defined to be the nil ductility transition temperature plus a 60°F margin. The pressure during unit start-up and shutdown at temperatures below the nil ductility transition temperature are maintained below the threshold of concern for safe operation.

The design transition temperature dictates the procedures to be followed in hydrostatic testing and in station operations to avoid excessive cold stress. The value of the design transition temperature is increased during the life of the station as required by the expected shift in the nil ductility transition temperature, which is confirmed by the experimental data obtained from irradiated specimens of reactor vessel materials during the unit lifetime.

All pressure-containing components of the reactor coolant system are designed, fabricated, inspected, and tested in conformance with the applicable codes.

The reference chapter is as follows:

Title	Chapter
Reactor Coolant System	4

1.4.35 Reactor Coolant Pressure Boundary Brittle Fracture Prevention

For conditions under which reactor coolant pressure boundary system components constructed of ferritic materials may be subjected to potential loadings, such as a reactivity-induced loading, service temperatures shall be at least 120°F above the nil ductility transition temperature of the component material if the resulting energy release is expected to be absorbed by plastic deformation, or 60°F above the nil ductility temperature of the component material if the resulting energy release is expected to be absorbed within the elastic strain energy range.

Sufficient testing and analysis of materials used in reactor coolant system components are performed to ensure that the required nil ductility transition temperature limits specified in the criterion are met. Removable test capsules are installed in the reactor vessel and removed and tested at various times in the unit lifetime to determine the effects of the operation on system materials.

The reference chapter is as follows:

Title	Chapter
Reactor Coolant System	4

1.4.36 Reactor Coolant Pressure Boundary Surveillance

Reactor coolant pressure boundary components have provisions for the inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming to current applicable codes is provided.

The design of the reactor vessel and its arrangement in the system permit accessibility during service life to all internal surfaces of the vessel and to certain external zones such as the areas of the nozzle-to-piping welds and the top and bottom heads. The reactor arrangement within the containment provides sufficient space for the inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete.

The monitoring of the nil ductility transition temperature properties of the core region plates, forgings, weldments, and associated heat-treated zones is performed in accordance with ASTM E 185, *Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors*. Samples of reactor vessel plate materials are retained and cataloged in case future engineering development shows the need for further testing.

The material properties surveillance program includes not only the conventional tensile tests, but also tests of fracture mechanics specimens. The fracture mechanics specimens are the wedge-opening-loading-type specimens. The observed irradiation shifts in the nil ductility transition temperature of the core region materials are used to confirm the calculated limits to start-up and shutdown transients.

To define permissible operating conditions below the design transition temperature, a pressure range is established. The range is bounded by a lower limit for pump operation and an upper limit that satisfies reactor vessel stress criteria. To allow for thermal stresses during the heat-up or cooldown of the reactor vessel, an equivalent pressure limit is defined to compensate for thermal stress as a function of the rate of change of coolant temperature. Since the normal operating temperature of the reactor vessel is well above the maximum expected design transition temperature, brittle fracture during normal operation is not considered to be a credible mode of failure.

The reference chapter is as follows:

Title	Chapter
Reactor Coolant System	4

1.4.37 Engineered Safeguards Basis for Design

Engineered safeguards are provided in the facility to back up the safety provided by the design of the core, the reactor coolant pressure boundary, and their protection systems. Such engineered safeguards are designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary and an unobstructed discharge from both ends.

Engineered safeguards are provided to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe in that boundary and an unobstructed discharge from both ends, and to separately cope with any steam or feedwater line break.

Limiting the release of fission products from the reactor fuel is accomplished by the safety injection system, which, by cooling the core, keeps the fuel in place and substantially intact and significantly limits the metal-water reaction.

A reinforced-concrete, steel-lined containment structure (Section 1.4.10), operating at subatmospheric pressure, is provided to enclose the entire reactor coolant system. It is designed to sustain, without loss of required integrity, all effects of gross equipment failures up to and including the rupture of the largest pipe in the reactor coolant system.

The reference chapter is as follows:

Title	Chapter
Engineered Safeguards	6

1.4.38 Reliability and Testability of Engineered Safeguards

All engineered safeguards are designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public.

A comprehensive program of testing has been formulated for all equipment, systems, and system controls vital to the functioning of engineered safeguards. The program consists of performance tests of individual pieces of equipment in the manufacturer's shop, integrated tests of the system as a whole, and periodic tests of the activation circuitry and mechanical components to ensure reliable performance, upon demand, throughout the unit lifetime.

The engineered safeguards components are checked periodically and routinely. In the event that one of the components requires maintenance as a result of failure to perform according to prescribed limits during the test, the necessary corrections or minor maintenance are accomplished and the component is retested immediately.

The reference chapter is as follows:

Title	Chapter
Engineered Safeguards	6

1.4.39 Emergency Power for Engineered Safeguards

Alternative power systems are provided and designed with adequate independence, redundancy, capacity, and testability to permit the functioning required of the engineered safeguards. As a minimum, the onsite power system and the offsite power system each, independently, provide this capacity, assuming the failure of a single active component in each power system.

Two independent sections of emergency 4160V buses and switchgear are provided for each unit. Each section is sized to carry 100% of the emergency load and may be energized by either onsite or offsite power supplies. The onsite and offsite power supplies are both independently capable of supplying power to the engineered safeguards. This capability is maintained even in the event of a failure of any single active component in either system. In the unlikely event of total loss of offsite power, the emergency 4160V buses are energized by the emergency diesel generators. Three diesel generators are available for two units. One diesel is exclusively for Unit 1, the second is exclusively for Unit 2, and the third functions as a backup for either unit. Each diesel generator is connected to one of the emergency buses, and each bus is connected to one set of the duplicated engineered safeguards equipment, thus ensuring operations of safeguards equipment under all conditions, including the failure of a single component in each power system. Sections 8.4.1 and 8.5 discuss the alternate station power systems and emergency power system, respectively.

Tests of the automatic operation of the power source transfer system at the 4160V level are made during shutdown for refueling to ensure that station on-site power is supplied automatically when an offsite power source is out of service. The periodic starting and loading of each emergency diesel generator and its emergency bus ensures the operability of the emergency power supply in the event of loss of off-site power.

The reference chapter is as follows:

Title	Chapter
Electrical Systems	8

1.4.40 Missile Protection

Protection for engineered safeguards is provided against dynamic effects and missiles that might result from plant equipment failures.

Layout and structural design specifically protects the injection lines leading to unbroken reactor coolant loops against damage as a result of the maximum reactor coolant system pipe rupture. The separation of individual injection lines is provided to the maximum extent practicable. The movement of injection lines associated with the rupture of a reactor coolant loop is accommodated by line flexibility and by the design of the pipe supports, so that no damage beyond the missile barrier is credible.

The reference chapters are as follows:

Title	Chapter
Reactor Coolant System	4
Containment System	5
Engineered Safeguards	6

1.4.41 Engineered Safeguards Performance Capability

Engineered safeguards, such as the safety injection system and the containment heat removal system, provide sufficient performance capability to accommodate the failure of any single active component without any undue risk to the health and safety of the public.

The overall capability of the engineered safeguards meets the suggested requirements of 10 CFR 50.67 or RG 1.183, as applicable, for the occurrence of any rupture of a reactor coolant or main steam system pipe, including the double-ended rupture of a reactor coolant pipe, known as the design-basis accident.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6
Safety Analysis	14

1.4.42 Engineered Safeguards Components Capability

Engineered safeguards are designed so that the capability of these features to perform their required function is not impaired by the effects of a LOCA to the extent of causing undue risk to the health and safety of the public.

Instrumentation, motors, cables, and penetrations inside the containment are selected to meet the most adverse accident conditions to which they may be subjected. These items are either protected from containment accident conditions or are designed to withstand, without failure, exposure to the worst combination of temperature, pressure, and humidity expected during the required operational period.

The safety injection system piping serving each loop is anchored at the missile barrier in each loop area to restrict potential accident damage to the portion of piping beyond this point. The anchorage is designed to withstand, without failure, the thrust force of any branch line served from the reactor coolant pipe and discharging fluid to the atmosphere, and to withstand a bending moment equivalent to that which produces failure of the piping under the action of free and unrestrained discharge to atmosphere or the motion of the broken reactor coolant pipe to which the safety injection system pipes are connected. This prevents possible failure at any point upstream from the support point, including the branch line connection into the piping header.

The containment spray and recirculation spray piping has been installed with sufficient anchors, constraints, and guides to withstand the effects of operating-basis and design-basis earthquakes. This piping has also been installed to withstand the effects of dead weight, thermal, and pressure forces in the piping. Redundant containment spray and recirculation spray piping systems have been installed to preclude the possibility of sprays being lost as a result of pipe failure.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6

1.4.43 Accident Aggravation Prevention

Protection against any action of the engineered safeguards that accentuates significantly the adverse after effects of a loss of normal cooling is provided.

The reactor is maintained subcritical following a pipe rupture accident. The introduction of borated cooling water into the core does not result in a net positive reactivity addition. The control rod assemblies insert and remain inserted.

The supply of water by the safety injection system to cool hot core cladding does not produce significant metal-water reactions.

The delivery of cold emergency core cooling water to the reactor vessel following accidental expulsion of reactor coolant does not cause a further loss of integrity of the reactor coolant system boundary.

The reference chapter is as follows:

Title	Chapter
Engineered Safeguards	6

1.4.44 Safety Injection System Capability

A safety injection system with the capability for accomplishing adequate emergency core cooling is provided. This core cooling system and the core are designed to prevent fuel and clad damage that interferes with the emergency core cooling function and to keep the clad metal-water reaction within acceptable limits for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such a safety injection system is evaluated conservatively in each area of uncertainty.

The safety injection system employs a passive system of accumulators that do not require any external signals or source of power for their operation to cope with the short-term cooling requirements of a large reactor coolant pipe break. The high-head and the low-head safety injection systems, each capable of supplying the required emergency cooling, are also provided for small-break protection and to keep the core submerged after the accumulators have discharged following a large break. These systems are arranged so that the single failure of any active component does not interfere with meeting the short-term cooling requirements.

The high-head and low-head safety injection systems are each capable of fulfilling long-term cooling requirements. The failure of any single active component or the development of excessive leakage during the long-term cooling period does not interfere with the ability to meet necessary long-term cooling objectives with one of the systems.

The primary purpose of the safety injection system is to automatically deliver cooling water to the reactor core in the event of a LOCA. This limits the fuel clad temperature and thereby ensures that the core remains intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

1. All pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant loop, assuming unobstructed discharge from both ends.
2. A loss of coolant associated with the rod ejection accident.
3. A steam generator tube rupture.

The basic design criteria for LOCA evaluations are:

1. The cladding temperature is less than
   a. The melting temperature of zirconium alloy cladding material.
   b. The temperature at which gross core geometry distortion, including clad fragmentation, may be expected.
2. The total core metal-water reaction is limited to less than 1%.

Meeting these criteria ensures that the core geometry remains in place and substantially intact to such an extent that effective cooling of the core is not impaired.

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the safety injection system adds shutdown reactivity so that with an assumed stuck control rod assembly, no offsite power, and minimum engineered safeguards, there is no consequential damage to the primary system, and the core remains in place and intact. When there is no stuck control rod assembly, offsite power is available, and all equipment is operating at design capacity, there is no significant cladding rupture.

The reference chapters are as follows:

Title	Chapter
Engineered Safeguards	6
Safety Analysis	14

1.4.45 Inspection of Safety Injection System

Design provisions, where practical, are made to facilitate the physical inspection of all critical parts of the safety injection system, including reactor vessel internals and water injection nozzles.

Design provisions are made for the inspection of all components of the safety injection system to the extent practical. An inspection is performed periodically to demonstrate system readiness.

The pressure containment boundaries can be inspected for leaks from pump seals, valve packing, flanged joints, and safety valves during system testing.

In addition, critical parts of the reactor vessel internals, injection nozzles, pipes, valves, and safety injection pumps can be inspected visually or by boroscopic examination for evidence of erosion, corrosion, and vibration wear, and non-destructive tests can be performed where such techniques desirable, practical, and appropriate.

The reference chapter is as follow:

Title	Chapter
Engineered Safeguards	6

1.4.46 Testing of Safety Injection System Components

Design provisions are made so that components of the safety injection system can be tested periodically for operability and functional performance.

The design provides for the periodic testing of active components of the safety injection system for operability and functional performance.

Preoperational performance tests of the components were performed in the manufacturer's shop. An initial system flow test, performed prior to initial criticality, demonstrated the proper functioning of the system. Thereafter, periodic tests demonstrate that components are functioning properly.

Each active component of the safety injection system may be individually actuated on the normal power source at any time during station operation to demonstrate operability. The test of the safety injection pumps, which perform as charging pumps during normal operation, employs a minimum-flow recirculation test line that connects back to the volume control tank. Remotely operated valves are exercised and actuation circuits tested. The automatic actuation circuitry, valves, and pump breakers also may be checked during integrated system test periods.

The reference chapters are as follows:

Title	Chapter
Engineered Safeguards	6
Instrumentation and Control	7

1.4.47 Testing of Safety Injection System

Capability is provided to test periodically the operability of the safety injection system up to a location as close to the core as is practical.

Design provisions include special instrumentation, testing, and sampling lines to perform the tests, and unit shutdown to demonstrate the proper automatic operation of the safety injection system. A test signal is supplied to initiate automatic action. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry. In addition, other tests are performed periodically to verify that the safety injection pumps attain required discharge heads.

The accumulator tank pressure and level are continuously monitored during unit operation, and flow from the tanks can be checked at any time using test lines.

The reference chapters are as follows:

Title	Chapter
Engineered Safeguards	6
Instrumentation and Control	7

1.4.48 Testing of Operational Sequence of Safety Injection System

Capability shall be provided to test, under conditions as close as practical to design, the full operational sequence that would bring the safety injection system into action, including the transfer to alternative power sources.

The design provides for the capability to test initially, to the extent practical, the full operational sequence up to the design conditions for the safety injection system to demonstrate the state of readiness and capability of the system. This functional test is performed with the reactor coolant system initially cold and at low pressure. The safety injection system valving is set to initially simulate the system alignment for power operation. This test may be conducted on the normal shutdown power system, and it may include transfer to the alternative power source.

During the initial system checkout, the functioning of the accumulators is checked by closing the stop valve, raising the pressure in the tank, and then opening the stop valve and observing the rising pressurizer level. The rising water level in the pressurizer provides an indication of system delivery.

The reference chapter is as follows:

Title	Chapter
Engineered Safeguards	6

1.4.49 Containment Design Basis

The containment structure, including access openings and penetrations and any necessary containment heat removal systems, is designed to accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for the effects of metal-water or other chemical reactions that can occur as a consequence of the failure of safety injection systems.

The design of the containment structure is based on the design basis accident, discussed in Sections 5.4.1 and 5.4.2 which assumes a double-ended rupture of the largest pipe in the reactor coolant system, coupled with partial loss of the redundant engineered safeguards systems (minimum safeguards). The maximum containment pressure reached in a design basis accident is less than the 45-psig design limit. Further, the containment analyses performed assume a 2% metal-water reaction which is well above the less than 1% expected for all accidents considered.

The containment structure, including access openings and penetrations, is designed to withstand a pressure of 45 psig and the associated thermal effects without exceeding the design leakage rate of 0.1 weight percent of containment air per 24 hours.

The heat removal capacity of the containment spray systems for the minimum safeguards returns the containment pressure to a subatmospheric condition in less than 60 minutes after a design-basis accident. This original design criterion was modified in conjunction with the analyses for implementation of the alternative source term. The criteria were subsequently updated to support an increase in the containment depressurization profile for the alternative source term analyses. The updated criteria require that, following the LOCA, the containment pressure be less than 2.0 psig within 1 hour and less than 0.0 psig within 6 hours. The radiological consequences analysis demonstrates acceptable results provided the containment pressure does not exceed 2.0 psig for the interval from 1 to 6 hours following the Design Basis Accident. Beyond 6 hours, containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6
Safety Analysis	14

1.4.50 Nil Ductility Transition Temperature Requirement for Containment Material

Principal load-carrying components of ferritic materials exposed to the external environment are selected so that their temperatures under normal operating and testing conditions are not less than 30°F above nil ductility transition (NDT) temperature.

The containment liner is not exposed to the external environment. However, the containment liner has sufficient ductility to tolerate local deformations without rupture. The liner material has a nil ductility transition temperature of -20°F, which is 80°F below the normal minimum shutdown temperature of 60°F. The equipment and personnel hatches are made of steel with a nil ductility transition temperature of -20°F. Exposed hatch surfaces during station operation are not expected to be at a temperature below 10°F.

The reference chapter is as follows:

Title	Chapter
Containment System	5

1.4.51 Reactor Coolant Pressure Boundary Outside Containment

If part of the reactor coolant pressure boundary is outside the containment, appropriate features, as necessary, are provided to protect the health and safety of the public in case of an accidental rupture in that part. The determination of the appropriateness of features, such as isolation valves and additional containment, includes a consideration of the environmental and population conditions surrounding the site.

No portions of the reactor coolant pressure boundary extend beyond the containment barrier.

1.4.52 Containment Heat Removal Systems

Where active heat removal systems are needed under accident conditions to prevent exceeding containment design pressure, at least two systems, preferably of different principles, each with full capacity, are provided.

Four separate containment recirculation spray subsystems, each with approximately 50% capacity, serve to remove heat from the containment after a LOCA, as described in Section 6.3.1. Each subsystem contains one deepwell-type pump. In two subsystems, the recirculation spray pumps are located inside the containment. In the other two subsystems, the recirculation spray pumps are located in the containment auxiliary structures and are accessible for servicing at all times.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6

1.4.53 Containment Isolation Valves

Penetrations that require closure for the containment function are protected by redundant valving and associated apparatuses.

All penetrations requiring valve closure for containment isolation have redundant valving so that the failure of one valve does not prevent the isolation of the containment. No manual operation or action is required to activate the valves to effect isolation. All remotely actuated valves have their positions indicated in the control room at group visual position indicators.

The reference chapter is as follows:

Title	Chapter
Containment System	5

1.4.54 Initial Containment Leakage Rate Testing

The containment is designed so that integrated leakage rate testing can be conducted at design pressure after the completion and installation of all penetrations, and the leakage rate can be measured over a sufficient period of time to verify its conformance with required performance.

Refer to the response to the criterion in Section 1.4.55.

1.4.55 Periodic Containment Leakage Rate Testing

The containment is designed so that integrated leakage rate testing can be done periodically at design pressure during the plant lifetime.

The test frequency, test pressure, and type of test used are in accordance with Technical Specifications.

The completed containment structure, with all necessary penetrations, is designed so that leakage does not exceed 0.1% of the contained volume per day at the design pressure of 45 psig. Upon completion of the construction of the containment structure and the installation of all penetrations, Type A tests of the containments were performed at 39.2 psig and 25 psig. The tests were performed using the leakage monitoring system described in Section 5.3.2. Since the normal operating pressure of the containment is subatmospheric, containment leakage is monitored continuously by means of the leakage monitoring system.

The periodic leakage rate retest is conducted at a single test pressure. During the interval between the periodic leakage rate retests, a series of periodic surveillance tests (Type B and C tests) are carried out to monitor the principal sources of leak development.

The reference chapter is as follows:

Title	Chapter
Containment System	5

1.4.56 Provision for Testing of Penetrations

Provisions are made for testing penetrations that have resilient seals or expansion bellows to permit leaktightness to be demonstrated at design pressure at any time.

All penetrations having resilient seals or expansion bellows are fitted with test connections to permit pressurization to 50 psig to demonstrate leaktightness.

The reference chapter is as follows:

Title	Chapter
Containment System	5

1.4.57 Provision for Testing of Isolation Valves

The capability is provided for testing the functional operability of valves and associated apparatuses essential to the containment function, for establishing that no failure has occurred, and for determining that valve leakage does not exceed acceptable limits.

Type C tests are performed on the isolation valves to verify their sealing capability and leaktightness as described in Section 5.5. The tests include valve closure and leakage tests. Isolation valves, which are normally closed, are exercised to verify closure and sealing capabilities. Valve leakage tests are performed in accordance with the requirements of the Type C test.

The reference chapter is as follows:

Title	Chapter
Containment System	5

1.4.58 Inspection of Containment Pressure-Reducing Systems

Design provisions are made to facilitate the periodic physical inspection of all important components of the containment pressure-reducing systems such as pumps, valves, spray nozzles, torus, and sumps.

Equipment composing the engineered safeguards systems is so situated that periodic physical inspections can be made. All equipment can be inspected during planned refueling shutdowns.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6

1.4.59 Testing of Containment Pressure-Reducing Systems Components

The containment pressure-reducing systems are designed so that active components such as pumps and valves can be tested periodically for operability and required functional performance.

The containment recirculation spray pumps and valves are tested, periodically, by manually closing the required breakers in the control room to test actuation and component operation. Bypass lines on the recirculation spray pumps located outside the containment permit flow measurements to be made, which can then be compared to the results of preoperational tests. The recirculation spray pumps located inside the containment are periodically tested to ensure their operability.

Bypass lines to the refueling water storage tank permit brief operational tests of the containment spray pumps. Periodic tests of the CS pump discharge MOVs demonstrate that they are functioning properly. Test air connections on the containment spray discharge lines, installed prior to the nozzle air tests, ensure that these lines and the check valves are open.

The reference chapter is as follows:

Title	Chapter
Engineered Safeguards	6

1.4.60 Testing of Containment Spray Systems

A capability is provided to test periodically the delivery capability of the containment spray systems at a position as close to the spray nozzles as is practical.

Provision is made to permit the testing of the containment spray system and the containment recirculation spray system throughout the life of the unit to ensure that the systems are operational. For preoperational testing, the ends of the spray headers are fitted with blind flanges that allow the connection of temporary drain lines for full-flow testing up to the nozzles. Such testing allows for the testing of the spray systems over the full range of flow and starting conditions.

The reference chapter is as follows:

Title	Chapter
Engineered Safeguards	6

1.4.61 Testing of Operational Sequence of Containment Pressure-Reducing Systems

A capability is provided to test, under conditions as close to design considerations as practical, the full operational sequence that brings the containment pressure-reducing systems into action, including the transfer to alternative power sources.

The design of the control system for the containment spray system and the containment recirculation spray system includes manual test switches that provide for the individual testing of all the equipment in the systems and the testing of the operational sequence of the spray systems. These tests may be conducted on the normal shutdown power system or an alternative power source.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Engineered Safeguards	6
Instrumentation and Control	7

1.4.62 Inspection of Air Cleanup Systems

Design provisions are made to facilitate the physical inspection of all critical parts of containment air cleanup systems, such as ducts, filters, fans, and dampers.

Refer to the response to the criterion in Section 1.4.65.

1.4.63 Testing of Air Cleanup Systems Components

Design provisions are made so that active components of the air cleanup systems, such as fans and dampers, can be tested periodically for operability and required functional performance.

Refer to the response to the criterion in Section 1.4.65.

1.4.64 Testing of Air Cleanup Systems

A capability is provided for the in situ periodic testing and surveillance of the air cleanup systems to ensure that (1) filter bypass paths have not developed and (2) filter and trapping materials have not deteriorated beyond acceptable limits.

Refer to the response to the criterion in Section 1.4.65.

1.4.65 Testing of Operational Sequence of Air Cleanup Systems

A capability is provided to test, under conditions as close to design conditions as practical, the full operational sequence that brings the air cleanup systems into action, including the transfer to alternative power sources and the design air flow delivery capability.

Engineered safeguards for the Surry Power Station do not include a postaccident air cleanup system. The containment ventilation system is normally in continuous service and is equipped to handle activity associated with normal station operation. No special tests or inspections of this system are performed.

1.4.66 Prevention of Fuel Storage Criticality

Criticality in the new-fuel and spent-fuel storage areas is prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls.

During reactor vessel head removal and while loading and unloading fuel from the reactor, the boron concentration of the reactor coolant system and the fuel transfer canal, reactor cavity, and spent-fuel pool is maintained at not less than that required to shut down the core to a $k_{eff} = 0.95$ with all control rods inserted. This concentration is sufficient to ensure that $k_{eff} < 1.00$ even if all control rods are withdrawn.

The new-fuel storage racks are designed so that it is impossible to insert assemblies in violation of the design in other than the lattice spacing. The fuel is stored vertically in an array with sufficient center-to-center distance between assemblies to ensure an ever-safe geometry.

The spent-fuel storage racks are designed so that it is impossible to insert assemblies in violation of the design in other than the lattice spacing. Borated water is used to fill the spent-fuel pool at a concentration to match that used in the reactor cavity during refueling operations. The fuel is stored vertically in an array with sufficient center-to-center distance between assemblies to ensure $k_{eff} \leq 0.95$, even if unborated water is used to fill the pool.

The fuel transfer equipment is designed to handle one fuel assembly at a time. The new-fuel storage area cannot be flooded.

The reference chapter is as follows:

Title	Chapter
Auxiliary and Emergency Systems	9

1.4.67 Fuel and Waste Storage Decay Heat

Reliable decay heat removal systems are designed to prevent damage to the fuel in storage facilities that can result in radioactivity release to plant-operating areas or the public environs.

Decay heat from spent fuel is dissipated in the water of the spent-fuel pool and subsequently removed by a cooling system. Redundancy of system components is provided to ensure the maintenance of storage pool water cleanliness and level, and to remove heat from the water.

The reference chapter is as follows:

Title	Chapter
Auxiliary and Emergency Systems	9

1.4.68 Fuel and Waste Storage Radiation Shielding

Shielding for radiation protection is provided in the design of fuel and waste storage facilities as required to meet the requirements of 10 CFR 20.

The spent-fuel storage pool is designed to meet 10 CFR 20 requirements in providing radiation shielding for operating personnel during fuel transfer and during storage of spent fuel. Work areas adjacent to the canal wall are shielded; however, barricades are necessary to limit personnel access during actual fuel transfers.

Waste storage and processing facilities in the auxiliary building area have shielding meeting 10 CFR 20 requirements for operating personnel.

Periodic surveys by health physics personnel using portable radiation detectors ensure that radiation design levels are not degraded during unit lifetime.

The reference chapters are as follows:

Title	Chapter
Auxiliary and Emergency Systems	9
Radioactive Wastes and Radiation Protection	11

1.4.69 Protection Against Radioactivity Release From Spent Fuel

The containment of fuel and waste storage is provided if accidents could lead to the release of undue amounts of radioactivity to the public environs.

Spent fuel systems are designed to preclude gross mechanical failures that could lead to significant radioactivity releases. In addition, during refueling, fuel building ventilation air is passed through charcoal filters, containment ventilation air is monitored, and, if airborne radioactivity increases beyond a predetermined value, the containment ventilation system is isolated automatically.

Liquid waste storage facilities are designed so that any possible release of waste liquids is contained within the facility and does not result in an uncontrolled release to the environment. Any waste liquid leakage or release from components within the auxiliary building, fuel building, decontamination building, or radwaste facility flows directly to the vent and drain system or is collected in sumps and pumped to the liquid waste disposal system. The boron recovery tanks located in the station yard area are in separately diked, Class I structures, each of which is of sufficient capacity to retain the total liquid volume resulting from the rupture of one of these tanks. Radioactive gases are stripped from the liquid stored in the boron recovery tanks so that a tank failure does not constitute a significant gaseous release.

Waste gas inventories are carefully monitored and controlled so that no single component failure would result in a whole-body dose at the site boundary greater than 25 rem. All gaseous discharges from the station are continuously monitored for particulate and gaseous radioactivity during the release.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Auxiliary and Emergency Systems	9
Radioactive Wastes and Radiation Protection	11
Safety Analysis	14

1.4.70 Control of Releases of Radioactivity to the Environment

The facility design includes those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity is provided for the retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control is justified (1) on the basis of 10 CFR 20 requirements for normal operations and for any transient situation that might reasonably be anticipated to occur and (2) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence, except that reductions of the recommended dosage levels may be required where high population densities or very large cities can be affected by the radioactive effluents.

The control of waste gas effluents is accomplished by the holdup of waste gases in buried, double-wall decay tanks until the activity of tank contents and existing environmental conditions permit discharges within 10 CFR 20 requirements. In addition, waste gas effluents are monitored at the point of discharge for radioactivity and rate of flow. No decay tank failure results in an activity release greater than 10 CFR 100 limits.

The control of liquid waste effluents is maintained by batch processing all liquids, sampling them before discharge, and controlling their rate of release, and by preventing inadvertent tank discharges. Liquid effluents are monitored for radioactivity and rate of flow. Liquid waste disposal system collection and surge tank, and the evaporator, reverse osmosis, and ion exchange capacities are sufficient to handle any expected transient in the development of liquid waste volume.

Station solid wastes are prepared batchwise for offsite disposal by approved contractors. Solid wastes are prepared for shipment by placement in shielded and reinforced containers that meet regulatory requirements.

The reference chapters are as follows:

Title	Chapter
Containment System	5
Auxiliary and Emergency Systems	9
Radioactive Wastes and Radiation Protection	11
Safety Analysis	14

1.4 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FE-1A2	One Line Integrated Schematic, Electrical Power Distribution, Units 1 & 2

Intentionally Blank

1.5 COMMON FACILITIES

Separate and similar systems and equipment are provided for each unit, except as noted below. Where some components of a system are shared by both units, only those components that are shared are listed.

1. Electrical systems (Section 8.2)

   Standby station service transformer

   Backup emergency diesel generator

2. Chemical and volume control system (Section 9.1)

   Chemical-mixing tank

   Boric acid storage tanks (three)

   Boric acid pumps (four)

   Batching tank

   Resin fill tank

3. Boron recovery system (Section 9.2)

4. Component cooling water system (Section 9.4)

   Component-cooling surge tank

   Component-cooling pumps (four)

   Component-cooling heat exchangers (four)

5. Fuel pool cooling system (Section 9.5)

   Fuel pool circulation pumps (two)

   Fuel pool skimmer pumps (two)

   Fuel pool coolers (two)

   Fuel pool skimmer filters (two)

   Fuel pool purification filter (one)

   Fuel pool ion exchanger

   Fuel pool purification pumps (two)

6. Sampling system (Section 9.6)

7. Vent and drain system (Section 9.7)

   Auxiliary building sump pumps (two)

Fuel building sump pumps (two)

Liquid waste strainers (two)

8. Service water system (Section 9.9)
9. Fire protection system (Section 9.10)
10. Ventilation system (Section 9.13) (other than containment ventilation)
11. Heating boilers (Section 10.3.2)
12. Lubricating oil system (Section 10.3.7)

    Clean and dirty lube-oil storage tanks (two)

    Transfer pump

13. Radioactive waste systems (Section 11.2)
14. Structures, buildings, and miscellaneous

    Auxiliary building

    Fuel building

    Turbine building and turbine room crane

    Service building

    Main control area

    Decontamination building

    Office building

    General station services, nonelectrical

    Fuel-oil system

    Service water pump house

    Fire-pump house

    Intake and discharge canals

    Screenwell

    Laundry facility

    Radwaste facility

1.6 RESEARCH AND DEVELOPMENT REQUIREMENTS

(Note: This is the initial plant research and development. Any post research and development is described in the individual sections.)

The design is based on proven concepts that have been developed and successfully applied to the design of PWR systems. Results of work completed under the Nuclear Safety Research and Development Program conducted by the AEC were incorporated in the design and evaluation of applicable portions of the engineered safety features.

The term “research and development” as used in this section is the same as that used by the Commission in Section 5.2 of its regulations, as follows:

(n) “Research and development” means (1) theoretical analysis, exploration or experimentation; or (2) the extension of investigative findings and theories of the scientific nature into practical application for experimental and demonstration purposes including the experimental production and testing of models, devices, equipment, materials and processes.

The research and development discussed in the FSAR is to confirm the engineering and design values normally used to complete equipment and system designs. It does not involve the creation of new concepts or ideas.

The technical information generated is used either to demonstrate the safety of the design and more sharply define margins of conservatism, or to lead to design improvements.

The schedules for development of this technical information were compatible with the plant schedule such that definite results were made available before the plant design was complete.

The Westinghouse research and development programs under way during the FSAR stages of the Surry project are listed in WCAP-7498-L, *Topical Report, Safety Related Research and Development for Westinghouse Pressurized Water Reactors*, Spring 1970 (Reference 1). This topical report is upgraded periodically.

The specific areas in which additional information was developed and which were required for unit operation are as follows:

1. Core stability evaluation.
2. Fuel rod burst program.

Other areas of research and development are those that gave added confirmation that the overall design was conservative. These programs were carried out basically to provide technical information that could be applied to component or system optimization in future plants. These programs included the following:

1. Burnable poison program.

2. Blowdown forces program.
3. Reactor vessel thermal shock analysis program.
4. Containment spray program.
5. Fuel development program.
6. Incore detector program.
7. Empire States Atomic Development Associates DNB program.
8. Full Length Emergency Core Cooling Heat Transfer Test program.
9. Flashing heat transfer program.
10. Loss of coolant analysis program.

These programs are discussed extensively in WCAP-7498-L (Reference 1).

1.6.1 Required Research and Development

There are two programs which were required for plant operation: the core stability evaluation and fuel rod burst programs.

1.6.1.1 **Core Stability Evaluation Program (Item 1 of Reference 1)**

The purpose of this program was to establish means for the detection and control of potential xenon oscillations and for the shaping of the axial power distribution for improved core performance. This program was completed in two areas:

1. Confirmation of the ability of the ex-core detector system to indicate gross core power distribution sufficient to permit xenon oscillation within specified operating limits.
2. Development of a control system using the ex-core detector system and part-length control rods. (It should be noted that the part-length rods were removed by a design change initiated in 1978.)

The third part of this program, verification through start-up testing that the control system can control the core power distribution and that adequate margins exist to operate the Surry unit, was carried out on Westinghouse reactors that were placed in operation before Surry. These included H. B. Robinson Unit 2 (Docket 50-261) and Turkey Point Unit 3 (Docket 50-250).

1.6.1.2 **Fuel Rod Burst Program (Item 2 of Reference 1)**

The basic design criteria for LOCA evaluations are given in Section 14.5.

Satisfaction of these criteria ensures that the core geometry remains in place and substantially intact to such an extent that effective cooling of the core is not impaired.

The effect of rod bursting, swelling, or shattering must be considered in the loss-of-coolant evaluations. In the blowdown phase of the accident, core geometry distortion may result from clad bursting or swelling. The clad temperature may get sufficiently high (1200° to 2000°F) that a bursting or swelling of the clad would occur by virtue of the internal gas pressure and a significant reduction of clad strength. Clad bursting or swelling is of concern because of the possibility of blocking the flow channel so that coolant flow would be insufficient to meet the above LOCA design criteria.

A program to investigate the performance of fuel rods during a simulated LOCA was completed. It supplied empirical data on the above safety-related problems from which the amount and kinds of geometry distortion can be predicted over the range of conditions of interest. The effects of this geometry distortion on the ability of the emergency core cooling system to meet the LOCA design criteria were determined using analytical design techniques.

1.6.1.2.1 Single-Rod Burst Tests (SRBT)

The performance of the fuel rods during a simulated LOCA was evaluated in a test program that is described in WCAP-7379-L, Volume I and Volume II (Reference 2).

Volume I (Westinghouse Proprietary) describes burst, quench, and eutectic formation tests with unirradiated tubes and provides an evaluation of the data from both reports. An interpretation with regard to the postulated sequence during the LOCA is given.

Volume II (Non-proprietary) reports the results of work under AEC Contract AT-(30-1)-3017 and describes burst and quench tests on irradiated tubes.

The single-rod tests indicated that rod-to-rod interference might occur following rod burst and must be considered. The quantitative evaluation of the influence of adjacent rods in a fuel assembly would be difficult, if not impossible, to determine analytically. Therefore, the rod burst program was extended to include multi-rod burst tests. Multi-rod burst tests (MRBT) were performed to demonstrate that the rods in a PWR rod bundle burst randomly so that a minimal-flow channel area, for core-cooling purposes, is maintained.

1.6.1.2.2 Multi-Rod Burst Test

The results of this phase of the rod burst program are reported in WCAP-7495-L, Volume I and Volume II (Westinghouse Proprietary) (Reference 3).

Volume I describes the test apparatus and conditions and provides an evaluation of the test results. Volume II presents the application of the MRBT results to the LOCA core thermal analysis.

The MRBT results show that the burst locations are staggered axially along the fuel rods and that, to some degree, rod-to-rod contact does occur. However, the remaining flow area is always sufficient to ensure adequate core cooling. Analytical evaluations of a typical double-ended cold-leg break, considering flow redistribution due to the geometry distortion and rod-to-rod contact, have shown that the peak clad temperature increases approximately 70°F over the 2300°F peak temperature without geometry distortion.

The program was completed and results were satisfactory. No backup research and development measures were considered necessary.

1.6.2 Other Research and Development

Other areas of research and development included those described below.

1.6.2.1 Burnable Poison Program (Item 7 of Reference 1)

Burnable poison rod development is complete. The burnable poison rods are borosilicate glass encased in stainless steel tubes. The fixed rods are used to reduce the concentration of boric acid poison in the moderator, thus ensuring that the moderator coefficient of reactivity is always negative at operating temperature.

1.6.2.2 Blowdown Forces Program (Item 15 of Reference 1)

The objective of the program was to develop digital computer programs for the calculation of pressure, velocity, and force transients in the reactor coolant system during a LOCA, and to use these codes in the calculation of blowdown forces on the fuel assemblies and reactor internals to ensure that the stress and deflection criteria used in the design of these components are met.

Westinghouse completed the development of BLODWN-2, an improved digital computer program for the calculation of local fluid pressure, flow, and density transients in the primary coolant system.

Extensive comparisons were made between BLODWN-2 and test data, and the results are given in WCAP-7401 (Reference 4). Agreement between code predictions and data was good.

An analysis using the BLODWN-2 program was completed for the Indian Point Unit 2 reactor. It was concluded from the analysis that the design of this reactor met the established design criteria. Designs for subsequent Westinghouse pressurized water reactors included the use of the BLODWN-2 program.

1.6.2.3 Reactor Vessel Thermal Shock (Item 16 of Reference 1)

The effects of safety injection water on the integrity of the reactor vessel following a postulated LOCA were analyzed using data on the fracture toughness of heavy section steel, both at beginning of plant life and after irradiation, corresponding to approximately 40 years of equivalent plant life. The results showed that, under the postulated accident conditions, the integrity of the reactor vessel is maintained.

Fracture toughness data were obtained from a Westinghouse experimental program associated with the heavy section steel technology (HSST) program at the Oak Ridge National Laboratory and with the Euratom programs. Since results of the analyses were dependent on the fracture toughness of irradiated steel, efforts continued to obtain additional fracture toughness data. The HSST program was scheduled for completion by 1973.

A detailed analysis (Reference 5) of the linear elastic fracture mechanism method, along with various sensitivity studies, was submitted to the AEC staff and members of the Advisory Committee on Reactor Safety.

Revised material for this report, plus additional analytical and fracture toughness data, was presented at a meeting with the Containment and Component Technology Branch on August 9, 1968, and forwarded by letter for AEC review and comment on October 29, 1968.

It was not anticipated that the HSST program would lead to any new conclusions about the Surry reactor vessel integrity under LOCA conditions.

Several backup positions are available if vessel integrity cannot be ensured for the full plant life with the operating modes presently used. one solution would be to anneal the reactor vessel such that material properties approach their original values. This solution is feasible, in principle, and could be performed with the vessel in place.

Note: Refer to Section 18.3.2.3 regarding the operation beyond the original 40-year operating licenses.

1.6.2.4 **Containment Spray Program (Item 3 of Reference 1)**

In the unlikely event of a major LOCA, one of the radiological hazards could be the release into the containment of radioactive iodine from ruptured fuel. The absorption of this iodine by a suitable chemical spray has been investigated extensively by Vepco and Westinghouse. The research and development program is discussed in WCAP-7499-L (Reference 6).

1.6.2.5 **Fuels Development Program for Operation at High Power Densities (Item 8 of Reference 1)**

As part of the program to demonstrate the satisfactory operation of fuel at high burnup and power densities, fuel was tested in both the Saxton and Jose Cabrera (Zorita, Spain) reactors. The Saxton loose-lattice irradiation program was used to demonstrate fuel performance at conditions significantly in excess of 1970 PWR design limits, and to establish power burnup limits for the fuel. The Jose Cabrera reactor was the first PWR with a Zircaloy core to operate at similar core conditions to the 1970 design units. Because of the timely manner in which fuel could be irradiated in Jose Cabrera, four fuel assemblies were tested there to demonstrate the satisfactory operation of the fuel in a commercial PWR environment.

The sustained successful operation of special Jose Cabrera fuel rods at peak design power levels (in excess of those planned for these units) also increased the assurance that the fuel had adequate performance margins to accommodate transient overpower operation.

1.6.2.6 **Incore Detector Program (Item 9 of Reference 1)**

The purpose of this program was to develop fixed incore neutron detectors suitable for the continuous monitoring of the power distribution in a PWR core.

Testing at San Onofre, the Western New York Research Reactor, the Brookhaven high flux beam reactor, and the Union Carbide (Tuxedo) reactor were used to evaluate detector performance. Tests at the Tuxedo reactor were performed for detector linearity and the optimization of design. Cables for incore detectors were also tested. Cable reliability was greatly improved in this program.

This program permitted a fixed incore flux detector system to be installed in H. B. Robinson Unit 2 and showed the acceptability of installing a system in Indian Point Unit 2. These systems serve only as an operational convenience to the plant operator and as test vehicles to evaluate the need for and suitability of incore detectors for power distribution monitoring and control. The incore detector development program was continued in the early, large plants with the principal aims of demonstrating the design lifetime of a PWR and optimizing detector parameters. Since ex-core detectors, particularly long ion chambers, have been found effective for monitoring both axial and radial gross power distribution, there were no plans to install a fixed incore system in the Surry reactors. However, provision was made so that a fixed incore detector system could be installed in the Surry reactors.

1.6.2.7 **Empire States Atomic Development Associates DNB Program (Item 11 of Reference 1)**

This program provided experimental rod bundle DNB data with non-uniform rod axial flux distributions. The program was conducted at Columbia University under the direction of WNES, Pittsburgh, Pennsylvania. The results of this program are detailed in WCAP-7411-L (Reference 7), which was submitted in July 1970. The experimental rod bundle data with non-uniform rod axial flux distributions are directly applicable to the design of this unit. The results of the program show that the W-3 DNB correlation applied in the Surry design is conservative.

1.6.2.8 **Full Length Emergency Core Cooling Heat Transfer Test (FLECHT) (Item 12 of Reference 1)**

The purpose of the FLECHT program was to investigate experimentally the thermal behavior of a simulated PWR core during the core recovery period that follows a LOCA. The first series of tests are reported in WCAP-7435 (Reference 8).

The loss-of-coolant evaluation presented in the Surry application uses conservative design assumptions in the heat transfer models for analyses of the re-flooding phase of the accident. The FLECHT program assisted in developing new analytical models to describe the core recovery phenomena. The results were favorable in 1970, at which time the program was essentially complete.

1.6.2.9 **Flashing Heat Transfer Program (Item 13 of Reference 1)**

The program is completed. It proved that the present core thermal design analysis used for evaluating the LOCA results in a conservative prediction of the peak clad temperature. The results from the program were used in the initial loss-of-coolant analysis. The program and results are summarized in WCAP-7396-L (Reference 9).

1.6.2.10 **Loss-of-Coolant Analysis Program (Item 14 of Reference 1)**

The loss-of-coolant analysis program was intended to integrate, as appropriate, the more realistic heat transfer models obtained from experimental and analytical development programs into the core thermal design codes used to evaluate the LOCA (Reference 10).

This program was completed. An evaluation of the LOCA using the results of the flashing heat transfer program in the core thermal design code is presented in WCAP-7422-L (Reference 10).

1.6.3 Assurance for Completion of Research and Development

In 1970, assurance that the necessary information would be obtained was provided by the following facts:

1. The work being done did not require development of new concepts or ideas; only the normal engineering and design work was required to complete the design.
2. Vepco and Westinghouse Electric Corporation were capable of providing necessary information in sufficient time to obtain operating licenses for the units to permit scheduled commercial operation. The research and development program was compatible with the station schedule, in that definite results would be available before the station became operational.
3. Periodic reviews of this project and other similar Westinghouse PWR projects were held with the AEC staff, as information became available, to demonstrate that the required information was being developed in a satisfactory manner.

Significant results obtained in research and development programs were formally provided to the AEC, in as timely a manner as was reasonably practicable following program completion, by the following methods:

1. Preliminary safety analysis reports on new applications.
2. Final safety analysis report on this or other applications.
3. Topical reports applicable to this and certain other applications.
4. Topical reports applicable to all applications.

1.6 REFERENCES

1. Westinghouse Electric Corporation, *Safety Related Research and Development for Westinghouse Pressurized Water Reactors - Program Summaries - Spring, 1970*, WCAP-7498-L, Westinghouse Proprietary, May 1970.
2. Westinghouse Electric Corporation, *Performance of Zircaloy Clad Fuel Rods During a Simulated Loss-of-Coolant Accident - Single Rod Tests*, WCAP-7379-L, Volume I, Westinghouse Proprietary, Volume II, Non-proprietary, September 1969.
3. Westinghouse Electric Corporation, *Performance of Zircaloy Clad Fuel Rods During a Simulated Loss-of-Coolant Accident - Multi-Rod Tests*, WCAP-7495-L, Vols. I and II, Westinghouse Proprietary.
4. Westinghouse Electric Corporation, *Loss-of-Coolant Accident: Comparison Between BLODWN-2 Code Results and Test Data*, WCAP-7401, Non-proprietary, November 1969.
5. Westinghouse Electric Corporation, *The Effects of Safety Injection on a Reactor Vessel and Its Internals Following a Loss-of-Coolant Accident*, Westinghouse Proprietary, December 1967.
6. Westinghouse Electric Corporation, *Elemental Iodine Removal by Reactive Sprays*, WCAP-7499-L, Westinghouse Proprietary.
7. Westinghouse Electric Corporation, *Rod Bundle Axial Non-Uniform Heat Flux DNB Tests and Data*, WCAP-7411-L, Westinghouse Proprietary.
8. Westinghouse Electric Corporation, *PWR Full Length Emergency Cooling Heat Transfer (FLECHT) Group I Test Report* WCAP-7435, Non-proprietary, January 1970.
9. Westinghouse Electric Corporation, *Safety Related Research and Development for Westinghouse Pressurized Water Reactors - Fall, 1969*, WCAP-7396-L, Westinghouse Proprietary.
10. Westinghouse Electric Corporation, *Westinghouse PWR Core Behavior Following a Loss-of-Coolant Accident*, WCAP-7422-L, Westinghouse Proprietary.

Surry Power Station
Updated Final Safety Analysis Report

Chapter 2

Intentionally Blank

Chapter 2: Site Characteristics
Table of Contents

Chapter 2: Site Characteristics
Table of Contents (continued)

Chapter 2: Site Characteristics
Table of Contents (continued)

Chapter 2: Site Characteristics

List of Tables

Chapter 2: Site Characteristics

List of Tables (continued)

Chapter 2: Site Characteristics

List of Figures

Chapter 2: Site Characteristics

List of Figures (continued)

Chapter 2: Site Characteristics

List of Figures (continued)

Chapter 2: Site Characteristics

List of Figures (continued)

Intentionally Blank

CHAPTER 2 SITE CHARACTERISTICS

This chapter primarily describes the site characteristics for the Surry Power Station as they existed when the facility was licensed. As such, current site characteristics may not agree with these descriptions. The site characteristics described here include geography, demographics, nearby facilities, meteorology, hydrology, geology, and seismology. This information was gathered to support or develop the original plant design bases. Chapter 2 also contains evaluations of these site characteristics demonstrating how applicable siting criteria were met at the time of original licensing of the facility. Because this information is not expected to be used to support current or future plant operations or regulatory activities, Chapter 2 does not need to be updated to reflect minor changes to these site characteristics. However, this does not preclude the need to update this chapter to reflect significant changes to this information.

In the past, minor changes to site characteristics have been incorporated into Chapter 2. While the updates were not required, these changes have not been removed. Therefore, some parts of this chapter reflect more recent information.

2.1 GEOGRAPHY, DEMOGRAPHY AND POTENTIAL EXTERNAL HAZARDS

2.1.1 Site Location and Description

2.1.1.1 Site Location

This section gives a general description of the region surrounding the Surry Power Station. Additional information can be found in the Surry Station Emergency Plan (Reference 1) and the safety analysis report (Reference 2) supporting the independent spent-fuel storage facility at for the Surry Power Station.

The Surry Power Station is located in Surry County, Virginia, on a point of land called Gravel Neck that juts into the James River from the south, as shown in Figure 2.1-1 and 2.1-16. The site is at the end of Route 650 and south of and adjacent to the Hog Island State Wildlife Management Area. It is bordered by the James River on either side of the peninsula. The site is 4.5 miles west-north-west of Fort Eustis, 7 miles south of Colonial Williamsburg, and 8 miles east north east of the town of Surry. Jamestown Island, part of the Colonial National Historical Park, is to the northwest on the northern shore of the James River.

The site coordinates are:

	Latitude	Longitude	Universal Transverse Mercator (UTM)		
Unit 1	37° 9' 58" N	76° 41' 55" W	4,114,460 mN	349,200 mE	zone 18s
Unit 2	37° 9' 57" N	76° 41' 53" W	4,114,415 mN	349,280 mE	zone 18s

The area within 10 miles of the site covers parts of Surry, Isle of Wight, York, and James City Counties, and parts of the cities of Newport News and Williamsburg. Surry and Isle of Wight Counties are predominantly rural and characterized by farmland, wood tracts of land, and marshy wetlands. York and James City Counties and the cities of Newport News and Williamsburg are more urban and are characterized by recreational areas and growing population centers. The Hog Island State Wildlife Management Area, immediately north of the site, is reached by a public access road running through the site. Public parking and viewing points are provided by the state within the refuge. The tip of the peninsula is very marshy and almost severed by many streams and creeks.

The region 10 to 30 miles east and southeast of the site is comprised of the Hampton, Newport News, Norfolk, and Portsmouth, Virginia urban areas. This general area is a major Atlantic Coast seaport and U.S. naval base, and the largest industry is shipbuilding. The site is 44 miles southeast of Richmond, Virginia. The Atlantic Ocean lies some 40 miles east of the site. Figure 2.1-2 shows the site and the general topography over an area to a radius of about 50 miles.

2.1.1.2 **Site Description**

The plant site comprises approximately 830 acres. The plant property lines, which are the same as the site boundary lines, are shown on Figure 2.1-3. Virginia Electric and Power Company (Virginia Power), owns, in fee simple, all of the land within the site boundary, both above and beneath the surface, with the exception of state route 650, which passes through the site to the Hog Island State Wildlife Management Area to the north.

The site boundary is clearly posted to ensure that it will not be transgressed by unauthorized individuals.

The ground surface at the site is generally flat, with steep banks sloping down to the river and to the low-level waterfowl refuge to the north. Station ground grade has been established at an elevation of 26.5 feet above the U. S. Coast & Geologic Survey mean sea level datum at Hampton Roads, Virginia.

Beyond the site boundaries, maximum land elevations within a 5-mile radius are generally in the range of 40 to 60 feet. Much of the region is characterized by marshes, extensive swamps, small streams, and pocosins. Water tables are very near to the surface throughout the entire area, accounting for the large amount of surface waters. Drainage throughout the area is toward Hampton Roads, on the Atlantic Ocean and near the mouth of Chesapeake Bay.

Control of law and order in Surry County is under the jurisdiction of the County Sheriff’s Department and the Virginia State Police.

Significant site structures are shown on Figure 2.1-3.

2.1.1.3 **Boundaries for Establishing Effluent Release Limits**

The release limits for liquid and gaseous effluents are based on the unrestricted areas as shown on Figure 2.1-4. For gaseous effluents, the unrestricted area is at or beyond the site boundary. For liquid effluents, the unrestricted area is at the discharge canal. Exposure of individuals to radiation in these areas will be within 10 CFR 20 limits. Since Vepco owns, in fee simple, the land within the site boundary, it has total control over access to this area. Access is controlled by the security guard force.

2.1.2 Exclusion Area Authority and Control

2.1.2.1 Authority

The Exclusion Area is the site boundary. The minimum distance from a reactor centerline to the site exclusion boundary as defined in 10 CFR 100 is 1650 ft. This is the distance for Unit 1, which is controlling and is sufficient, in conjunction with the plant design, to ensure that the dose limitations of 10 CFR 50.67 are met. Virginia Power has the authority to control activities within the Exclusion Area, including exclusion and removal of personnel and property. Virginia Power has total control over access to this area except for public access on State Route 650 to the Hog Island State Wildlife Management Area to the north of the site. A map of the site is shown in Figure 2.1-3.

2.1.2.2 Control of Activities Unrelated to Plant Operation

No activities unrelated to plant operations (other than transit through the area) are permitted in the Exclusion Area without Virginia Power approval.

2.1.2.3 Arrangements for Traffic Control

In the event of an emergency, local law enforcement officers will take control of traffic on State Route 650.

2.1.3 Population Distribution

2.1.3.1 Population Within 10 Miles

Figure 2.1-1 shows the general locations of the municipalities and other cultural features within 10 miles of the Surry site. As indicated on Figure 2.1-1, the municipalities which are wholly or partly within 10 miles of the site are:

	1990 Population[1]	Distance (miles) from Surry site	Direction from Surry site
City of Newport News	171,439	4.5 (closest point)[2]	ESE
City of Williamsburg	11,530	7	N
Town of Surry	190	8	WSW

The population distribution within 10 miles of the site was computed by overlaying 1990 census block data (Reference 3), (the smallest unit of census data), on the grid shown on Figure 2.1-1 and summing the population of the census blocks falling in each of the polar sectors comprising the grid. The population of census blocks shared by more than one polar sector was apportioned based on the fraction of the census block area in each sector.

1. Reference 3
2. Fort Eustis. This is a U. S. Army installation and not part of any local municipality.

The area of a census block is generally inversely proportional to the population of the census block. Thus, an urban census block may be geographically as small as a few city blocks. However, a sparsely populated rural census block could be several miles across, but include only several residents. As a result, any error from the allocating process should be very small. The 10 mile population distribution for 1990 is shown on Figure 2.1-5.

Population projections for the areas within 10 miles of the Surry site for the years 2000, 2010, 2020 and 2030 are given in Figures 2.1-6 through 2.1-9, even though the current license expiration dates for the two Surry units are 2052 and 2053 respectively. Population projections were based on Virginia Population Projections prepared by the Virginia Employment Commission (Reference 4). For conservatism, the projected population of polar sectors encompassing portions of more than one jurisdiction was escalated at the highest rate among the applicable jurisdictions.

The 1990 resident populations within 5 and 10 miles of Surry Power Station site were 3216 and 122,097 persons, respectively.

2.1.3.2 **Population Between 10 and 50 Miles**

Estimates of the 1990 resident population from 10 to 50 miles from the Surry site were computed using the same methodology used to develop the 10 mile population distribution. The population grid from 10 to 50 miles is shown on Figure 2.1-2 and the 50 mile population distribution for 1990 is shown on Figure 2.1-10.

Population projections for the areas between 10 and 50 miles for the years 2000, 2010, 2020 and 2030 were based on the same methodology as the 10 mile projections. These population projections are given in Figures 2.1-11 through 2.1-14.

The population contribution for the portion of northeastern North Carolina included in the 50 mile radius, which at its closest point is 42 miles from the site, was under 6000. The population growth projection was based on the adjacent Virginia jurisdictions. These jurisdictions are more urban than the included areas of North Carolina.

2.1.3.3 **Transient Population**

Information concerning transient population for the area was collected from several sources as this information is not available from the 1990 census data. The area within 10 miles of the site to the south and west is predominantly rural and characterized by farm land, wooded tracts of land, and marshy wetlands. Since there are no significant industrial or commercial facilities in these directions, and none are anticipated, the transient employment population is likely to be out of, rather than into, the area.

General transient employment population figures in the Williamsburg and Newport News areas within 10 miles of the plant are not available. However, large employers in these areas within 10 miles of the Surry site are listed in Table 2.1-1.

Transient population estimates for the tourist attractions, parks and recreational areas to the north, east and southeast are provided in Table 2.1-2. These figures were obtained from the individual attractions and the Virginia Division of Tourism (Reference 5). Total tourist figures in the Williamsburg area have not changed significantly over the last ten years. Ticket purchases at Colonial Williamsburg (Reference 6) and Jamestown and Yorktown National Historical Parks (Reference 7) have collectively decreased. Busch Gardens (Reference 8), located 5.4 miles NNE of the Surry site, and with an annual attendance of 2.1 million, is the largest single tourist attraction in the 10 mile area. Peak daily figures are estimated based on data provided by the Virginia Division of Tourism (Reference 5).

2.1.3.4 **Low Population Zone**

The Low Population Zone, as shown in Figure 2.1-1, is bounded by a 3 mile-radius circle centered at the Unit 1 reactor containment building. The Low Population Zone boundary was established to ensure that the dose limitation requirements of 10 CFR Part 100 are met.

The resident population distribution within the Low Population Zone is indicated in Figures 2.1-5 through 2.1-9 based on the 1990 census and projections every 10 years through to the year 2030. In summary, the Low Population Zone population for 1990, and the projected population through 2030, are as follows:

1990	145
2000	161
2010	174
2020	186
2030	199

The only significant sources of transient population within the Low Population Zone are noted on Table 2.1-2. Use of the Hog Island State Wildlife Management Area has remained essentially constant since the Surry Station began (Reference 9) operation. Peak annual use of the Chippoaks Plantation State Park dropped from 125,000 in 1989 to 98,000 in 1991 (Reference 10). Usage recovered to 115,552 in 1993. Future usage could be increased if additional camping facilities are added.

Considering the available road network leading from the Low Population Zone, together with the availability of private as well as public vehicles, there is reasonable assurance that these populations could be evacuated in a timely manner in the event of a design-basis accident.

2.1.3.5 **Population Center**

The nearest population center with more than 25,000 residents is the city of Newport News, which had a 1990 population of 171,439. Fort Eustis, a U. S. Army Base, which is geographically adjacent to Newport News, is within 4.5 miles of the Unit 1 reactor containment building. The closest point of Newport News proper is 7 miles east-south-east of the site. Either of these distances is greater than the population center distance, which is one and one-third times the Low

Population Zone boundary distance, as required by 10 CFR 100. In addition, the dose limitations of 10 CFR 50.67 or RG 1.183, as applicable, are met with considerable conservatism. There are no closer population centers whose population is likely to reach 25,000 by 2030.

2.1.3.6 **Population Density**

The cumulative resident population in 1990 to a distance of 50 miles in all directions from the plant is compared with the cumulative population resulting from a uniform population density of 500 people/sq. mile in Figure 2.1-15. Similarly, the projected cumulative resident population in 2030 to a distance of 50 miles in all directions from the plant is compared with the cumulative population resulting from a uniform population density of 1000 people/sq. mile.

2.1.4 Nearby Industrial, Transportation, and Military Facilities

This section evaluates the effects of potential accidents associated with present and projected nearby industrial, transportation, and military facilities.

2.1.4.1 **Location and Routes**

The James River shipping channel for ships and barges passes within 2.3 miles of the site, as shown on Figure 2.1-16. Route 650, a state secondary road, provides the only land access to the site. Portions of State Routes 10 and 31 pass within 10 miles of the site with the closest approach of State Route 10 being 4.5 miles from the site. The only railway within 10 miles is the CSXT Railway which is 6 miles to the northeast at its nearest approach to the site. The site is bordered on the east and west by the James River and is accessible by water craft at the east side pier. There are three airports within 10 miles of the site, Williamsburg-Jamestown Airport (5 miles NNW), Felker AAF (5 miles ESE), and Melville (Reference 11). There are no federal airways within 5 miles of the plant (Reference 11). There are no known mines or stone quarries within 5 miles of the site or commercial nuclear facilities within 50 miles of the site.

2.1.4.2 **Description of Facilities**

Lists of facilities and the hazardous materials they used or stored locally were obtained from local fire departments (Reference 12). There are no significant manufacturing facilities located within 5 miles of the Surry site. The closest industrial facility to the site is Anheuser-Busch, a brewery plant (5.5 miles NNE). There are no hazardous materials at the brewery that would pose a credible threat to the Surry site. BASF Corp., which operated the former Dow-Badische synthetic fibers factory 4.9 miles east-north-east, has closed the facility (Reference 13). Other significant facilities within 10 miles of the site are discussed in Table 2.1-1.

The only military installation within 5 miles of the site is the U. S. Army Transportation Center at Fort Eustis (4.5 miles east-south-east, at its closest point) (Reference 14). The U. S. Naval Reservation, including the U. S. Naval Supply Center, the U. S. Naval Weapons Station (Reference 15) and Camp Peary, occupies a large portion of the land area north and northeast of the site between the James and York Rivers. The U. S. Naval Reservation is bordered to the east-southeast by the Yorktown portion of the Colonial National Historical Park. The U. S. Naval

Weapons Station lies 6.2 miles northeast of the site. The nature of hazardous materials on these facilities is confidential. Increased activities at these facilities is not anticipated.

2.1.4.3 Pipelines

As shown on Figure 2.1-16, Columbia Gas Transmission Corporation and Colonial Pipeline Company own pipelines which cross the southeast corner of the site. A spur pipeline branches into the Surry Site from each of these lines to supply natural gas and No. 2 fuel oil, respectively, to the Gravel Neck Combustion Turbine Facility, which is located south of the intake canal. The Columbia Gas Transmission Corporation pipelines carry only natural gas and there are no plans to transport any other materials. The Colonial Pipeline Company pipeline carries No. 2 fuel oil. There are no other pipelines within 5 miles of the facility. The specifications of the pipelines are listed below (References 16 & 17).

Line	Year Built	Diameter	Max. Press.	Depth
Columbia Gas				
NW Line(1)	1960	8"	600 psi	>30"
SE Line (St. Rt. 626 to river)(1)	1971	10"	600 psi	>30"
SE Line (under river)(1)	1982	12"	600 psi	>30"
Spur to combustion turbines(2)	1969	12"	600 psi	>30"
Colonial Pipeline				
Main line(3)	1963	14" o.d.	1181 psi	>30" land >48" river
Spur to combustion turbines(4)	1990	12.75	150 psi	>30"

1. Line isolation is provided by manual gate valves at State Route 626 and both sides of the river.
2. Line isolation is provided by manual gate valves at the junction with the transmission pipelines.
3. Line isolation is provided by slab gate valves on each side of the river.
4. Line isolation is provided by a slab gate valve at the junction with the transmission pipeline.

2.1.4.4 Waterways

The James River, a major waterway with a 25-foot-deep channel, is navigable by seagoing vessels up to Richmond. A survey of dock facilities upstream of the Surry site was conducted to identify potentially hazardous materials transported past the site. Two categories of vessels use the river, closed container ships and bulk carriers. The container ships carry no Class 1[1] hazardous materials. Other hazardous materials are double contained and quantities are generally small. They are packed in drums or packages that are consolidated in large closed containers. Container ships pass the site about 80 times per year. Shipment frequency is not expected to increase in the near future (Reference 18).

The only potentially explosive hazardous material routinely shipped in bulk is “interface” which is a mixture of gasoline and diesel oil that represents the transition between batches of

1. International Maritime Dangerous Goods (IMDG) Code, Hazardous Materials Classification Section

gasoline and diesel oil in a pipeline. Interface is shipped in 30,000 bbl (1.3 million gallon barges). These shipments occur several times a month (Reference 19). Other materials, such as phenol, which is shipped in 5.5 million lb lots every few days, and occasional 2000-ton shipments of sulfuric acid are also transported past the site (Reference 20). Other flammable, non-explosive materials include asphalt and No. 6 fuel oil.

One facility shipped a number of barges containing up to 100,000 bbl (4.2 million gallons) of gasoline as recently as December 1991 before the dock was closed. The dock was reopened for one 100,000 bbl shipment in November 1993. However, the operator expects no future shipments and is considering closing the dock permanently (Reference 21).

Chemical compounds shipped along the James River are listed in Reference 22. Quantities and types of materials currently being shipped are similar.

The nearest point of the shipping channel is approximately 1.4 miles from the intake structure. In addition, the river depth at mean high tide for much of the distance between the intake structure and the channel is four feet or less. As a result, shipping on the James River does not constitute a hazard to the intake structure.

2.1.4.5 **Roads**

State secondary Route 650 is the only land access to the Surry site. It ends at the Hog Island State Wildlife Management Area, north of the site. No chemicals or cargo are expected to be transported on this portion of Route 650 unless the chemicals are used by the Surry Power Station. Chemicals stored onsite and evaluated for control room habitability are listed in Table 2.1-4.

Virginia Highway 10 is the only other primary state route that passes within 5 miles of the site. A list of chemical compounds transported on a regular basis by truck on Virginia Highway 10 in 1981 is also provided in Reference 22. This list was revalidated in 1994. This list does not include shipments of small amounts of chemical compounds shipped to and used by the local farmers and merchants in Surry and Isle of Wight Counties.

2.1.4.6 **Airports**

There are two airports that are just over 5 miles from the site which can be seen on Figure 2.1-17. Information on these airports was obtained from the Virginia Division of Aviation and the individual airports. Williamsburg-Jamestown Airport, 5 miles north-north-west, has a 3200-foot paved runway. There is no control tower. Operations primarily involve single engine light planes and a small number of business jets. The trend of operations over the past few years is essentially flat with approximately 17,000 operations per year. Forty-five planes were based at the airport in 1993. The traffic patterns at the airport are to the southwest and do not normally involve passing over the river (Reference 23).

Felker AAF at Fort Eustis is 5 miles east-south-east of the site. This facility maintains a control tower and has a 3000-foot paved runway. Traffic at Felker is primarily U. S. Army helicopters. There is also a flying club that operates light planes out of the facility. Helicopter operations are expected to decrease by 20% following transfer of certain training functions to another facility. Direct over flight of the station below 1500 feet is prohibited. Base legs and cross wind legs are three statute miles from the station (Reference 14).

Melville Airfield is a private grass strip about 6 miles west-south-west of the site. Only one plane is based there and the facility appears to see little use (Reference 24).

None of the airports expect significant facility changes that would affect use. No large commercial jets use any of these facilities. These and other airports potentially affecting the site are listed in Table 2.1-3.

2.1.4.7 **Projections of Facility Growth**

Given their rural nature, none of the facilities in Surry or Isle of Wight Counties are expected to change in the near future.

2.1.5 Evaluation of Potential Accidents

2.1.5.1 **Explosions and Flammable Vapor Clouds**

Possible sources of explosion and formation of flammable vapor clouds include the natural gas or No. 2 fuel oil carried by the pipelines passing near the site or explosive materials/chemicals used by nearby industrial facilities, carried by truck traffic on Virginia Highway 10, or carried by waterborne traffic on the James River.

2.1.5.1.1 Truck Traffic

As shown in Reference 22, the largest explosive load transported on Highway 10 contains 8500 gallons of gasoline. The explosive force of this quantity of gasoline is estimated to be equivalent to 50,700 lb of TNT using a simple TNT equivalent yield formula (Reference 25).

According to NRC Regulatory Guide 1.91 (Reference 26), if this amount of gasoline were to explode, a peak overpressure of 1 psi would be experienced about 1900 feet away from the point of explosion; whereas, the closest approach of Highway 10 to the site is 4.5 miles. The value of 1 psi is cited by Regulatory Guide 1.91 as a conservative value of peak positive incident overpressure below which no significant damage would be expected.

Flammable vapor clouds formed from a spill of gasoline on the highway do not present an explosive hazard because gasoline vapor clouds are not known to detonate in unconfined areas (References 27, 28 & 30).

2.1.5.1.2 Waterborne Traffic

Traffic on the James River is confined to a dredged ship channel which is approximately 2.3 miles distant from the Unit 1 containment. Interface product, carried by barge, is the only chemical transported on the river that would present a potential explosion hazard. These shipments are limited in frequency to several per month.

Since interface product is a mixture of gasoline and diesel fuel, it is less explosive than pure gasoline. Conservatively assuming the whole barge is filled with 1,300,000 gallons of gasoline, and is involved in an explosion, the explosive force generated by this quantity of gasoline is estimated to be equivalent to 7,760,000 pounds of TNT (Reference 25).

Regulatory Guide 1.91 (Reference 26) indicates an overpressure of 1 psi would be experienced about 8000 feet (1.6 miles) downwind of the explosion.

2.1.5.1.3 Industrial Facilities

As noted in Table 2.1-1, with the closure of the BASF fiber facility, the only offsite industrial facility within 5 miles of the Surry site using potentially explosive materials is the Propane Air Facility operated by Virginia Natural Gas which is 5 miles to the east-north-east. The propane is contained in buried tanks and does not represent a credible danger to the Surry Station (Reference 29).

The Gravel Neck Combustion Turbine Facility is located within the site boundary south of the intake canal. (See Figure 2.1-3.) The facility can burn either natural gas or No. 2 fuel oil which are fed into the facility through underground pipelines. The facility includes six (6) combustion turbines and has the capability to store approximately 6.5 million gallons of No. 2 fuel oil in three (3) above ground tanks. The facility is equipped with fire protection and fire suppression systems. The following features also help ensure that a fire at Gravel Neck will not adversely affect the Surry Power Station:

1. The Gravel Neck facility is located more than 2000 feet from the Surry Units with the intake canal separating them.
2. The fuel oil from a failed fuel oil storage tank would be contained by the dikes around the tanks.
3. The Gravel Neck facility is located more than 700 feet from the switchyard, over 200 feet from the transmission lines and over 1200 feet from the intake canal.

In addition, the flash point of the No. 2 fuel oil precludes the fuel from exploding under anticipated site conditions.

The combustion turbine casings are designed to contain the fragments of the rotor and associated blading should they fail. This eliminates external missile generation from the Gravel Neck site as a concern.

2.1.5.1.4 Pipelines

Pipeline locations are shown in Figure 2.1-16. An explosion of natural gas occurring in the pipelines is considered to be impossible due to the absence of oxygen. However, potential explosions may result from ruptured or leaking pipelines. As indicated in Regulatory Guide 1.91 (Reference 26), for an overpressure of about 1 psi to be experienced in the vicinity of the nuclear containments, in excess of the equivalent of 25,000 lb TNT of explosive material would be required.

The amount of natural gas, which would produce an explosive force equivalent to 25,000 lb TNT, corresponds to the contents of a 2.6-mile section of the pipe. In the case of a leaking pipeline, any potential explosion will not involve the whole quantity of the natural gas within the pipeline. This is because the natural gas will be dispersed and carried downwind by the ambient wind as soon as it leaks from the pipeline. For the case of a postulated ruptured pipeline, assuming the whole quantity is involved in an explosion and natural gas is escaping at sonic velocity, it will take more than 12 seconds to empty a 2.6-mile pipe section. The natural gas cloud will eventually occupy a volume of 450,000 ft^3 without wind advection. If the gas cloud is advected by a very low wind, i.e., 1 meter per second, the elongated gas cloud will have a diameter of 135 feet. Since an unconfined natural gas vapor cloud is not known to explode (References 27, 28 & 30), and the assumption of an explosion event involving the entire contents of a 2.6-mile section of a natural gas pipeline is a very conservative assumption, the pipelines are not considered a significant hazard to plant operation.

The pipeline carrying No. 2 fuel oil is not considered an explosion hazard due to its flashpoint as discussed in Section 2.1.5.1.3 above.

2.1.5.2 **Toxic Chemicals**

Potentially toxic chemicals associated with control room habitability and currently stored onsite are listed in Table 2.1-4. The list is comparable to that used for the Toxic Release Evaluation reported in Reference 31 and the chemical storage analysis in Reference 35. The effects of Halon release on control room habitability are discussed in Section 9.10.2.2.9 of the UFSAR. The quantity of dimethylamine is limited to 100 pounds (825 gallons of 2% solution) so as to not impact control room habitability as described in Regulatory Guide 1.78.

2.1.5.3 **Aircraft Accidents**

The crash probability due to the flights passing near the Surry site from either of the two airports 5 miles from the site, Felker AAF and Williamsburg-Jamestown Airport, was reported in NUREG/CR-4550 (Reference 32) as about 1×10^{-6} per year, based on an assumed combined operations of 126,500 per year. Based on current actual annual operations of 101,000, the revised crash probability is 8.2×10^{-7}. The majority of the general aviation operations from the two airports involve single engine light aircraft weighing less than 4000 lb, with 10% of the Williamsburg operations involving twins and small jets weighing less than 12,500 lb. Such small aircraft pose a minimal risk to the plant.

Melville, which lies 6 miles west-south-west of the site, is a private field with a 2900-foot unpaved runway. Use of the airfield is limited to a low volume of small aircraft. Any aircraft accident probability due to operation of Melville airfield will be less than the probability due to operation of the two airports analyzed. There are no other airfields within 10 miles of the site.

Newport News/Williamsburg International Airport (Formerly Patrick Henry), 11 miles east-southeast of the site, is an international airport with 172,000, 109,000 and 180,000 operations in 1983, 1988 and 1993, respectively. In 1993 approximately 37,000 involved commercial aircraft (Reference 33). Based on NUREG-0800 (Reference 34), the probability of a aircraft accident occurring at the Surry site from commercial traffic associated with this airport is estimated to be 1.3×10^{-7} per year. Airports/airfields further away from the site are not considered to be significant in the aircraft accident probability analysis.

2.1 REFERENCES

1. Surry Power Station Emergency Plan, Virginia Electric and Power Company, January 1, 1994, Rev. 36.
2. Virginia Electric and Power Company, *Dry Cask Independent Spent Fuel Storage Installation,* Surry Power Station, Safety Analysis Report, Volumes 1 and 2, October 1982.
3. U.S. Department of Commerce, Bureau of the Census, *1990 Census of Population, Number of Inhabitants.*
4. Virginia Population Projections 2010, with Supplemental projections for 2020 and 2030. Virginia Employment Commission, June 1993.
5. Virginia Division of Tourism; Mark Brown, Analyst; meeting with D. Hostetler, Grove Engineering, 2/25/94; Fax, 3/7/94.
6. Colonial Williamsburg; Jayma Thibault, Office Manager, Visitors Center; Telecon with Brent Christ, Grove Engineering, 3/10/94.
7. Colonial National Historical Park; Kirk Kehrberg, Interpretive Support Specialist; Fax to Brent Christ, Grove Engineering, 3/10/94.
8. Busch Gardens; Cindy Lemke, Public Affairs; Telecon with Brent Christ, Grove Engineering, 3/9/94.
9. Hog Island State Wildlife Management Area; Clyde Abernathy, Refuge Manager; Telecon with D. Hostetler, Grove Engineering, 2/25/94.
10. Chippokes Plantation State Park; Mary Lou Devincenzi, Program Manager; Telecon with Brent Christ, Grove Engineering, 3/9/94.
11. NOAA, Washington, Sectional Aeronautical Chart, 54th Edition, August 19, 1993.
12. James City County; Trent Funkhouser, Director of Economic Planning; Meeting with Brent Christ, Grove Engineering, 2/25/94.

13. BASF Corp.; Thomas Johnson, Coordinator; letter to Mr. Richard Miller, James City County Fire Department, dated February 7, 1994.
14. Fort Eustis; Ronald A. Johnson, Public Affairs Officer; letter dated March 10, 1994, letter dated April 13, 1994.
15. U.S. Naval Weapons Station; Tom Black, Public Affairs Officer; Telecon with Brent Christ, Grove Engineering, 3/9/94.
16. Columbia Gas Transmission Corp.; Floyd Goodwin, Area Superintendent; letter dated March 3, 1994; telecon with D. Hostetler, Grove Engineering, 4/14/94.
17. Colonial Pipeline Company; D. A. Barrett, Area Engineer; Letter dated April 14, 1994, telecon with D. Hostetler, Grove Engineering, 4/22/94.
18. Independent Container Lines; Thomas Kennedy, V.P., Marine Operations; meeting with Brent Christ, Grove Engineering, 2/16/94.
19. Primary Oil; Judy Reed, Transportation; Telecon with D. Hostetler, Grove Engineering, 3/17/94.
20. Allied Signal; Randy King, Transportation; Telecon with D. Hostetler, Grove Engineering, 3/17/94.
21. Exxon; Bill Bays, Terminal Superintendent; Telecon with D. Hostetler, Grove Engineering, 3/17/94.
22. NUS Corporation, Surry Offsite Toxic Chemical Release Analysis, Rockville, Maryland, June 1981.
23. Williamsburg Jamestown Airport; Jean Waltrip, Airport Manager; Telecon with Brent Christ, Grove Engineering, 3/9/94, Fax, 4/10/94.
24. Melville Airfield; Mrs. William E. Savage, Owner; Telecon with Brent Christ, Grove Engineering, 3/9/94.
25. W. C. Brasie and D. W. Simpson, *Guidelines for Estimating Damage from Explosions*, Chemical Engineering Process, American Institute of Chemical Engineers, 1968.
26. U.S. Nuclear Regulatory Commission, Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants, Regulatory Guide 1.91, Rev. 1, February 1978.
27. U.S. Coast Guard, CHRIS: Hazardous Chemical Data, 1978.
28. V. C. Marshall, *Unconfined Vapor-Cloud Explosions*, Chemical Engineering, June 14, 1982.
29. Virginia Natural Gas, Ann Chamberlain, Vice President Telecon with D. Hostetler, Grove Engineering, 3/17/94.

30. U.S. Nuclear Regulatory Commission, Safety Evaluation Report, Tennessee Valley Authority, Hartsville Nuclear Plant A and B, NUREG-0014, April 8, 1976.

31. NUS Corporation, Surry Onsite Toxic Chemical Release Analysis, Rockville, Maryland, January 1981.

32. U.S. Nuclear Regulatory Commission NUREG/CR-4550, Vol. 3, Rev 1, Part 3, *Analysis of Core Damage Frequency*: Surry Power Station, Unit 1; Dec. 1990.

33. Newport News/Williamsburg International Airport; John Mahaphy, Airport Manager; Telecon with Brent Christ, Grove Engineering, 3/9/94, Telecon with D. Hostetler Grove Engineering, 4/11/94.

34. U.S. Nuclear Regulatory Commission, Reactor Safety Study, *An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants,* NUREG-0800, July 1981.

35. Dominion Calculation, ME-0655, Rev. 0 and Addendums, "SPS Chemical Storage Analysis."

2.1 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FY-1D	Plot Plan

Table 2.1-1
MAJOR MILITARY, COMMERCIAL AND INDUSTRIAL FACILITIES

Facility	Location[a]	Emp.	Primary Functions	Comments
Within Low Population Zone (3 miles)				
Gravel Neck Combustion Turbine Facility	2000 feet SW		Power generation	Alternate fuels, natural gas and #2 fuel oil
Within 5 miles				
Fort Eustis	4.5 miles ESE	18,200	U.S. Transportation Center	Recent peak employment was 15,090 in 9/93
Within 10 miles				
Virginia Natural Gas Propane-Air Plant	5 miles ENE		To provide supplemental gas during times of peak load	Liquid Propane stored in underground tanks
Anheuser Busch Brewery[b]	5.4 miles NNE	1100	Beer brewery	Adjacent to Busch Gardens
Busch Gardens	5.4 miles NNE	3000	Amusement park	
U.S. Naval Weapons Storage Facility	6.2 miles NE	2650	Storage of naval weapons	
Colonial Williamsburg[b]	7.4 miles N	3000	Historical preservation	Includes volunteer workers

a. Closest point

b. Substantial overlap in annual attendance very likely because of close proximity of attractions. Total annual visitors to the Williamsburg area, including shoppers who do purchase tickets to the attractions, are estimated at 5,000,000

Table 2.1-2
TOURIST ATTRACTIONS, PARKS AND RECREATIONAL AREAS

Facility	Location	Annual Usage[a]	Peak daily[a]	Comments
Within Low Population Zone (3 miles)				
Chippokes Plantation State Park	2.5 miles SW	115,552	14,000	Peak daily use is during 2-day annual Pork, Peanut and Pine Festival (July)
Hog Island State Wildlife Management Area	Adjacent to and north of site	25,000	N/A	Visitors to view wildlife. Primarily over winter months
Waterfowl Refuge, harbors wild geese, ducks, deer and cranes, as well as other species of wildlife.		4000		Hunters, by permit only during hunting season of less than 15 days during Nov., Dec., and Jan. (Estimates by Refuge Manager)
Within 5 miles				
Jamestown Colonial National Historical Park[b]	3.1 miles NW (Closest point)	300,000	1400	Open year round (Probably includes same peak daily visitors as Jamestown Settlement)
Bacons Castle	4.2 miles SSW	6500	50	Open April through October, weekends only, March and November. Closed December
Carters Grove Plantation[b]	4.9 miles NE	259,000	2000	

a. 1993 unless otherwise noted

b. Substantial overlap in annual attendance very likely because of close proximity of attractions. Total annual visitors to the Williamsburg area, including shoppers who do purchase tickets to the attractions, are estimated at 5,000,000

Table 2.1-2 (CONTINUED)
TOURIST ATTRACTIONS, PARKS AND RECREATIONAL AREAS

Facility	**Location**	**Annual Usage**[a]	**Peak daily**[a]	**Comments**
Within 10 miles				
Busch Gardens[b]	5.4 miles NNE	2.1 million	18,000	Open April and October on weekends, May through September full time
Jamestown Settlement[b]	6.2 miles NW	373,000	1750	Open year round (Probably includes same peak daily visitors as Jamestown Colonial National Historical Park)
Colonial Williamsburg[b]	7.4 miles N	909,000	4000	Open year round. Only includes ticket purchases, i.e. does not include non-paying visitors to the area
Water Country[b]	7.5 miles NNE	460,000	5000	Open late May through Labor Day
Yorktown Colonial National Historical Park	9.2 miles ENE (Closest point)	310,000	1450	

a. 1993 unless otherwise noted

b. Substantial overlap in annual attendance very likely because of close proximity of attractions. Total annual visitors to the Williamsburg area, including shoppers who do purchase tickets to the attractions, are estimated at 5,000,000

Table 2.1-3
AIRPORTS WITHIN 20 MILES OF THE SITE

Airport	Type	Distance (miles)	Sector	No. of Operations: Comm. (1993)	No. of Operations: Total (1993)	kd^2 [a]	Longest Runway: Orient.	Longest Runway: Length (feet)	Comments
Felker AAF	Military	5	ESE	None	83,000	12,500	NW-SE	3000	72,000 rotary 11,000 light plane[b]
Williamsburg-Jamestown	Civil	5	NNW	None	18,000	12,500	NW-SE	3200	All small aircraft[c]
Melville	Private	6	WSW	None	Few	18,000	SSW-NNE	2900	Unpaved strip, no facilities, no planes based there
Newport News/ Williamsburg (was Patrick Henry)	Civil	11	ESE	37,000	180,000	121,000	SW-NE	8000	Nearest facility serving commercial jets
Langley AFB	Military	19	ESE	None	Not Avail.	361,000	WSW-ENE	10,000	Data on operations not available

a. 10 miles k = 500 < 10 miles k = 1000

b. Light aircraft are virtually all single engine aircraft weighing less than 4000 lb used by a local flying club. Helicopters currently use range in weight from 3200 lb to 55,000 lb. However, all but two types will be transferred to another facility. The combined annual operations for the two remaining types, UH-1, Huey at 9500 lb and UH-60, Blackhawk at 22,000 lb, are projected to be about 58,000.

c. Operations for 1991, 1992 and 1993 were 17,000, 18,000 and 15,600 respectively. The highest figure was entered in this table. 90% of the operations involve single engine aircraft typically weighing 2000 lbs. with some up to 4000 lb. The remaining operations involve twins and small jets weighing less than 12,500 lb, the runway limit.

Table 2.1-4
SURRY ONSITE CHEMICALS (Largest Individual Container)

Chemical	Quantity
Gasoline	4000 gal
Halon	7400 lb
Sulfuric acid	9000 gal
Ammonium hydroxide	1800 gal
Carbon dioxide	17 tons
No. 2 fuel oil	6,700,000 gal
Hydrazine	345 gal
Biocide (Bromochloro-5, 5-Dimethylhdantoin)	1000 lb
Ethanolamine	1500 gal
Sodium bromide (40%)	3000 gal (6000 gal total)
Sodium hypochlorite (15%)	3000 gal (18,000 gal total)
Dimethylamine (2%)	350 gal

Figure 2.1-1
TEN MILE SURROUNDING AREA

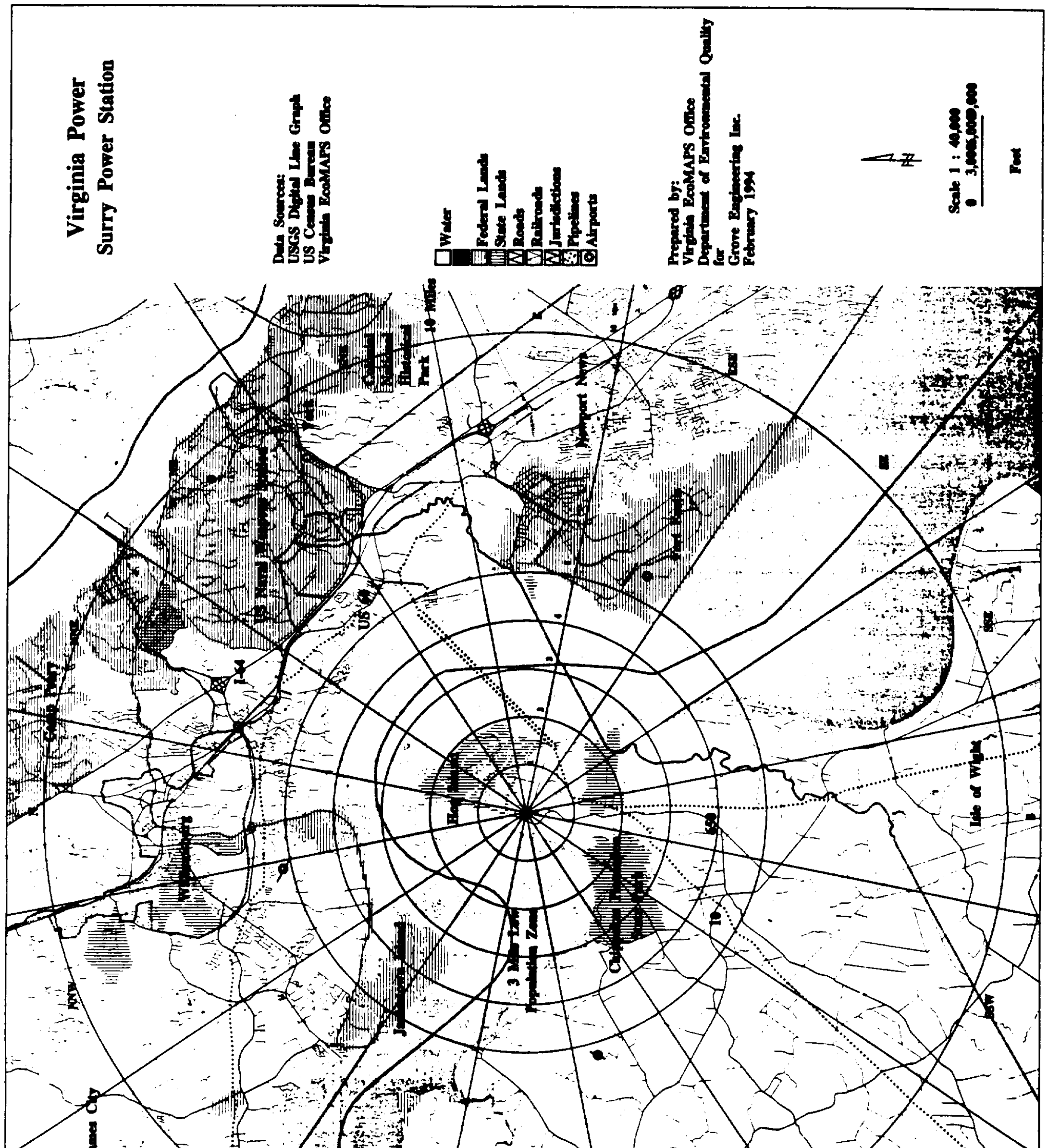


Figure 2.1-2
FIFTY MILE SURROUNDING AREA

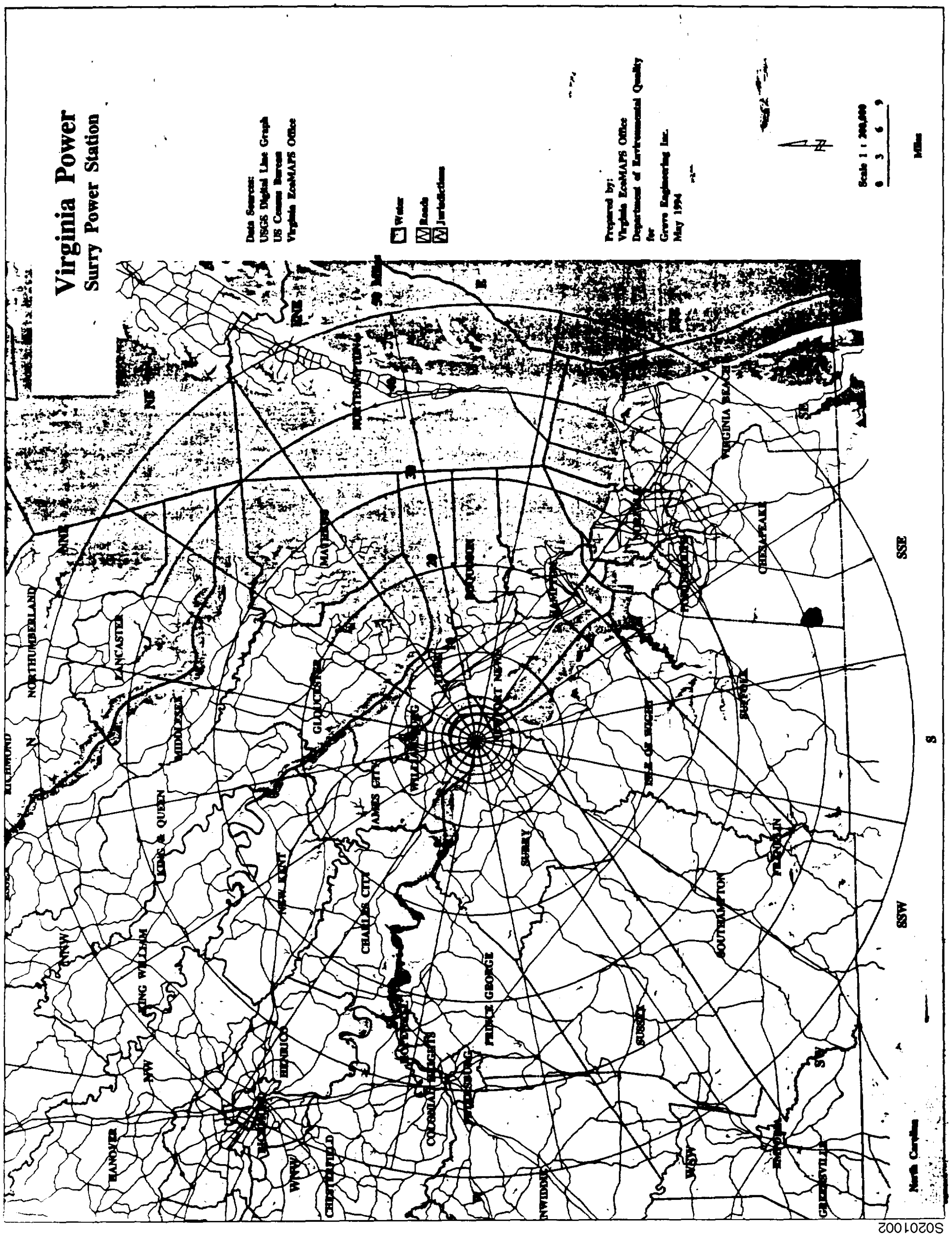


Figure 2.1-3
SITE BOUNDARY AND MAJOR STRUCTURES

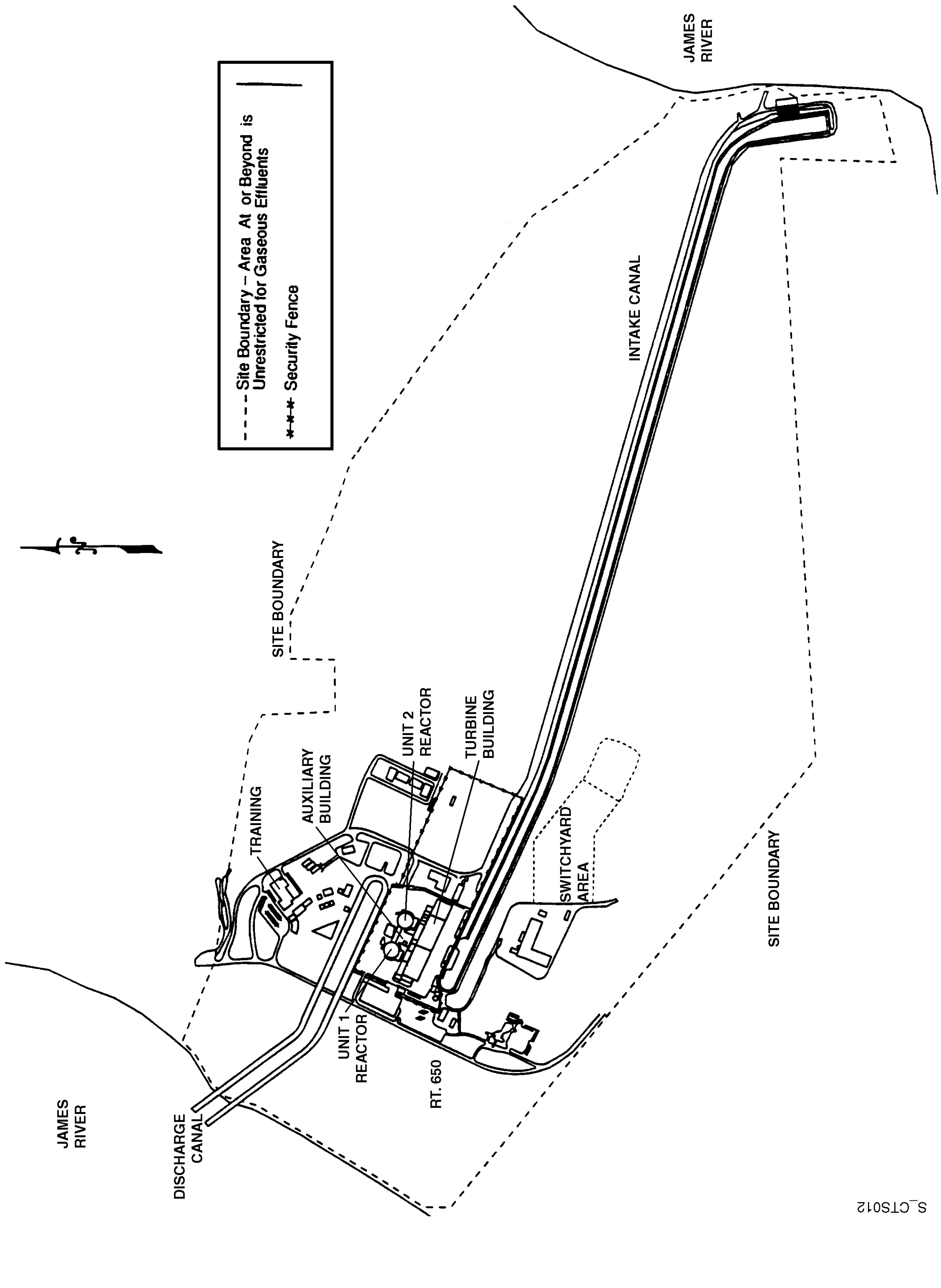


Figure 2.1-4
SITE BOUNDARY AND UNRESTRICTED AREAS

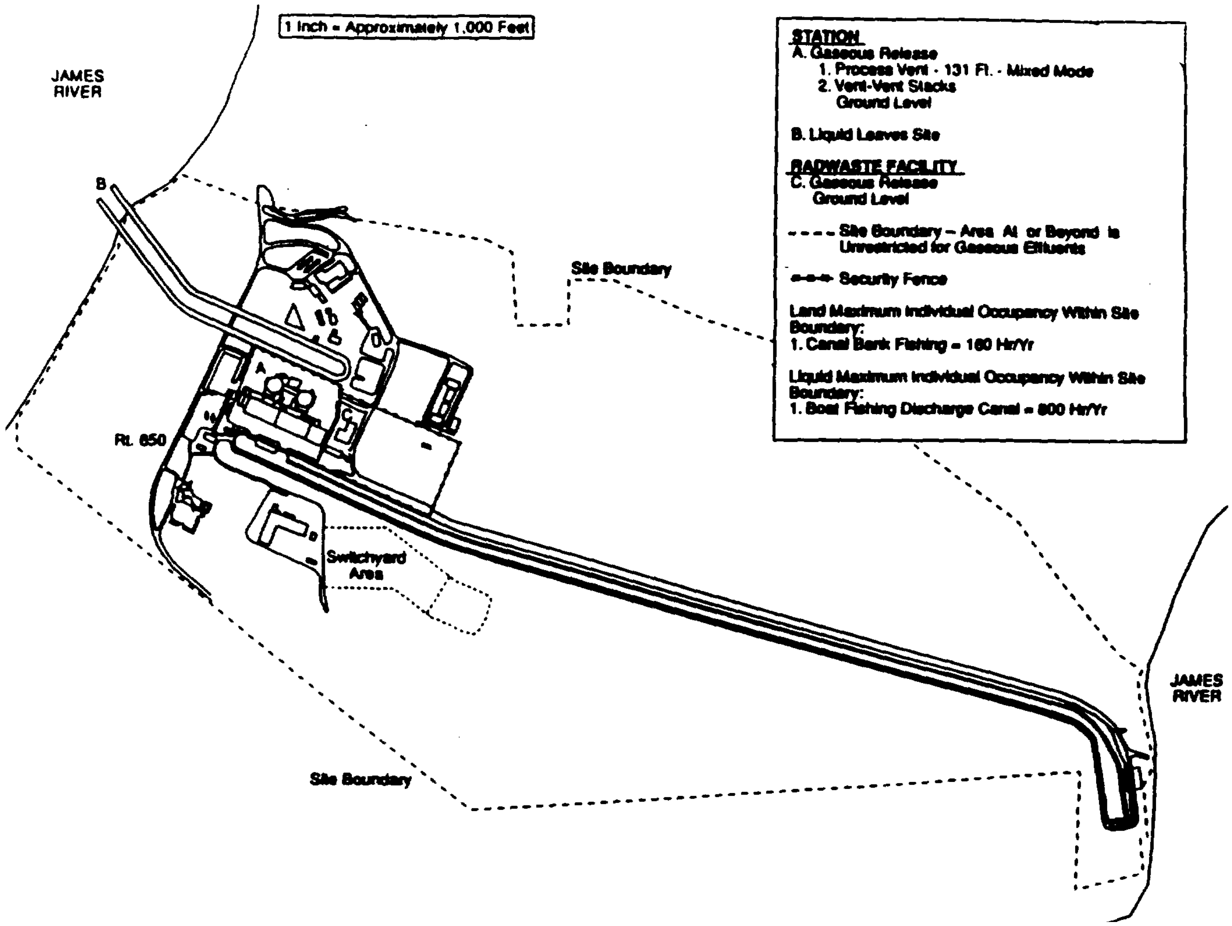
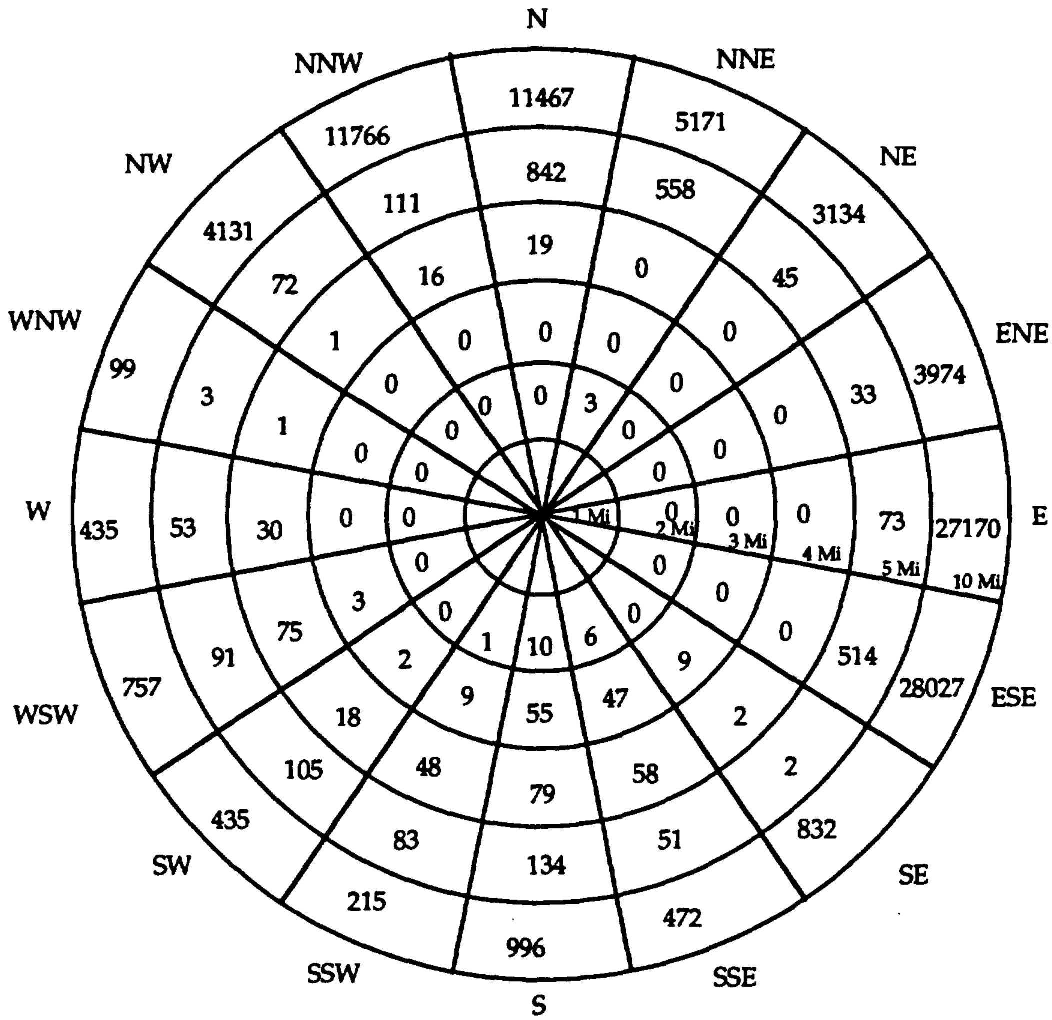


Figure 2.1-5
10 MILE POPULATION DISTRIBUTION- 1990



POPULATION INSIDE ONE MILE

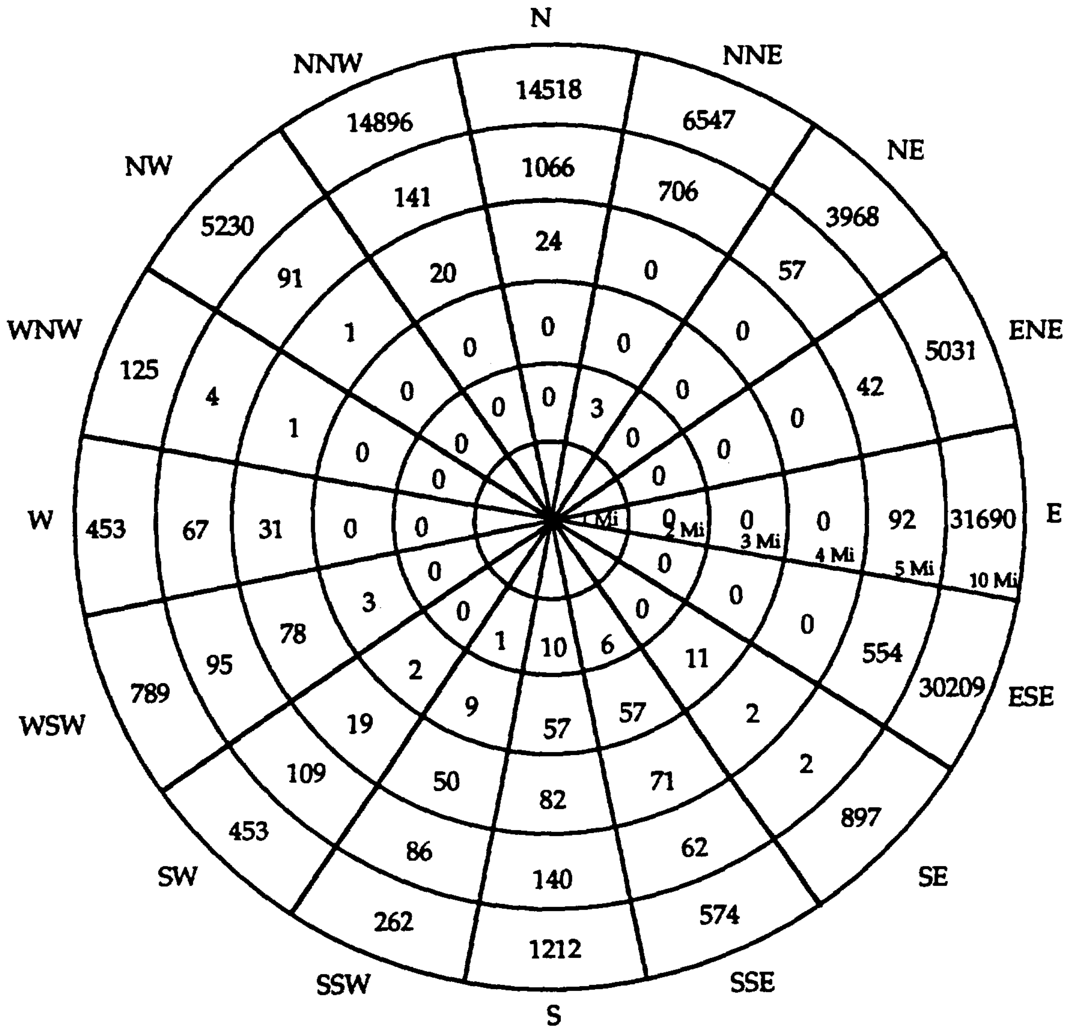
N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
S	SSW	SW	WSW	W	WNW	NW	NNW

POPULATION BY ANNULUS

ANNULUS	0 TO 1	1 TO 2	2 TO 3	3 TO 4	4 TO 5	5 TO 10	TOTAL
POPULATION	0	20	125	347	2,770	99,081	102,343

S0201005

Figure 2.1-6
10 MILE POPULATION DISTRIBUTION - 2000



POPULATION INSIDE ONE MILE

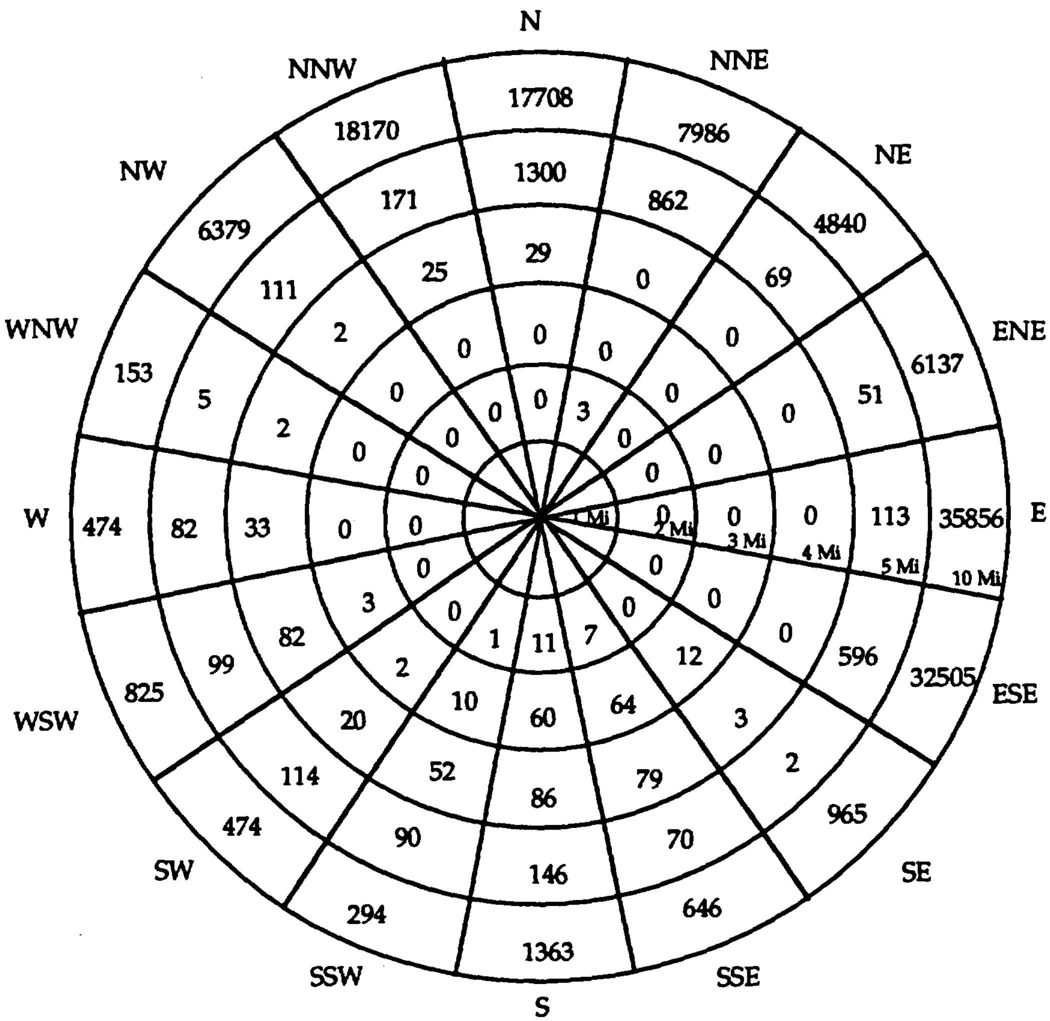
N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
S	SSW	SW	WSW	W	WNW	NW	NNW

POPULATION BY ANNULUS

ANNULUS	0 TO 1	1 TO 2	2 TO 3	3 TO 4	4 TO 5	5 TO 10	TOTAL
POPULATION	0	21	140	380	3,315	116,854	120,710

S0201006

Figure 2.1-7
10 MILE POPULATION DISTRIBUTION - 2010



POPULATION INSIDE ONE MILE

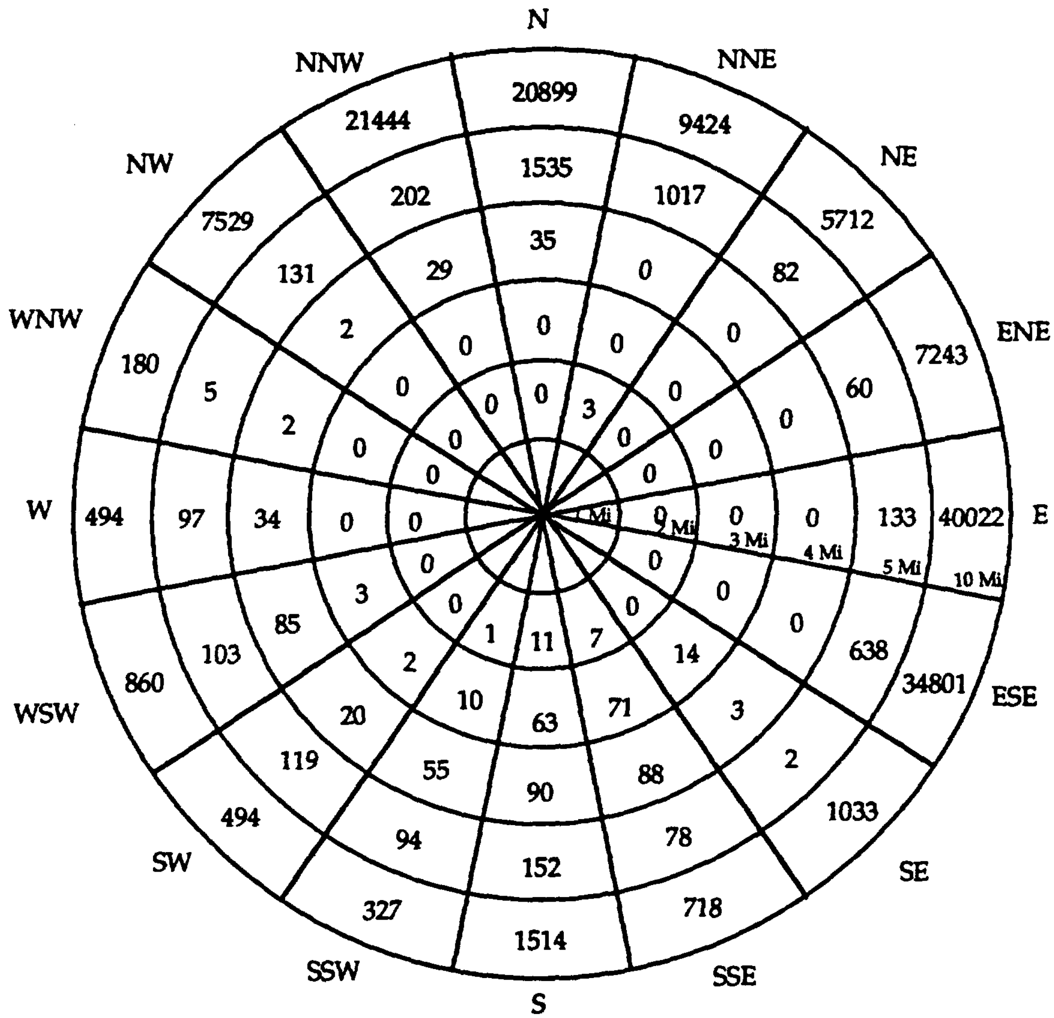
N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
S	SSW	SW	WSW	W	WNW	NW	NNW

POPULATION BY ANNULUS

ANNULUS	0 TO 1	1 TO 2	2 TO 3	3 TO 4	4 TO 5	5 TO 10	TOTAL
POPULATION	0	22	152	412	3,882	134,775	139,242

S0201007

Figure 2.1-8
10 MILE POPULATION DISTRIBUTION - 2020



POPULATION INSIDE ONE MILE

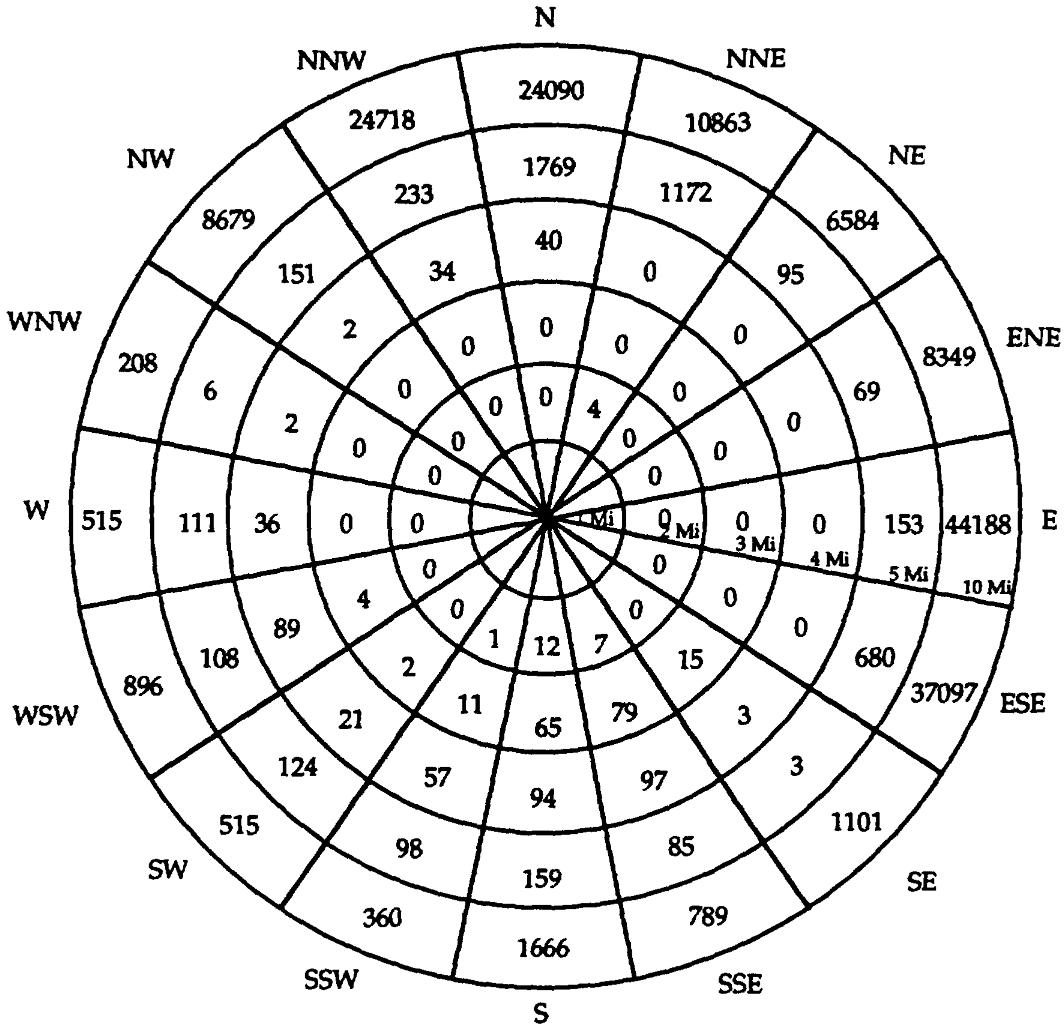
N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
S	SSW	SW	WSW	W	WNW	NW	NNW

POPULATION BY ANNULUS

ANNULUS	0 TO 1	1 TO 2	2 TO 3	3 TO 4	4 TO 5	5 TO 10	TOTAL
POPULATION	0	23	164	443	4,450	152,696	157,775

S0201008

Figure 2.1-9
10 MILE POPULATION DISTRIBUTION - 2030



POPULATION INSIDE ONE MILE

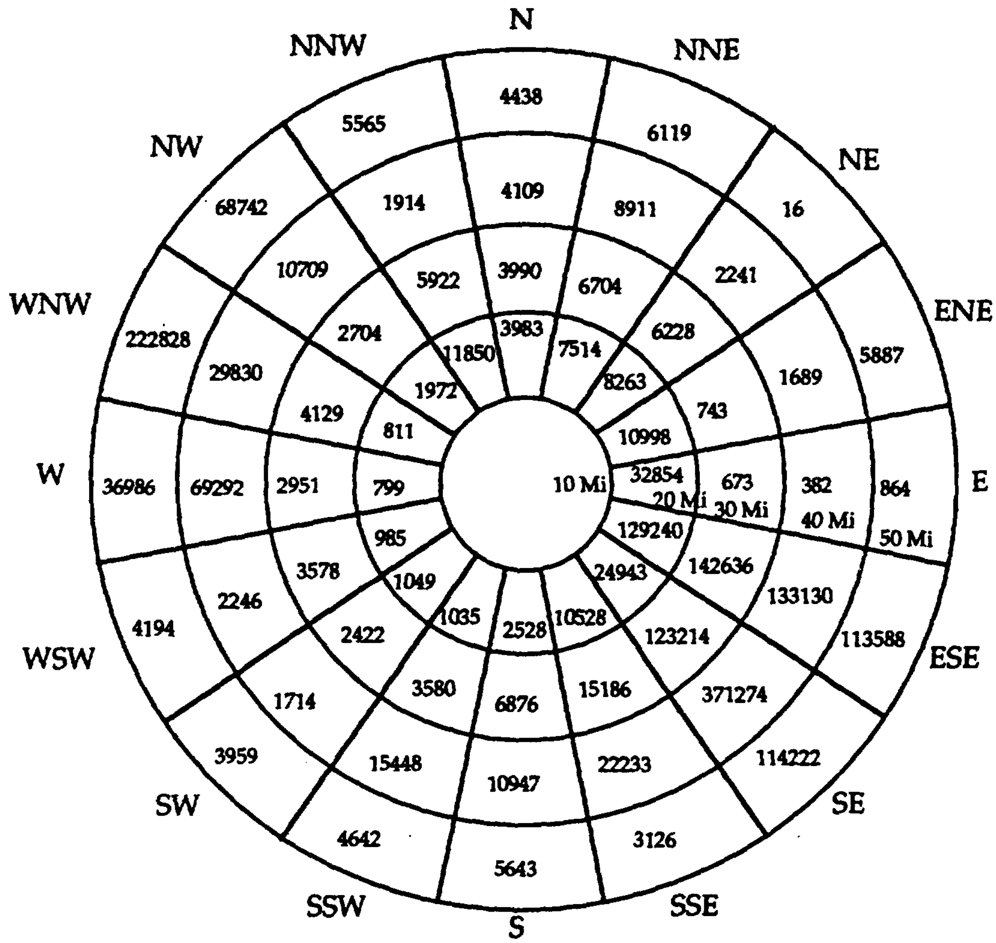
N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
S	SSW	SW	WSW	W	WNW	NW	NNW

POPULATION BY ANNULUS

ANNULUS	0 TO 1	1 TO 2	2 TO 3	3 TO 4	4 TO 5	5 TO 10	TOTAL
POPULATION	0	24	175	474	5,018	170,617	176,308

S0201009

Figure 2.1-10
50 MILE POPULATION DISTRIBUTION - 1990

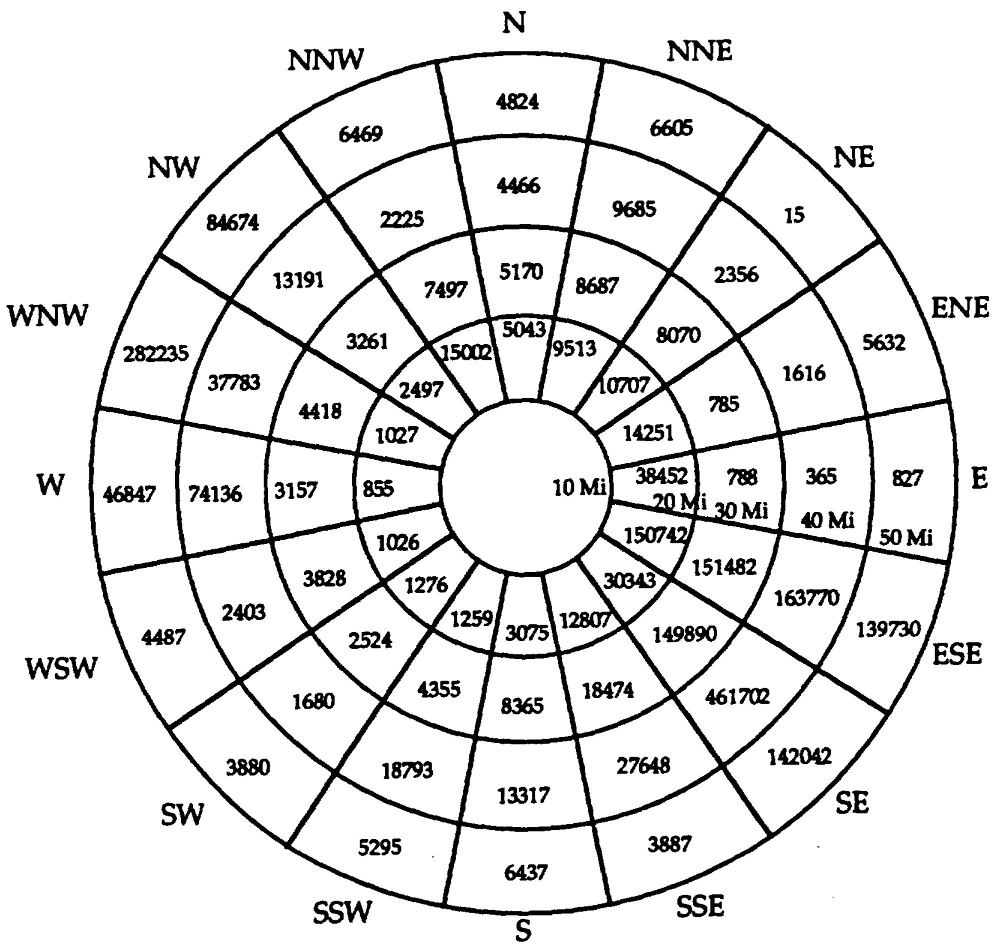


POPULATION BY ANNULUS

ANNULUS	0 to 10	10 TO 20	20 TO 30	30 TO 40	40 TO 50	TOTAL
POPULATION	102,343	249,352	331,536	686,069	600,819	1,970,119

S0201010

Figure 2.1-11
50 MILE POPULATION DISTRIBUTION - 2000

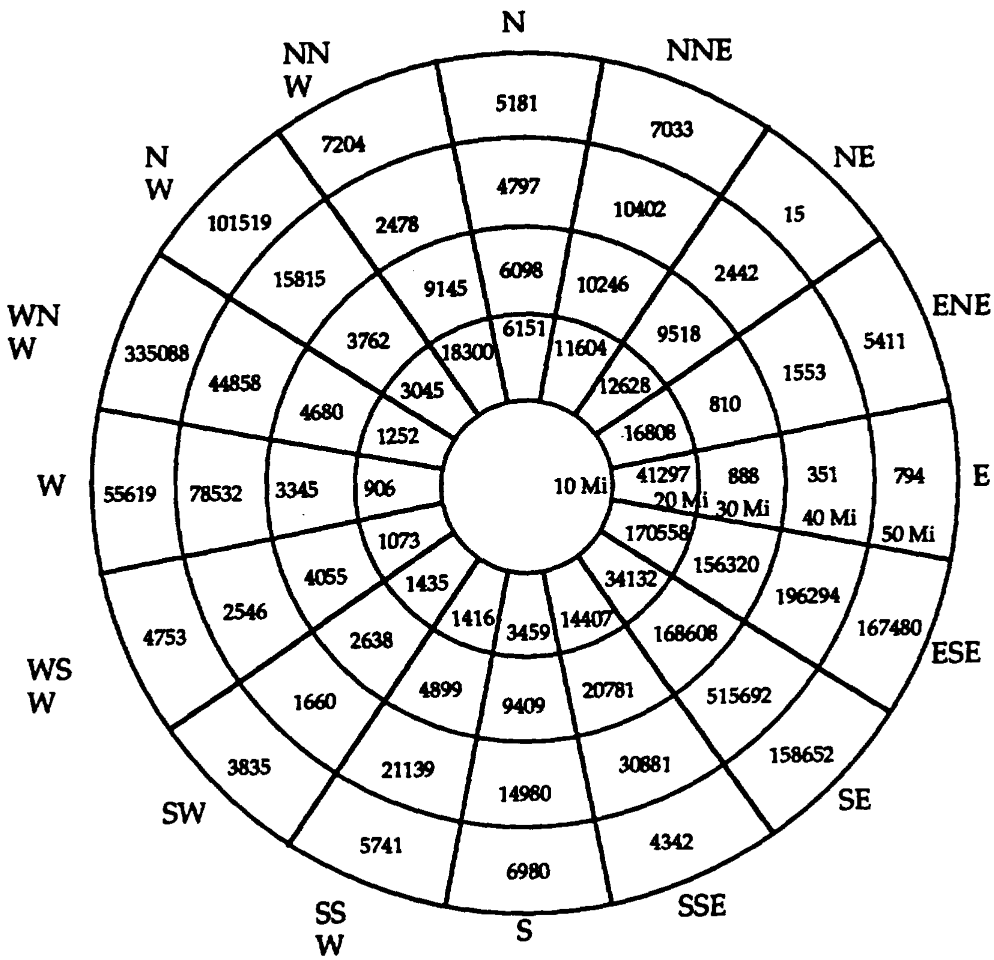


POPULATION BY ANNULUS

ANNULUS	0 TO 10	10 TO 20	20 TO 30	30 TO 40	40 TO 50	TOTAL
POPULATION	120,709	297,875	380,744	835,137	743,888	2,378,353

S020101

Figure 2.1-12
50 MILE POPULATION DISTRIBUTION - 2010

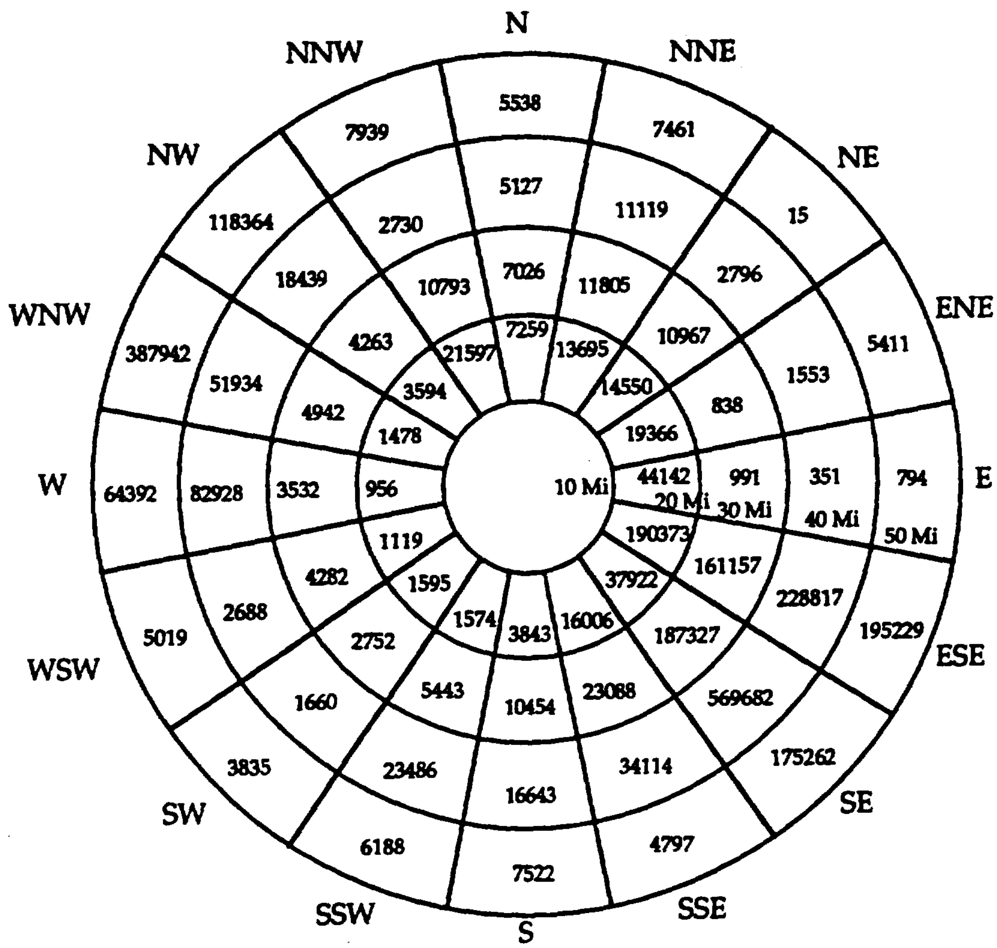


POPULATION BY ANNULUS

ANNULUS	0 TO 10	10 TO 20	20 TO 30	30 TO 40	40 TO 50	TOTAL
POPULATION	139,242	338,472	415,202	9444,420	869,648	2,706,984

S0201012

Figure 2.1-13
50 MILE POPULATION DISTRIBUTION - 2020

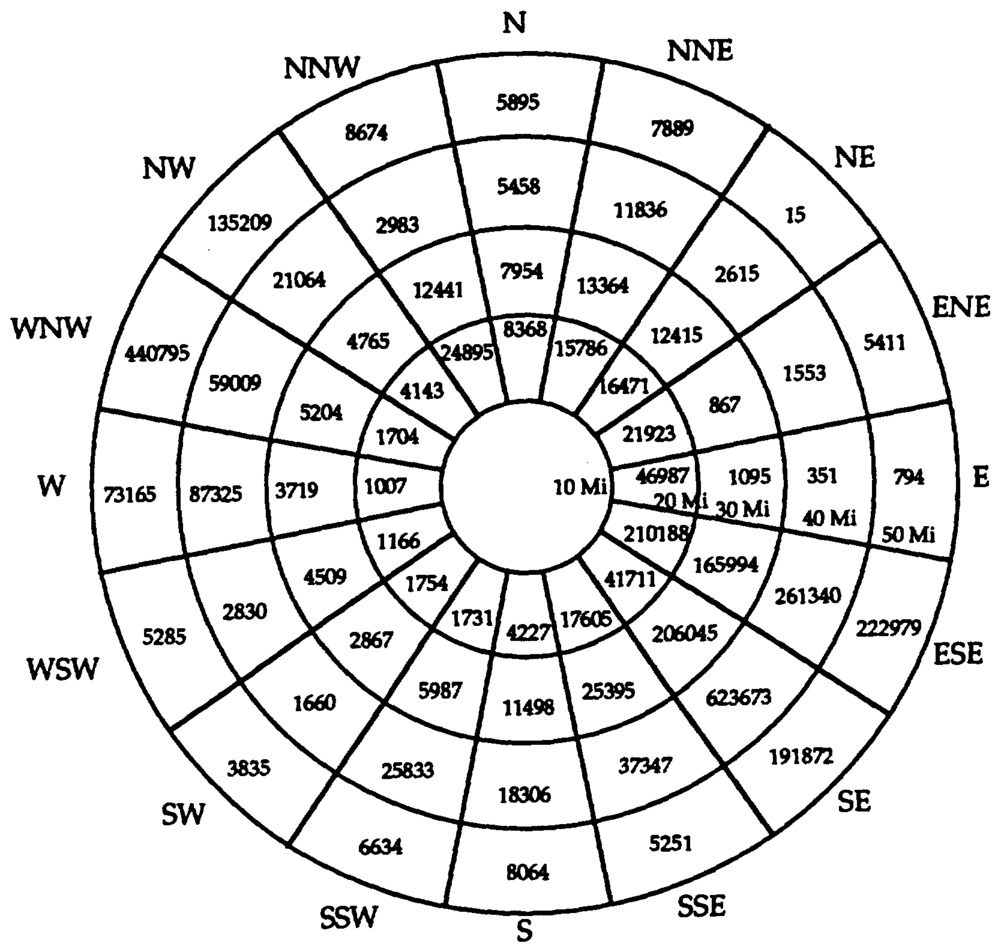


POPULATION BY ANNULUS

ANNULUS	0 TO 10	10 TO 20	20 TO 30	30 TO 40	40 TO 50	TOTAL
POPULATION	157,775	379,069	449,659	1,053,802	995,707	3,036,012

S0201013

Figure 2.1-14
50 MILE POPULATION DISTRIBUTION - 2030



POPULATION BY ANNULUS

ANNULUS	0 TO 10	10 TO 20	20 TO 30	30 TO 40	40 TO 50	TOTAL
POPULATION	176,308	419,666	484,117	1,163,183	1,121,767	3,365,040

S0201014

Figure 2.1-15
POPULATION DENSITY

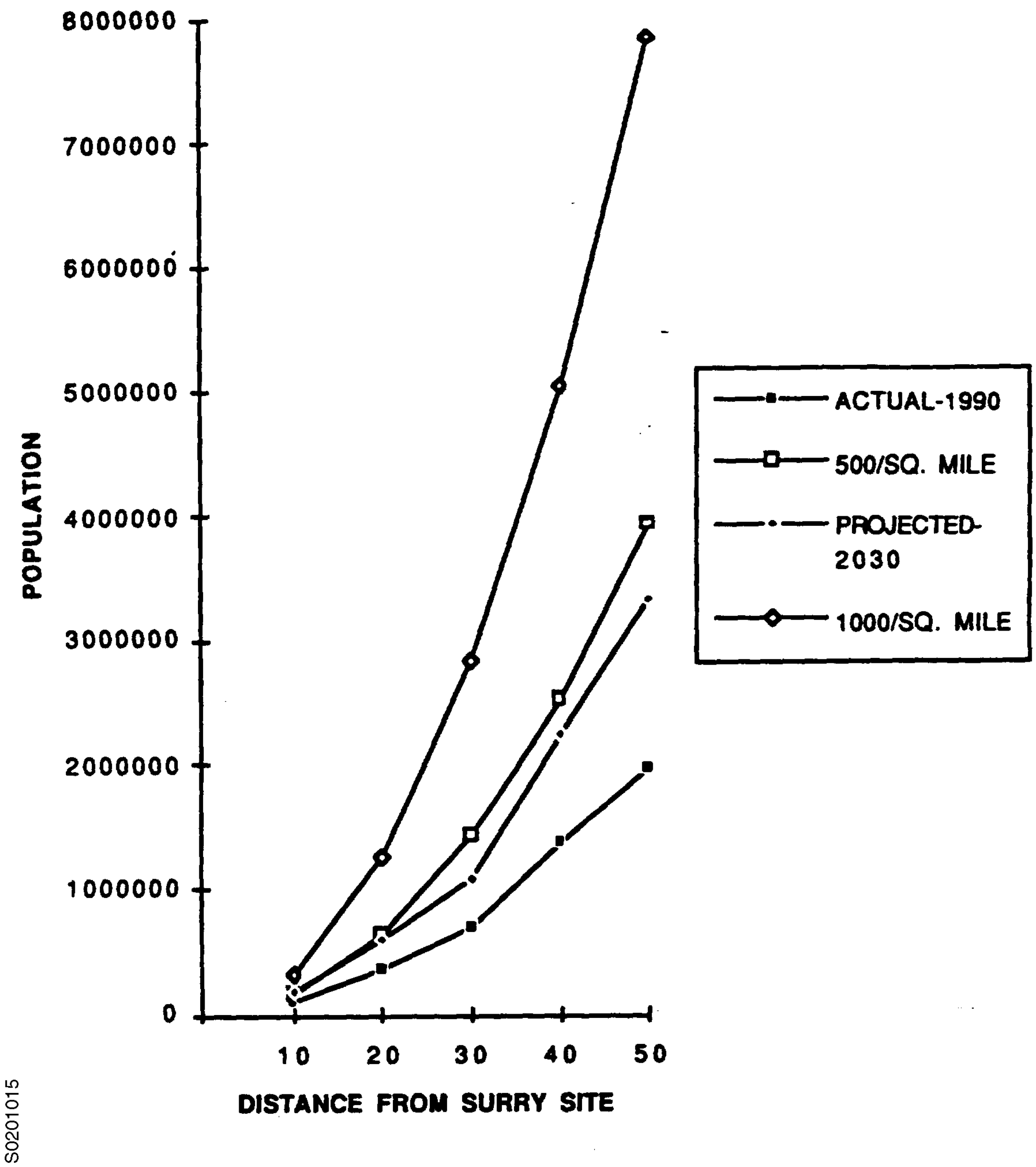


Figure 2.1-16
ADJACENT PIPELINES AND WATERWAYS

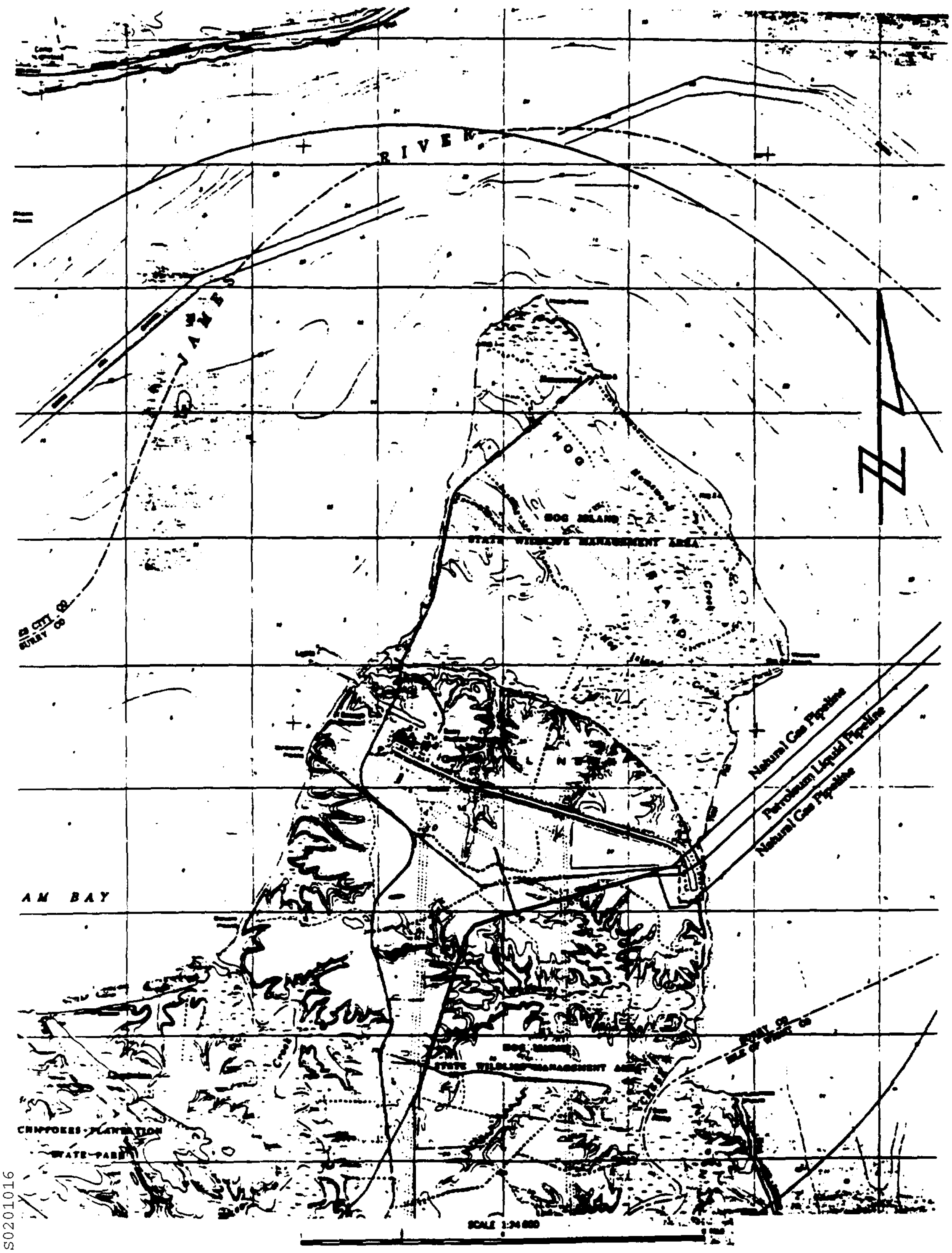
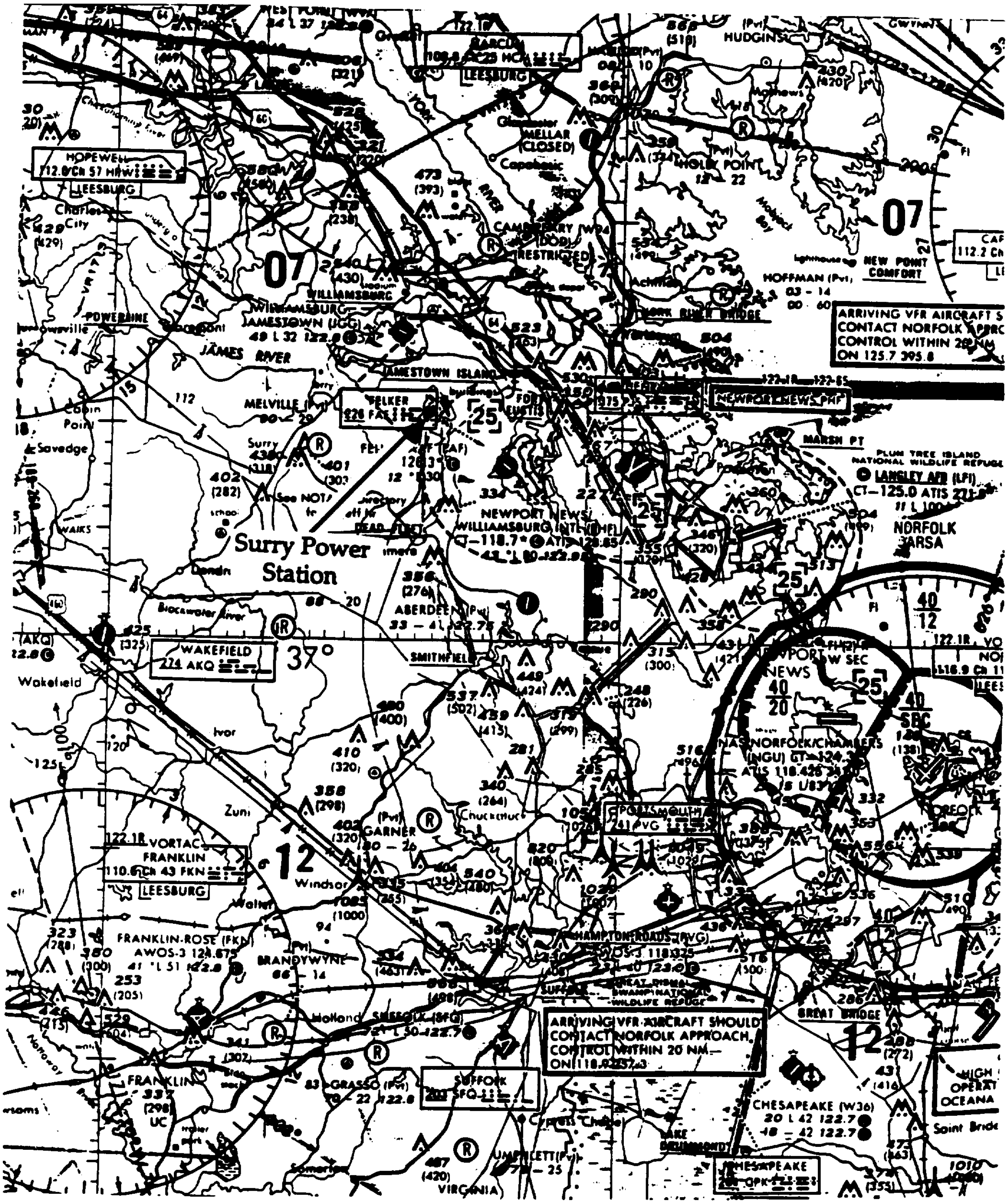


Figure 2.1-17
LOCATION OF AIRPORTS



2.2 METEOROLOGY AND CLIMATOLOGY

2.2.1 Meteorological Program

2.2.1.1 Local Meteorology

Data acquired by the National Weather Service (References 1 through 6) and summarized by the Environmental Data Service have been utilized to determine the normals, means, and extremes of temperature, precipitation, relative humidity, and fog applicable to the Surry Power Station site region. Site data have been obtained from meteorological instrumentation located at the plant site and summarized for the period March 3, 1974, to December 31, 1987.

Climatological data in this report, indicative of both long term expected values and extreme events, have been provided to represent a range of meteorological conditions that are considered typical for the Surry Power Station site region. Through the years it is expectd that some values may change slightly, however, the values presented in this report are stilel considered to be representative of climatic conditions typical to the site region. Climatological extremes for selected meteorological stations in the region are presented in Table 2.2-1. Normals and extremes of temperature, precipitation, relative humidity, and fog are presented for Richmond and Norfolk in Tables 2.2-2, 2.2-3, and 2.2-4. The closest available fog data for Surry site are from the National Weather Service observation stations at Richmond International Airport, Richmond, and Regional Airport, Norfolk, Virginia. The local climatological data (1980) for Richmond indicates an average of 25–30 days per year of heavy fog, and the local climatological data for Norfolk indicates an average of 20–25 days per year of heavy fog. Heavy fog is defined by the National Weather Service as fog which reduces visibility to 0.25 mile or less (Reference 1). The frequency of fog conditions reported at Surry is expected to be more similar to the annual average of heavy fog reported at Richmond than at Norfolk (References 1 & 2). Surry is in close proximity to the James River and has a rural environment (i.e., land-use characteristics favorable for rapid radiation cooling of the ambient air with high specific humidity due to the close proximity of the River). The occurrence of heavy fog in the Norfolk area is less than in the Richmond area due to the moderating influence of the Atlantic Ocean.

The distribution of wind direction and speed is an important consideration when evaluating transport conditions relevant to site diffusion climatology. There are no significant topographic features that would have any major influence on wind direction distribution.

Seasonal and annual distributions of wind direction recorded at the Surry site meteorological tower for both the upper and lower level are presented in Figures 2.2-1 through 2.2-10. On an annual basis the predominant wind direction at both levels is from the southwest and south-southwest direction. Seasonal variations in average wind speed are presented in Table 2.2-5.

Wind persistence is important when considering potential effects from any radiological release. Wind persistence is defined as a continuous flow from a given direction or range of directions. Periods of maximum wind persistence in 22.5 degree sectors recorded at the Surry site meteorological tower are presented in Figures 2.2-11 through 2.2-20. The maximum persistence period at the upper level was for 28 hours, once from the south and once from the north-northeast. At the lower level, the maximum persistence period was 30 hours from the west-southwest.

Atmospheric stability refers to the degree of wind turbulence. Stable conditions are associated with low turbulence and poor diffusion capability. Unstable conditions are associated with a high degree of turbulence and favorable diffusion characteristics. Atmospheric stability is classified into horizontal and vertical stability categories. The degree of wind variance or standard deviation of direction (sigma-theta) is used to determine horizontal stability. The vertical temperature differential (delta T) is used to determine vertical stability. The classification of sigma-theta data is presented in Table 2.2-6 and the classification of delta T data is presented in Table 2.2-7. The seasonal and annual frequency of horizontal (sigma-theta) stability classes and associated wind speeds for the Surry site are presented in Table 2.2-9. These distributions indicate that the wind is more stable at the upper level than at the lower level. Seasonal variations of the stability distribution presented are minor.

Table 2.2-1 lists some extremes of meteorological measurements for selected National Weather Service stations in the Surry region. The maximum amount of precipitation recorded at Norfolk for a 24-hour period was 11.4 inches which occurred in August of 1964. The maximum amount of precipitation recorded at Richmond for a 24-hour period was 8.79 inches during August 1955. The maximum monthly snowfall measured in the Norfolk area was 18.9 inches during February 1980, and the maximum monthly snowfall measured in Richmond was 28.5 inches during January 1940. The maximum 24-hour snowfalls observed were 21.6 inches at Richmond during January of 1940 and 12.4 inches at Norfolk in February 1980 (References 1 & 2). Once again, while these extreme values may change slightly through the years, they are still considered to be representative of extreme conditions typical to the site region.

2.2.1.2 **Onsite Meteorological Measurements Program**

There are two towers installed on the Surry site. Their locations are illustrated on Figure 2.2-21. The primary site monitors wind direction and wind speed at two levels of the tower, ambient air temperature at the lower tower level, differential air temperature between tower levels, horizontal wind direction fluctuation at both tower levels, dewpoint temperature at the lower tower level, and rainfall at the base of the tower. The backup site monitors wind direction, wind speed, and horizontal wind direction fluctuation.

The nearest structures are 500 feet north-northwest and 150 feet northwest of the primary and backup towers, respectively. At the primary site, the nearest continuous tree line is approximately 50 feet south of the tower. Tree heights are 40 to 50 feet. At the backup site, the nearest tree line, with trees 10 to 15-feet high, is located approximately 50 feet south-southwest of the tower.

The primary tower is a guyed, triaxial, open-latticed structure. On May 21, 2012, the primary tower wind and temperature instrument elevations were surveyed. Table 2.2-8 provides the survey and pre-survey above ground level (agl) instrument heights.

The backup tower is a freestanding, triaxial, open-latticed structure. The instrumentation on the backup tower is located at approximately 30.3 feet agl.

On the primary tower, the wind speed, wind direction, and sigma-theta sensors are mounted on booms longer than one-and-one-half times the tower face width. On the backup tower, the sensors are postmounted on top of the tower. The wind sensors are positioned such that the towers do not influence the prevailing south-southwest wind flow detected by the sensors. Temperature, differential temperature, and dewpoint temperature sensors are housed in motor-aspirated shields to insulate them from thermal radiation from the tower, solar, and terrestrial radiation.

Meteorological monitoring instrumentation is calibrated not less than semiannually. Inspection, service, and maintenance are performed as required to ensure adequate data recovery. Redundant recording systems are incorporated into the program to minimize data loss due to recorder failure. The data are listed, reviewed, and summarized into joint frequency distributions by using the atmospheric stability classification scheme shown in Table 1 of Regulatory Guide 1.23 (Proposed Revision 1).

Data from the site's primary and backup meteorological towers are transmitted to the control room and collected by the emergency response facility data acquisition system (ERFDAS). These parameters have been placed in the ERFDAS data base, thus making site meteorological field data available for display in the Technical Support Center (TSC), and the Corporate Emergency Response Center (CERC). Certain information is also hardwired for display on the control room meteorological panels. Table 2.2-10 identifies meteorological information transmitted and its display location. Additional information on emergency response facilities can be found in the Station Emergency Plan.

Temperature, differential temperature, wind speed, and wind direction from both the lower and upper primary tower level sensors are displayed on recorders in the control room, as are wind speed, wind direction, and sigma-theta from the backup tower.

A shelter is located at the base of each tower. The shelters have thermostatically-controlled heat and air conditioning to maintain an interior temperature within a range appropriate for proper equipment operation. The enclosures are located to minimize any micrometeorological effects on the tower instrumentation.

Inside the shelters, the signals are routed to the appropriate signal-conditioning equipment which go to (1) digital data recorders and (2) an interface with the intelligent remote multiplexer system.

Microprocessor-based data acquisition systems are the primary method of data collection for offsite historical files. In addition to being transmitted real-time to the control room recorders and to the ERFDAS, the data from the primary data collection system are telemetered daily to a computer in the corporate office. The data are then reviewed for representativeness and reasonability, including a comparison with data from other Company meteorological tower sites. Monthly, the data are transferred to the corporate mainframe computer for inclusion in the historical database. Backup collection consists of several remote data acquisition systems.

Meteorological instrumentation and data recording described above was upgraded to be consistent with Regulatory Guide 1.23, Onsite Meteorological Programs, Proposed Revision 1, and Regulatory Guide 1.97, Revision 3, Instrumentation for Light-water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, May 1983.

The meteorological sites and towers are consistent with Regulatory Guide 1.23, Onsite Meteorological Programs, February 1972.

2.2.2 Climate

Data acquired by the National Weather Service (NWS) and summarized by the Environmental Data Service (EDS) were used to determine the regional climatology pertinent to the Surry site. References 1 and 2 were used to determine the climatological characteristics of Richmond and Norfolk, Virginia, and Reference 7 for the climatological characteristics of the region.

The Surry site is situated in a humid subtropical climate which is characterized by warm, humid summers and mild winters. During the summer months, this region is dominated by tropical maritime air masses, while during the winter season this area is in a transitional zone between polar continental and tropical maritime air masses.

The climatic characteristics of the site region are influenced by the Atlantic Ocean, the Chesapeake Bay, and the Appalachian Mountains. The Atlantic Ocean has a moderating effect on the temperature for the Surry region, whereas the Appalachians act as a barrier to deflect midwest winter storms to the northeast of the Surry region. Winters are mild and short, spring and fall weather is usually very comfortable, and summers are long, hot, and humid, frequently tempered by cool periods associated with east and northeast winds off the Atlantic Ocean.

Snow is not common during winter in the Tidewater area of Virginia. (The Tidewater area is defined as the Coastal Plain area of Virginia extending west to the Fall Line.) A snowfall of 10 inches or more a month in the Tidewater area is expected to occur once every 4 years. In general, the total accumulated snow for the Tidewater is approximately 10 inches each year. Precipitation occurs mostly as rain in the site area. The summer months are usually associated with the greatest amount of precipitation. However, great amounts of rainfall have occurred during the fall season associated with the passages of tropical storms or hurricanes.

The Bermuda high that develops off the coast of the United States during the spring and summer seasons results in a moist, southerly flow of air from the Caribbean and South Atlantic to the Surry region. During the fall and winter seasons, a semipermanent high-pressure cell develops over the midwest region of the United States, resulting in a prevailing northwesterly flow of air into the Surry region. The mean annual wind speed for the Norfolk area is approximately 11 mph, and the mean annual wind speed for Richmond is approximately 8 mph.

Thunderstorms are frequent during the summer months with the greatest occurrence during the month of July. Only a small percentage of the thunderstorms can be classified as severe. Approximately four tornados are reported in Virginia each year, with the majority occurring east of the Blue Ridge Mountains.

An average of less than two hurricanes each year comes close enough to the coast to affect Virginia. These hurricanes can bring torrential rainfall to the Tidewater area, and high tides that result in flood conditions for low-lying areas along the coast. However, less than one hurricane per year actually crosses the state. A typical hurricane to affect the Tidewater area was Hurricane Dennis (August 1981), which brought 2.4 inches of rainfall to the Norfolk area and 0.25 inch to the Richmond area.

2.2.2.1 **Tornadoes**

During the period of January 1951 through December 1987, a total of 49 tornadoes on land have been reported within a 50-mile radius of the Surry site for an average of 1.3 tornadoes per year within this radius. As additional years of data are included in the analyses, it is expected that averages may change slightly. However, the averages presented in this report are still considered to be appropriate estimates of conditions typical to the site region.

The probability of a tornado striking a point within a given area may be estimated as follows (Reference 8):

$$P = \frac{zt}{A}$$

Where:

P = the mean probability per year

z = the geometric mean tornado path area

t = the mean number of tornadoes per year observed in the area of concern A

For the region surrounding the Surry site, the computed geometric mean tornado path length was about 1.6 miles and the computed geometric mean path width reported was about 118 yards, based on examination of reported tornado statistics (Reference 9). These values yield a z of 0.106 square miles based on tornado data for the period of January 1951 through December 1987. Using a 50-mile radius as a basis for A (excluding the Chesapeake Bay) and a value of

1.3 tornadoes per year for t, yields a probability of 1.73×10^{-5} per year, or a recurrence interval of about 58,000 years.

The Class 1 structures and systems, or parts thereof, whose failure might prevent the simultaneous cold shutdown of both reactor units during a loss-of-power incident will withstand by design a tornado with the following characteristics and associated effects:

1. Rotational wind velocity of 300 mph.
2. A pressure drop of 3 psi in 3 seconds.
3. Translational velocity of 60 mph.
4. Missile equivalent to a wooden utility pole 40-foot long, with 12-inch diameter, weighing 50 lb/ft^3, and traveling in a vertical or horizontal direction at 150 mph.
5. Missile equivalent to a 1-ton automobile traveling at 150 mph.

The pressure change and translational velocity above have been adopted from the license applications of others. The pressure change of 3.0 psi is considered conservative. The greatest officially observed pressure change near a tornado was 0.34 psi (which occurred in a 2-minute period) recorded at the Topeka Airport on June 8, 1966, as reported by Galway (Reference 10). The published work of Brooks (Reference 11) and Glaser (Reference 12) suggests that wind velocities of 220 to 300 mph would be produced by a central pressure difference of 1.1 to 1.5 psi.

Before adopting the tornado characteristics above, a tornado model was prepared to develop pressure and wind velocity criteria that were physically consistent. This tornado model was similar to the one suggested by Hoecker (Reference 13). The model included the following tornado specifications:

1. Overall diameter, 1000 ft.
2. Central pressure, 13.0 psia.
3. Central pressure difference, 1.5 psi.
4. Maximum pressure gradient, 0.02 psi/ft.
5. Radius of maximum winds, 200 ft.

Using this pressure structure and the cyclostrophic wind equation, an estimate of the maximum winds that would occur within such a tornado was obtained as follows (Reference 14):

$$V^2 = \frac{rg}{\rho}\ \frac{p}{r}$$

where:

p/ r = maximum pressure gradient, 2.88 $lb/ft^2/ft$ (0.02 psi/ft)

r = radius of maximum wind, 200 ft

ρ = density of air, 0.075 lb/ft^3

g = 32.2 ft/sec^2

V = maximum wind velocity, fps

The calculated maximum wind velocity of 338 mph compares with the design wind velocity of 300 mph, which is based on observed structural damage. Thus, the modeled tornado pressure distribution with a central pressure difference of 1.5 psi and a maximum pressure gradient of 0.02 psi/ft is physically consistent with accepted estimates of wind speeds associated with tornadoes. The model and derived estimates are also in agreement with the published works of Brooks, Glaser, and Hoecker. While the pressure difference of 1.5 psi is consistent with the other tornado characteristics chosen, the more conservative pressure difference of 3.0 psi has been used.

2.2.2.2 **Extreme Winds**

Extreme wind data were obtained from studies by Thom (Reference 15) and Huss (Reference 16). Severe weather data were obtained from a variety of sources. Severe storm, tornado, and hurricane data were obtained from References 8, 9, 17, 18 and 19.

According to Thom, the extreme 1-mile wind speed at 30 feet above the ground for a 100-year recurrence interval for the Surry region is 105 mph. Based on a gustiness factor of 1.3 according to Huss, the highest instantaneous gust expected once in 100 years is 137 mph.

The fastest mile wind recorded at Norfolk based on the 1953 to 1987 period of record was a southerly wind with a speed of 78 mph (Reference 2). The fastest mile wind recorded at Richmond based on the 1951 to 1987 period of record was a southeasterly wind with a speed of 68 mph (Reference 1). Both of these extreme wind speeds occurred during the passage of Hurricane Hazel in October 1954. While greater extreme wind speeds may occur in the future, these values are considered to be representative of extreme conditions typical to the site region.

2.2.2.3 **Tropical Storms and Hurricanes**

Since 1871 (when more complete weather recordkeeping began) through 1987, a total of 56 tropical storms or hurricane centers passed within 100 nautical miles of the Surry site (References 9 & 18). After 1885, weather records differentiated between tropical storms (less that 73 mph) and hurricanes (greater than 73 mph). From 1886 through 1987, there have been 34 passages of tropical storms, and 10 hurricanes have passed within 100 nautical miles of the site.

2.2 REFERENCES

1. National Oceanic and Atmospheric Administration, *Richmond, Virginia, 1987, Local Climatological Data, Annual Summary with Comparative Data*, Environmental Data Services, Asheville, North Carolina.
2. National Oceanic and Atmospheric Administration, *Norfolk, Virginia, 1987, Local Climatological Data, Annual Summary with Comparative Data*, Environmental Data Service, Asheville, North Carolina.
3. National Oceanic and Atmospheric Administration, *Climatological Data, Virginia, Annual Summary, 1987*, Environmental Data Service, Asheville, North Carolina, 1988.
4. C. W. Crockett, *Climatological Summaries for Selected Stations in Virginia - Holland*, Water Resources Research Center, Virginia Polytechnic Institute and State University, “53,” Blacksburg, Virginia, 1972.
5. C. W. Crockett, *Climatological Summaries for Selected Stations in Virginia - Hopewell*, Water Resources Research Center, Virginia Polytechnic Institute and State University, “53,” Blacksburg, Virginia, 1972.
6. C. W. Crockett, *Climatological Summaries for Selected Stations in Virginia - Williamsburg*, Water Resources Research Center, Virginia Polytechnic Institute and State University, “53,” Blacksburg, Virginia, 1972.
7. U.S. Department of Commerce, *Climates of the States, Climate of Virginia, Climatography of the United States No. 60-44*, Washington, D.C., 1981.
8. H. C. S. Thom, “Tornado Probabilities,” *Monthly Weather Review 91*, pp. 730-736 (1963).
9. National Oceanic and Atmospheric Administration, *Storm Data*, National Weather Records Center, Environmental Data Service, Asheville, North Carolina.
10. J. C. Galway, “The Topeka Tornado of June 8, 1966,” *Weatherwise*, Vol. 19, No. 4, August 1966.
11. *E. M. Brooks, Tornadoes and Related Phenomena, Compendium of Meteorology*, American Meteorological Society, Waverly Press, Inc., Baltimore, Maryland, 1951.
12. A. H. Glaser, *Tornado Studies*, Final Report, Texas A & M, January 1956.
13. W. H. Hoecker, “Three-Dimensional Pressure Pattern of the Dallas Tornado and Some Resultant Implications,” *Monthly Weather Review*, December 1961.
14. R. E. Huschke, *Glossary of Meteorology*, American Meteorological Society, Boston, Massachusetts, 1959, p. 151.
15. H. C. S. Thom, *New Distribution of Extreme Mile Winds in the United States*, ASCE Environmental Engineering Conference, Dallas, Texas, February 1967.

16. P. O. Huss, *Relation Between Gusts and Average Wind Speed*, Report 140, David Guggenheim Airship Institute, Report 140, Cleveland, Ohio, 1946.

17. *Climatological Data - National Summary*, U.S. Department of Commerce, Weather Bureau, 1951-1958.

18. C. W. Cry, "Tropical Cyclones of the North Atlantic Ocean," *Technical Paper No. 55*, National Oceanic and Atmospheric Administration, Washington, D.C., 1965.

19. National Oceanic and Atmospheric Administration, *Climatological Data, Virginia*, Environmental Data Service, Asheville, North Carolina, June 1982.

Table 2.2-1
SELECTED NATIONAL WEATHER SERVICE STATIONS FOR METEOROLOGICAL EXTREMES IN THE SURRY SITE REGION (DATE OF OCCURRENCE)

	Norfolk		Richmond	
Maximum temperature, °F	104	(8/80)	105	(7/77)
Minimum temperature, °F	-3	(1/85)	-12	(1/40)
Maximum monthly rainfall, in.	13.8	(9/79)	18.87	(7/45)
Maximum monthly snowfall, in.	18.9	(2/80)	28.5	(1/40)
Maximum 24-hr rainfall, in.	11.4	(8/64)	8.79	(8/55)
Maximum 24-hr snowfall, in.	12.4	(2/80)	21.6	(1/40)
Fastest mile wind, mph	78 S	(10/54)	68 SE	(10/54)

Table 2.2-2
NORMALS, MEANS, AND EXTREMES - RICHMOND, VIRGINIA

LATITUDE: 37°30'N LONGITUDE: 77°20'W ELEVATION: FT GRND 164 BARO 178 TIME ZONE: EASTERN WBAN: 13740

	(a)	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F:														
Normals														
-Daily Maximum		46.7	49.6	58.5	70.6	77.9	84.8	88.4	87.1	81.0	70.5	60.5	50.2	68.8
-Daily Minimum		26.5	28.1	35.8	45.[illegible]	54.2	62.2	67.2	66.4	59.3	46.7	37.3	29.6	46.5
-Monthly		36.6	38.9	47.2	57.9	66.[illegible]	73.5	77.8	76.8	70.2	58.6	48.9	39.9	57.7
Extremes														
-Record Highest	55	[illegible]	83	93	96	100	104	105	[illegible]	103	99	[illegible]	[illegible]	105
-Year		1950	1932	1938	1985	1941	1952	1977	1983	1954	1941	1974	[illegible]	JUL 1977
-Record Lowest	58	-12	-10	[illegible]	23	[illegible]	[illegible]	[illegible]	46	35	[illegible]	[illegible]	[illegible]	-12
-Year		1940	1936	1960	1985	1956	1967	1965	1934	1974	1962	1933	[illegible]	JAN 1940
NORMAL DEGREE DAYS:														
Heating (base 65°F)		880	[illegible]	552	226	65	[illegible]	[illegible]	0	24	221	483	[illegible]	3960
Cooling (base 65°F)		0	0	0	[illegible]	99	[illegible]	[illegible]	366	180	23	[illegible]	[illegible]	1336
% OF POSSIBLE SUNSHINE	[illegible]	54	58	[illegible]	65	65	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	56	53	62
MEAN SKY COVER (tenths)														
Sunrise - Sunset	42	6.4	6.2	6.2	[illegible]	6.3	6.0	[illegible]	6.0	5.6	5.4	5.9	6.2	6.0
MEAN NUMBER OF DAYS:														
Sunrise to Sunset														
-Clear	42	8.4	8.4	8.3	8.0	[illegible]	[illegible]	[illegible]	[illegible]	9.4	[illegible]	9.5	9.6	[illegible]
-Partly Cloudy	42	[illegible]	6.3	8.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8.6	7.2	7.6	6.3	105.5
-Cloudy	42	15.9	13.5	14.5	12.8	13.8	11.4	12.5	11.9	12.0	12.3	12.9	[illegible]	158.6
Precipitation														
.01 inches or more	50	10.3	[illegible]	10.6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	7.9	[illegible]	8.3	[illegible]	[illegible]
Snow, Ice pellets														
1.0 inches or more	50	[illegible]	[illegible]	0.6	[illegible]	0.0	0.0	0.0	0.0	0.0	0.0	[illegible]	[illegible]	[illegible]
Thunderstorms	50	0.2	0.4	[illegible]	2.5	5.5	[illegible]	[illegible]	[illegible]	3.0	[illegible]	0.5	0.3	[illegible]
Heavy Fog Visibility 1/4 mile or less	56	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3.3	2.4	2.8	[illegible]
Temperature °F														
-Maximum														
90° and above	58	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	9.4	[illegible]	[illegible]	4.5	0.4	[illegible]	[illegible]	[illegible]
32° and below	58	3.3	[illegible]	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	[illegible]	[illegible]	[illegible]
-Minimum														
32° and below	58	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0° and below	58	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AVG. STATION PRESS (mb)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
RELATIVE HUMIDITY (%)														
Hour [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Hour [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Hour [illegible] (Local Time)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Hour [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PRECIPITATION (inches):														
Water Equivalent														
-Normal		3.23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3.52	3.74	3.29	3.39	44.07
-Maximum Monthly	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	10.98	[illegible]	[illegible]	[illegible]	[illegible]
-Year		1978	1979	1984	[illegible]	[illegible]	[illegible]	[illegible]	1955	1975	[illegible]	1959	[illegible]	JUL 1945
-Minimum Monthly	[illegible]	0.64	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.26	[illegible]	[illegible]	[illegible]	[illegible]
-Year		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1965	[illegible]	SEP 1978
-Maximum in 24 hrs	50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
-Year		[illegible]	[illegible]	1984	[illegible]	[illegible]	[illegible]	[illegible]	1955	[illegible]	[illegible]	[illegible]	1958	AUG 1955
Snow, Ice pellets														
-Maximum Monthly	50	[illegible]	[illegible]	[illegible]	[illegible]						[illegible]	[illegible]	[illegible]	[illegible]
-Year		[illegible]	[illegible]	[illegible]	[illegible]						[illegible]	[illegible]	1958	JAN [illegible]
-Maximum in 24 hrs	50	[illegible]	[illegible]	[illegible]	[illegible]						[illegible]	[illegible]	[illegible]	[illegible]
-Year		[illegible]	[illegible]	[illegible]	[illegible]						[illegible]	[illegible]	[illegible]	JAN [illegible]
WIND:														
Mean Speed (mph)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Prevailing Direction through [illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Fastest Mile														
-Direction	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
-Speed (MPH)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
-Year		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	OCT [illegible]
Peak Gust														
-Direction	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
-Speed (mph)		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
-Date		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1985	JUL 1986

S0202022

Table 2.2-2 (CONTINUED)
NORMALS, MEANS, AND EXTREMES - RICHMOND, VIRGINIA

REFERENCE NOTES

GENERAL
T - TRACE AMOUNT
BLANK ENTRIES DENOTE MISSING/UNREPORTED DATA
# INDICATES A STATION OR INSTRUMENT RELOCATION
SEE STATION LOCATION TABLE ON PAGE 8

SPECIFIC
PAGE 2
PM - INCLUDES LAST DAY OF PREVIOUS MONTH

PAGE 3
(a) - LENGTH OF RECORD IN YEARS, ALTHOUGH
INDIVIDUAL MONTHS MAY BE MISSING
* LESS THAN .05
NORMALS - BASED ON THE 1951-1980 RECORD PERIOD
EXTREMES - DATES ARE THE MOST RECENT OCCURRENCE
WIND DIR - NUMERALS SHOW TENS OF DEGRESS CLOCKWISE
FROM TRUE NORTH. 00 INDICATES CALM
RESULTANT DIRECTIONS ARE GIVEN TO WHOLE DEGREES

PAGE 4B
MAX AND MIN ARE LONG TERM MEAN DAILY MAXIMUM
AND MEAN DAILY MINIMUM TEMPERATURES

EXCEPTIONS

PAGES 4A, 4B, 6A
RECORD MEANS ARE THROUGH THE CURRENT YEAR,
BEGINNING IN 1930 FOR TEMPERATURE
1930 FOR PRECIPITATION
1938 FOR SNOWFALL

S0202023

Table 2.2-3
NORMALS, MEANS, AND EXTREMES - NORFOLK, VIRGINIA

LATITUDE: 36°54'N LONGITUDE: 76°12'W ELEVATION: FT GRND 24 BARO 34 TIME ZONE: EASTERN WBAN: 13737

	(a)	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F:														
Normals														
-Daily Maximum		48.1	49.9	57.5	68.2	75.7	83.2	86.9	85.7	80.2	69.8	60.8	51.9	68.2
-Daily Minimum		31.7	32.3	39.4	48.1	57.2	65.3	69.9	69.6	64.2	52.8	43.0	35.0	50.7
-Monthly		39.9	41.1	48.5	58.2	66.4	74.3	78.4	77.7	72.2	61.3	51.9	43.5	59.5
Extremes														
-Record Highest	39	78	81	88	97	97	101	103	104	99	95	86	80	104
-Year		1970	1976	1985	1960	1956	1964	1952	1980	1983	1954	1974	1978	AUG 1980
-Record Lowest	39	-3	5	18	28	36	45	54	49	45	27	20	7	-3
-Year		1985	1965	1980	1982	1966	1967	1979	1982	1967	1976	1950	1983	JAN 1985
NORMAL DEGREE DAYS:														
Heating (base 65°F)		778	669	512	219	53	0	0	0	9	146	393	667	3446
Cooling (base 65°F)		0	0	0	15	96	282	415	394	225	31	0	0	1458
% OF POSSIBLE SUNSHINE	33	56	58	62	64	64	67	64	64	63	59	57	57	61
MEAN SKY COVER (tenths)														
Sunrise - Sunset	39	6.2	6.2	6.0	5.8	6.1	5.8	6.0	5.9	5.7	5.5	5.5	6.0	5.9
MEAN NUMBER OF DAYS:														
Sunrise to Sunset														
-Clear	39	9.2	8.2	9.1	9.0	8.1	7.6	7.7	8.1	9.2	11.6	10.5	9.3	107.5
-Partly Cloudy	39	6.5	6.2	7.4	9.0	9.7	11.6	11.6	12.0	9.4	7.0	7.8	7.2	105.5
-Cloudy	39	15.4	13.8	14.5	12.0	13.3	10.8	11.6	10.9	11.4	12.4	11.6	14.5	152.2
Precipitation														
.01 inches or more	39	10.4	10.2	10.8	9.9	9.8	9.0	11.2	10.4	7.8	7.6	8.1	9.2	114.3
Snow, Ice pellets														
1.0 inches or more	39	0.8	0.7	0.3	0.*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.1
Thunderstorms	39	0.4	0.6	1.8	2.7	4.8	5.7	8.4	7.1	2.7	1.4	0.5	0.4	36.5
Heavy Fog Visibility														
1/4 mile or less	39	2.1	2.8	1.9	1.5	2.0	1.2	0.6	1.1	1.3	2.3	2.0	2.2	20.8
Temperature °F														
-Maximum														
90° and above	39	0.0	0.0	0.0	0.5	1.5	6.4	11.5	8.7	2.9	0.1	0.0	0.0	31.6
32° and below	39	2.8	1.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	5.1
-Minimum														
32° and below	39	[illegible]	14.5	6.2	0.3	0.0	0.0	0.0	0.0	0.0	0.2	3.2	13.4	54.8
0° and below	39	0.*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*
AVG. STATION PRESS. (mb)	15	1017.7	1017.8	1016.1	1014.9	1014.8	1015.2	1015.7	1016.9	1017.5	1018.9	1019.0	1019.0	1017.0
RELATIVE HUMIDITY (%)														
Hour 01	39	[illegible]	[illegible]	[illegible]	[illegible]	80	83	84	86	84	82	76	73	78
Hour 07 (Local Time)	39	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	84	83	83	79	75	78
Hour 13	39	[illegible]	[illegible]	[illegible]	53	56	56	[illegible]	[illegible]	[illegible]	[illegible]	56	58	57
Hour 19	39	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	68	68
PRECIPITATION (inches):														
Water Equivalent														
-Normal		3.72	3.28	3.86	2.87	3.75	3.45	5.15	5.33	4.35	3.41	2.88	3.17	45.22
-Maximum Monthly	39	[illegible]	6.23	7.80	[illegible]	10.12	[illegible]	13.73	[illegible]	13.80	10.12	7.01	6.10	13.80
-Year		[illegible]	1983	1978	1984	1979	1963	1975	1967	1979	1971	1951	1983	SEP 1979
-Minimum Monthly	39	[illegible]	0.66	0.75	0.43	1.41	[illegible]	[illegible]	0.74	0.26	0.57	0.49	0.79	0.26
-Year		1981	1950	1986	1985	1986	1954	1983	1975	1986	1984	1965	1985	SEP 1986
-Maximum in 24 hrs	39	3.80	[illegible]	3.18	2.93	3.41	6.85	5.64	11.40	6.79	4.38	3.35	2.76	11.40
-Year		[illegible]	1983	1958	1984	1980	1963	1969	1964	1959	1971	1952	1983	AUG 1964
Snow, Ice pellets														
-Maximum Monthly	39	14.2	18.9	[illegible]	[illegible]							0.6	14.7	18.9
-Year		1966	1980	1980	1964							1950	1958	FEB 1980
-Maximum in 24 hrs	39	[illegible]	12.4	[illegible]	[illegible]							0.6	11.4	12.4
-Year		[illegible]	1980	[illegible]	1964							1950	1958	FEB 1980
WIND:														
Mean Speed (mph)	39	[illegible]	[illegible]	12.5	[illegible]	10.4	[illegible]	8.9	8.9	9.6	10.4	10.6	11.1	10.6
Prevailing Direction through 1963		SW	NNE	SW	SW	SW	SW	SW	SW	NE	NE	SW	SW	SW
Fastest Obs. 1 Min.														
-Direction		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	34	[illegible]	[illegible]	04	10	26	04
-Speed (MPH)		[illegible]	44	46	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	46	[illegible]	39	[illegible]	48
-Year		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1985	1982	1985	1985	OCT 1982
Peak Gust														
-Direction		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	NE	[illegible]	[illegible]	SW
-Speed (mph)		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	46	55	53	69
-Date		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1985	1966	1985	1985	JUN 1987

S0202024

Table 2.2-3 (CONTINUED)
NORMALS, MEANS, AND EXTREMES - NORFOLK, VIRGINIA

REFERENCE NOTES

GENERAL
T - TRACE AMOUNT
BLANK ENTRIES DENOTE MISSING/UNREPORTED DATA
* INDICATES A STATION OR INSTRUMENT RELOCATION
SEE STATION LOCATION TABLE ON PAGE 8

SPECIFIC
PAGE 2
PM - INCLUDES LAST DAY OF PREVIOUS MONTH

PAGE 3
(a) - LENGTH OF RECORD IN YEARS, ALTHOUGH
INDIVIDUAL MONTHS MAY BE MISSING.
* LESS THAN .05
NORMALS - BASED ON THE 1951-1980 RECORD PERIOD
EXTREMES - DATES ARE THE MOST RECENT OCCURRENCE
WIND DIR - NUMERALS SHOW TENS OF DEGRESS CLOCKWISE
FROM TRUE NORTH. "00" INDICATES CALM
RESULTANT DIRECTIONS ARE GIVEN TO WHOLE DEGREES.

PAGE 4B
MAX AND MIN ARE LONG TERM MEAN DAILY MAXIMUM
AND MEAN DAILY MINIMUM TEMPERATURES

EXCEPTIONS

PAGE 3
' PERCENT OF POSSIBLE SUNSHINE IS THROUGH 1980.
PAGES 4A, 4B, 6A
RECORD MEANS ARE THROUGH THE CURRENT YEAR,
BEGINNING IN 1875 FOR TEMPERATURE
1871 FOR PRECIPITATION
1949 FOR SNOWFALL

S0202025

Table 2.2-4
MONTHLY METEOROLOGICAL MEANS FOR TEMPERATURE AND PRECIPITATION FOR STATIONS IN THE SURRY SITE REGION

Month	Norfolk	Richmond
January		
Temp, °F	39.9	36.6
Precipitation, in.	3.72	3.23
February		
Temp, °F	41.1	38.9
Precipitation, in.	3.28	3.13
March		
Temp, °F	48.5	47.2
Precipitation, in.	3.86	3.57
April		
Temp, °F	58.2	57.8
Precipitation, in.	2.87	2.90
May		
Temp, °F	66.4	66.1
Precipitation, in	3.75	3.55
June		
Temp, °F	74.3	73.5
Precipitation, in.	3.45	3.60
July		
Temp, °F	78.4	77.8
Precipitation, in.	5.15	5.14
August		
Temp, °F	77.7	76.8
Precipitation, in.	5.33	5.01
September		
Temp, °F	72.2	70.2
Precipitation, in.	4.35	3.52
October		
Temp, °F	61.3	58.6
Precipitation, in.	3.41	3.74
November		
Temp, °F	51.9	48.9
Precipitation, in.	2.88	3.29
December		
Temp, °F	43.5	39.9
Precipitation, in.	3.17	3.39
Annual		
Temp, °F	59.5	57.7
Precipitation, in.	45.22	44.07

Table 2.2-5
SURRY SEASONAL AND ANNUAL MEAN WIND SPEED SUMMARY (MPH)
1974 - 1987

	Upper Level	Lower Level
Spring (March, April, May)	10.6	6.3
Summer (June, July, August)	8.8	4.9
Fall (September, October, November)	9.4	5.1
Winter (December, January, February)	10.3	6.0
Annual	9.7	5.6

Table 2.2-6
HORIZONTAL (σ_θ) STABILITY CATEGORIES

Stability Category	Range of Standard Deviation (degrees)	Atmospheric Turbulence
A - extremely unstable	$\sigma_\theta \geq 22.5$	High
B - unstable	$22.5 > \sigma_\theta \geq 17.5$	High
C - slightly unstable	$17.5 > \sigma_\theta \geq 12.5$	High
D - neutral	$12.5 > \sigma_\theta \geq 7.5$	Moderate
E - slightly stable	$7.5 > \sigma_\theta \geq 3.8$	Low
F - stable	$3.8 > \sigma_\theta \geq 2.1$	Low
G - extremely stable	$2.1 > \sigma_\theta$	Low

Table 2.2-7
VERTICAL (ΔT) STABILITY CATEGORIES

Stability Category	Range of Vertical Temperature Gradient (°C/100 m)	Range of Vertical Temperature Gradient (°F/1000 ft)	Atmospheric Turbulence
A - very unstable	$\Delta T < -1.9$	$\Delta T < -10.4$	High
B - moderately unstable	$-1.9 \leq \Delta T < -1.7$	$-10.4 \leq \Delta T < -9.3$	High
C - slightly unstable	$-1.7 \leq \Delta T < -1.5$	$-9.3 \leq \Delta T < -8.2$	High
D - neutral	$-1.5 \leq \Delta T < -0.5$	$-8.2 \leq \Delta T < -2.7$	Moderate
E - slightly stable	$-0.5 \leq \Delta T < 1.5$	$-2.7 \leq \Delta T < 8.2$	Low
F - moderately stable	$1.5 \leq \Delta T < 4.0$	$8.2 \leq \Delta T < 22.0$	Low
G - very stable	$4.0 \leq \Delta T$	$22.0 \leq \Delta T$	Low

Table 2.2-8
PRIMARY MET TOWER INSTRUMENT HEIGHTS (AGL)*

Level	Instrument	Pre-Survey	Survey**
Upper	Wind	150.0 ft	151.2 ft
	Temperature	147.4 ft	149.4 ft
Lower	Temperature	31.5 ft	35.4 ft
	Wind	34.0 ft	34.7 ft
	Dew Point	31.5 ft	N/S

*(agl) above ground level
**Primary tower wind and temperature instruments surveyed 05/21/2012 but dew point not surveyed N/S

Table 2.2-9
SURRY SEASONAL AND ANNUAL STABILITY AND WIND SPEED DISTRIBUTION
1974 - 1987

	A	B	C	D	E	F	G
Spring (Mar, Apr, May)							
Upper frequency, %	3.97	4.22	13.55	44.68	26.61	5.11	1.87
Wind Speed, mph	(5.4)	(6.8)	(9.0)	(11.5)	(10.3)	(8.6)	(7.9)
Lower frequency, %	5.55	18.89	36.03	31.60	6.52	1.02	0.39
Wind Speed, mph	(7.8)	(10.4)	(10.7)	(11.1)	(7.9)	(5.6)	(6.6)
Summer (June, July, Aug)							
Upper frequency, %	5.46	5.65	14.86	37.26	27.22	6.81	3.11
Wind Speed, mph	(5.0)	(6.1)	(7.6)	(9.3)	(8.7)	(7.7)	(7.4)
Lower frequency, %	10.36	19.75	30.34	31.37	9.81	1.65	1.72
Wind Speed, mph	(6.2)	(7.9)	(8.4)	(8.4)	(6.8)	(5.6)	(4.5)
Fall (Sept, Oct, Nov)							
Upper frequency, %	3.29	3.49	10.83	37.37	31.65	8.12	5.60
Wind Speed, mph	(5.3)	(6.1)	(8.1)	(10.3)	(9.4)	(8.1)	(7.1)
Lower frequency, %	9.95	20.35	33.55	28.80	9.73	1.74	1.01
Wind Speed, mph	(6.9)	(8.6)	(9.1)	(8.8)	(7.1)	(5.6)	(5.5)
Winter (Dec, Jan, Feb)							
Upper frequency,%	2.66	2.94	9.08	45.55	30.72	6.41	3.03
Wind Speed, mph	(4.9)	(6.1)	(8.1)	(11.5)	(10.1)	(8.3)	(7.3)
Lower frequency,%	5.88	17.55	37.73	41.29	10.25	1.43	1.33
Wind Speed, mph	(6.3)	(8.2)	(9.2)	(9.8)	(7.4)	(6.4)	(3.1)
Annual							
Upper frequency,%	3.83	4.06	12.04	41.08	29.04	6.63	3.43
Wind Speed, mph	(5.1)	(6.3)	(8.2)	(10.7)	(9.6)	(8.1)	(7.3)
Lower frequency,%	8.04	18.84	32.85	30.91	8.60	1.42	1.04
Wind Speed, mph	(6.7)	(8.9)	(9.4)	(9.5)	(7.2)	(5.6)	(4.6)

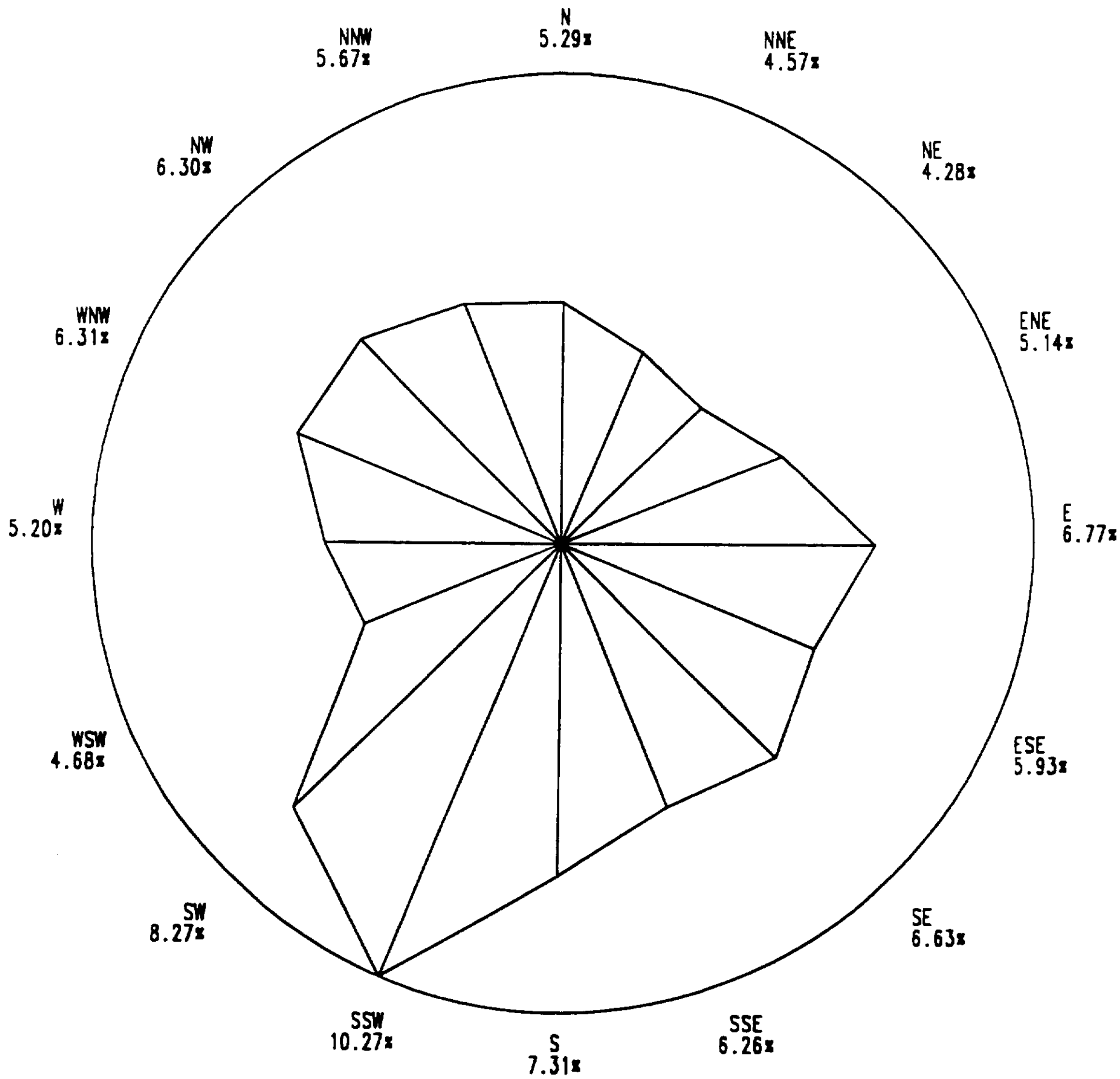
Table 2.2-10
METEOROLOGICAL INFORMATION DISPLAY LOCATIONS

	Transmitted Locations		
Primary Tower Parameters	ERFDAS Data base	Control Room	Remote Interrogation
Wind direction (upper)	x	x	x
Wind speed (upper)	x	x	x
Sigma theta (upper)			x
Wind direction (lower)	x	x	x
Wind speed (lower)	x	x	x
Sigma theta (lower)			x
Ambient temperature (lower)	x	x	x
Dewpoint temperature (lower)			x
Delta ambient temperature (upper-lower)	x	x	x
Precipitation			x

	Transmitted Locations		
Backup Tower Parameters	ERFDAS Data base	Control Room	Remote Interrogation
Wind speed	x	x	x
Wind speed	x	x	x
Sigma theta	x	x	x

Note: All parameters going to the ERFDAS data base will be available for printout in the TSC and CERC. The control room parameters are hardwired. Remote readout of instrumentation is available at the primary and backup meteorological sites and from the Air Quality Department’s system computer.

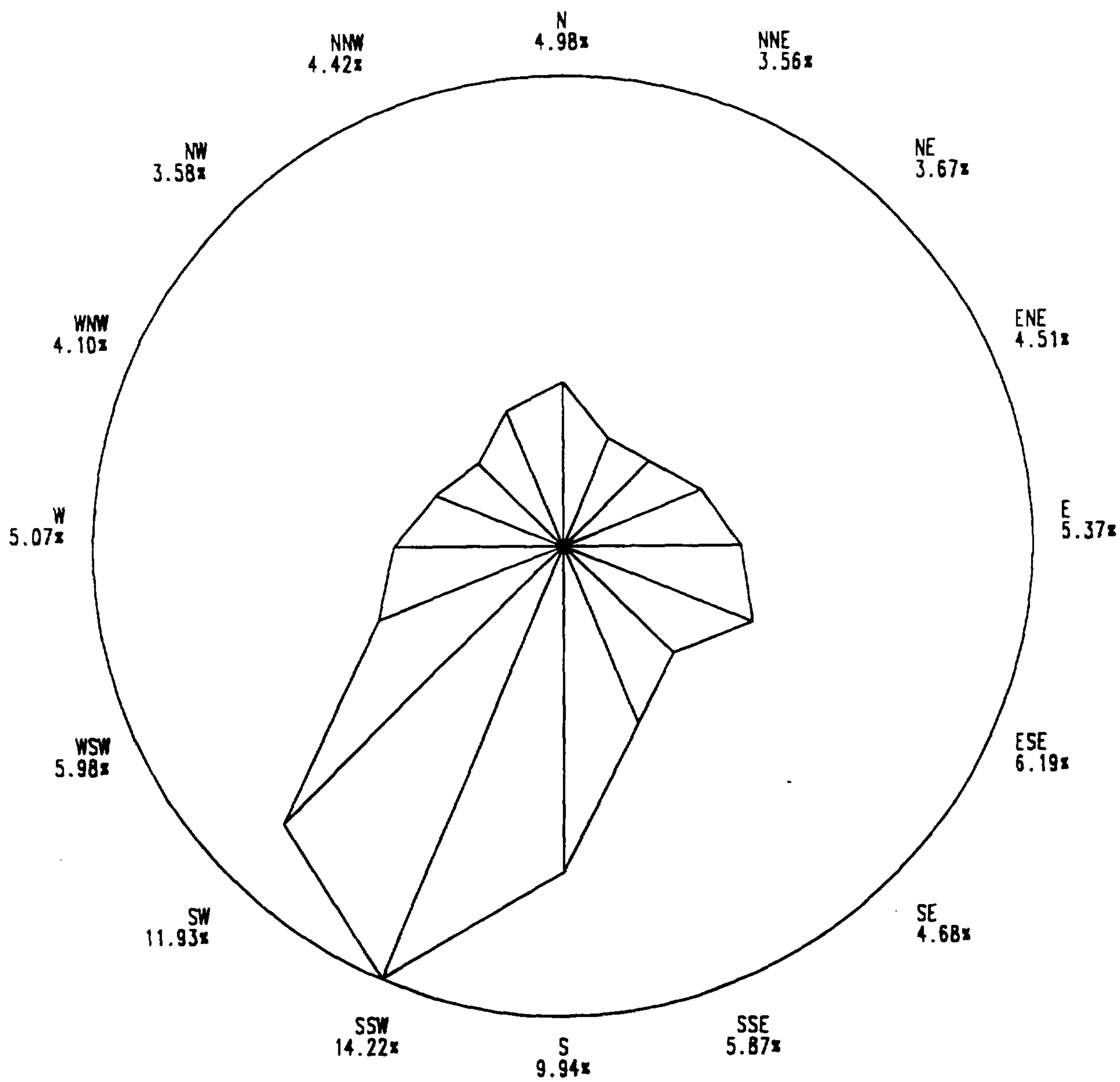
Figure 2.2-1
SURRY SEASONAL WIND DIRECTION ROSES
LOW LEVEL WINDS 1974 - 1987 SEASON = SPRING



S0202001

Hours Calm = 289
Total Hours = 28,353
Percent Calm = 1.02 %

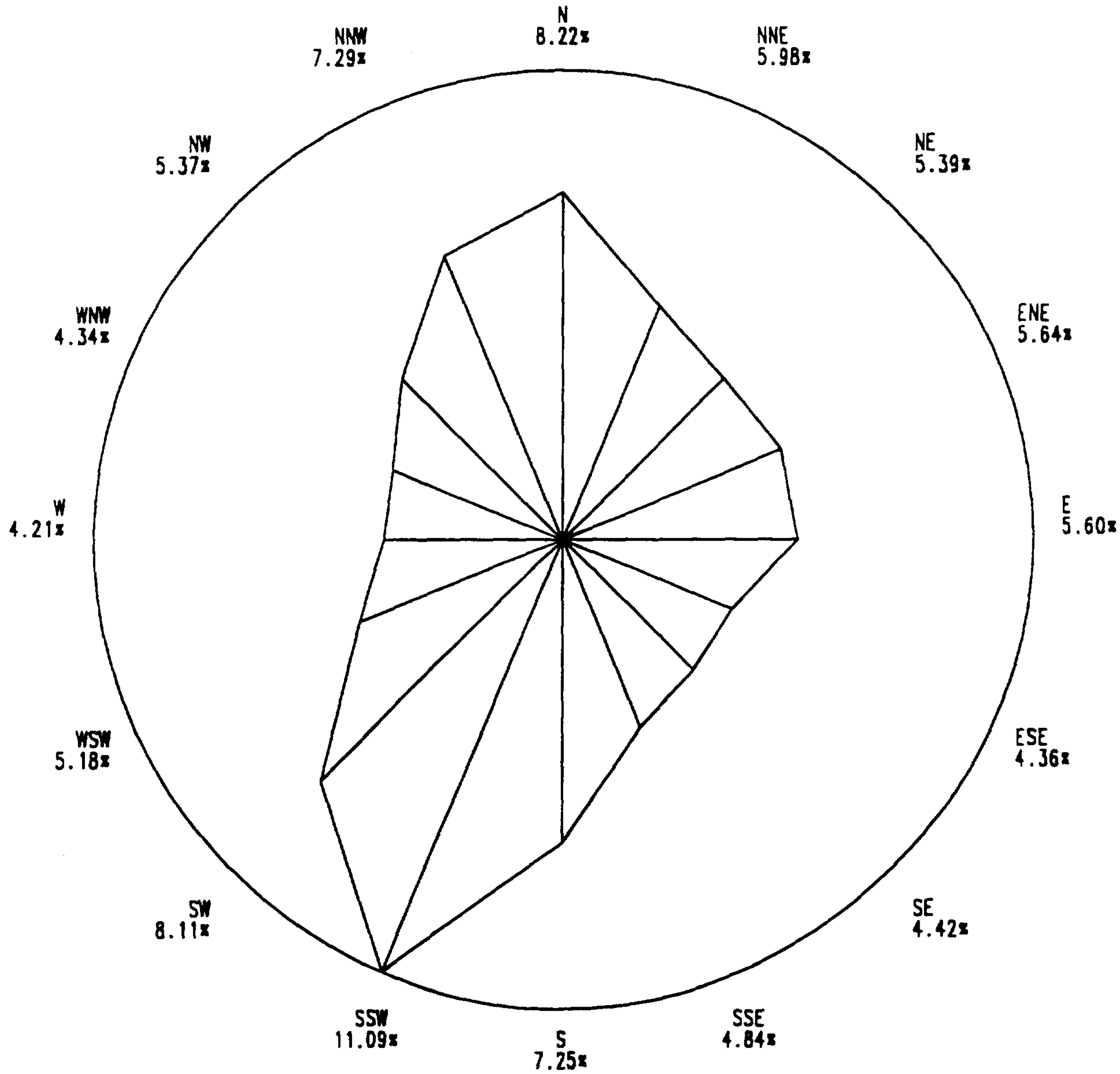
Figure 2.2-2
SURRY SEASONAL WIND DIRECTION ROSES
LOW LEVEL WINDS 1974 - 1987 SEASON = SUMMER



S0202002

Hours Calm = 514
Total Hours = 27,725
Percent Calm = 1.85 %

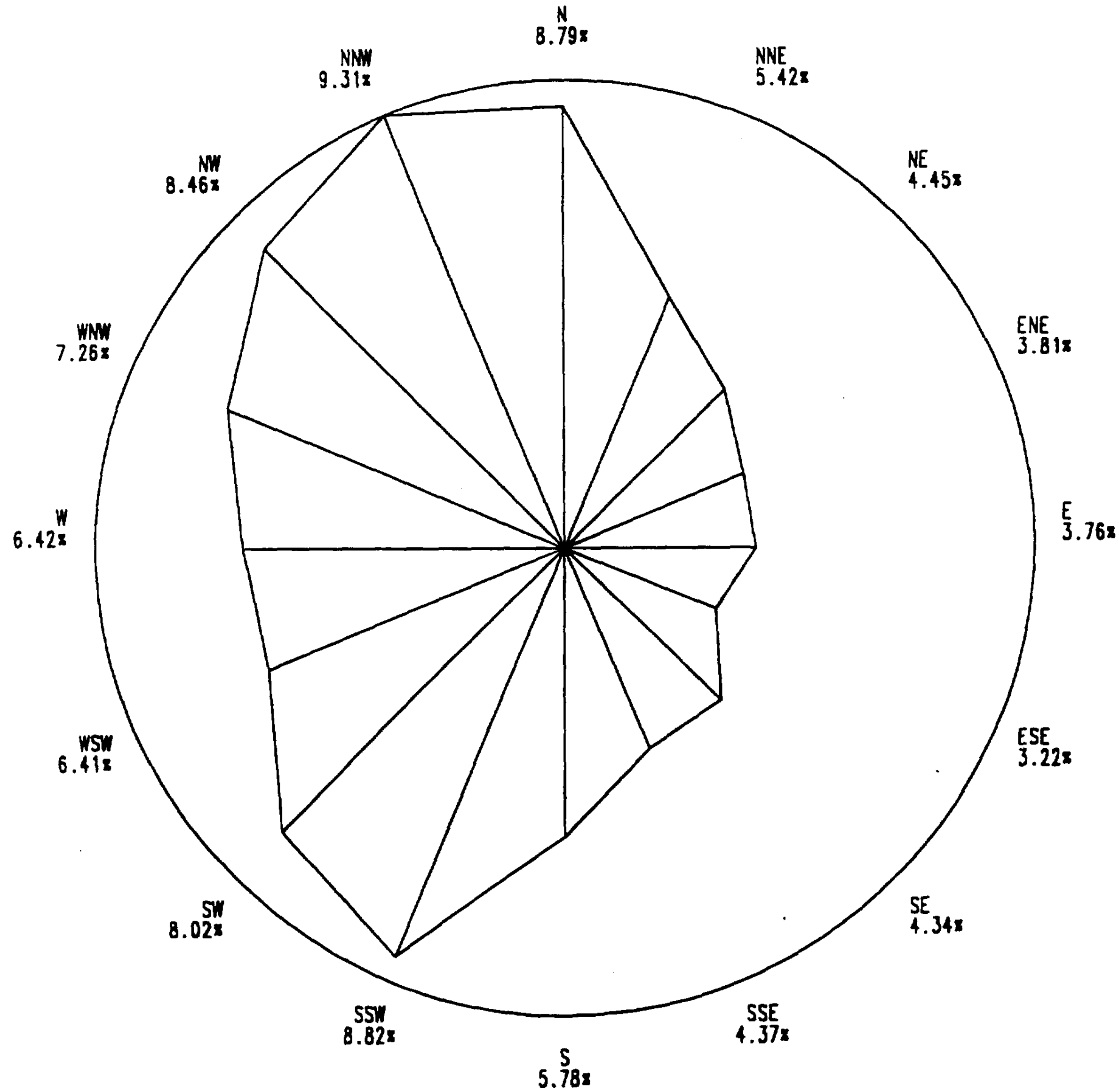
Figure 2.2-3
SURRY SEASONAL WIND DIRECTION ROSES
LOW LEVEL WINDS 1974 - 1987 SEASON = FALL



Hours Calm = 749
Total Hours = 28,508
Percent Calm = 2.63 %

S0202003

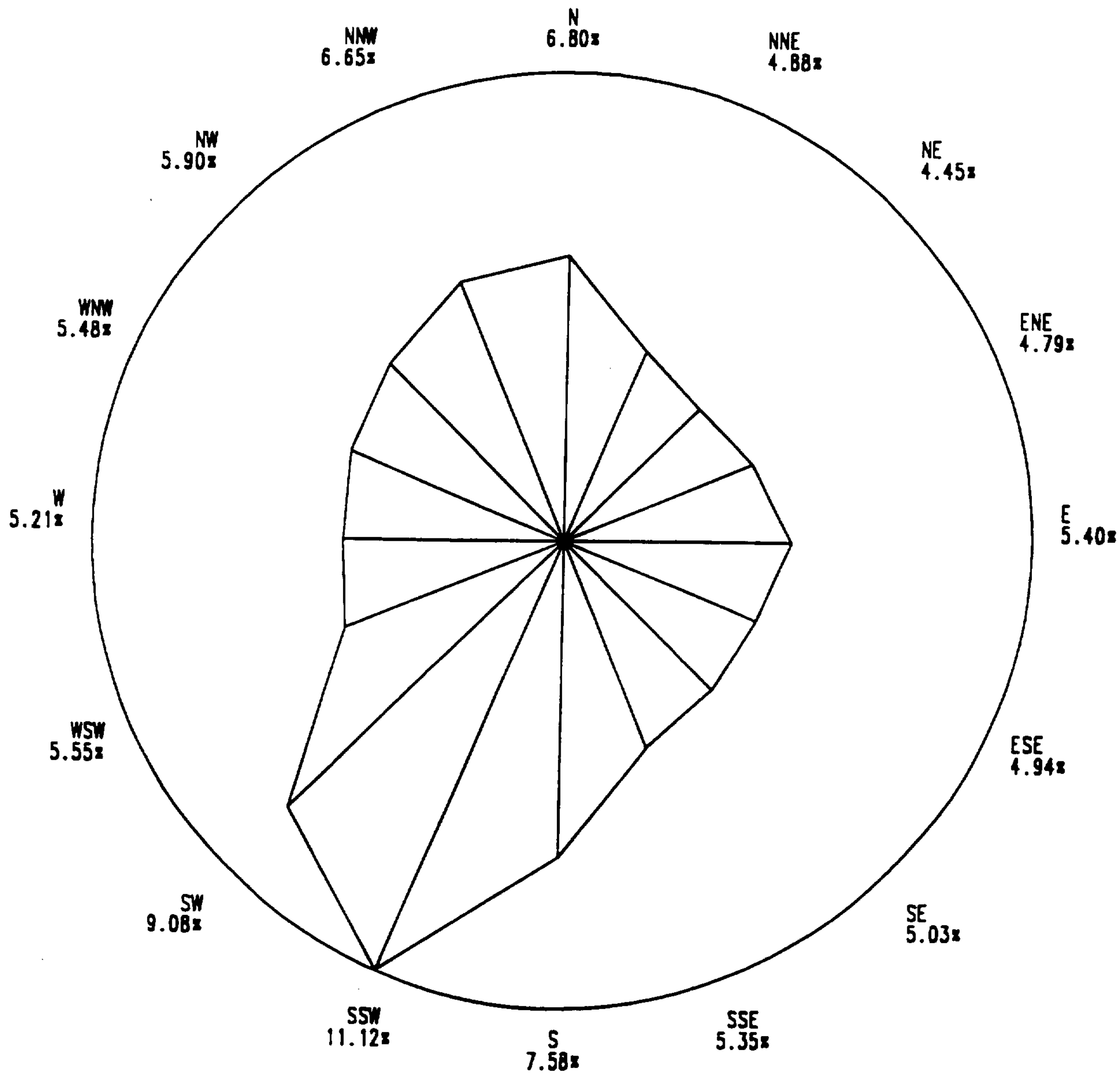
Figure 2.2-4
SURRY SEASONAL WIND DIRECTION ROSES
LOW LEVEL WINDS 1974 - 1987 SEASON = WINTER



S0202004

Hours Calm = 343
Total Hours = 26,595
Percent Calm = 1.29 %

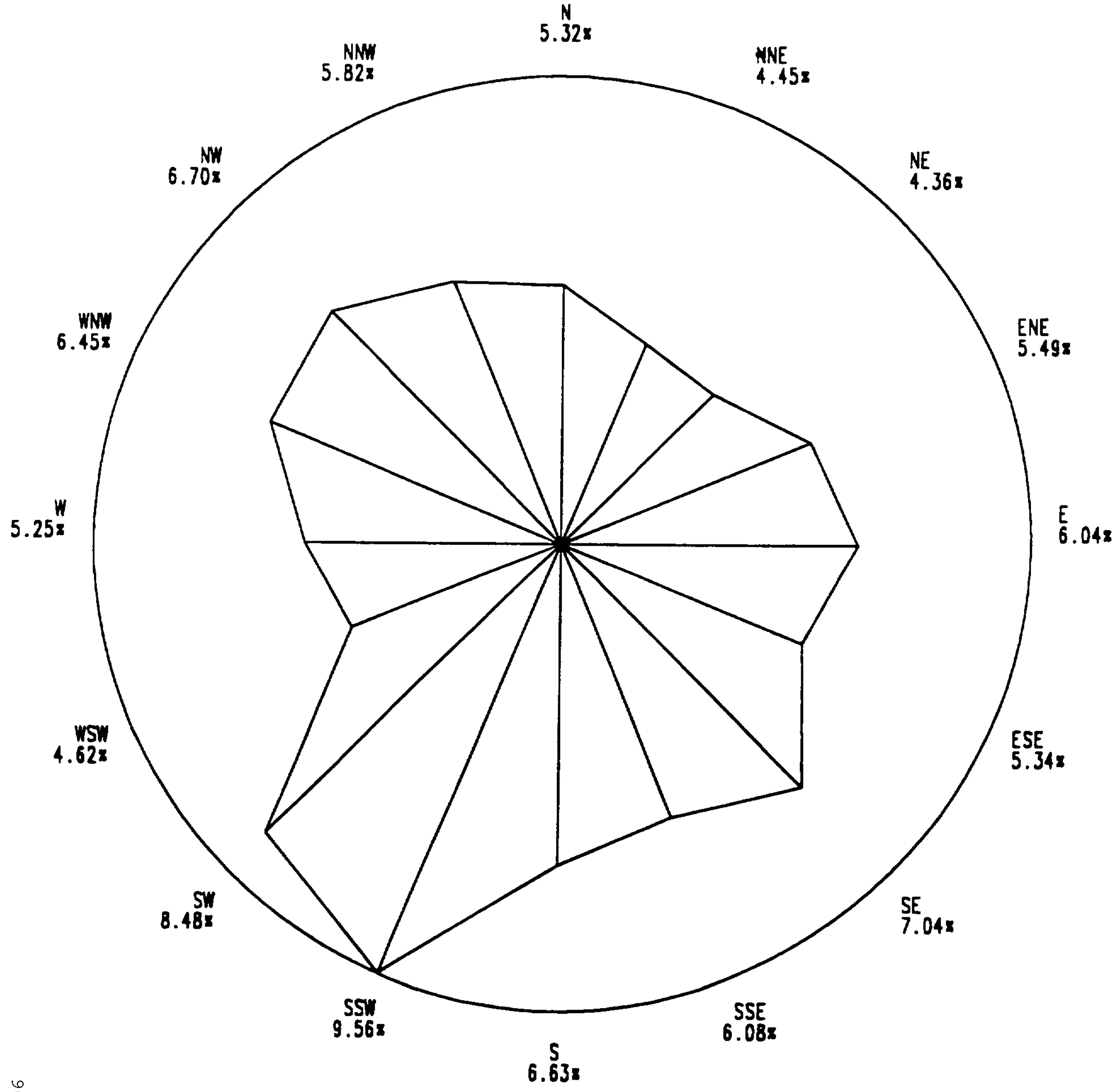
Figure 2.2-5
SURRY SEASONAL WIND DIRECTION ROSES
LOW LEVEL WINDS 1974 - 1987 SEASON = OVERALL



Hours Calm = 1895
Total Hours = 111,181
Percent Calm = 1.70 %

S0202005

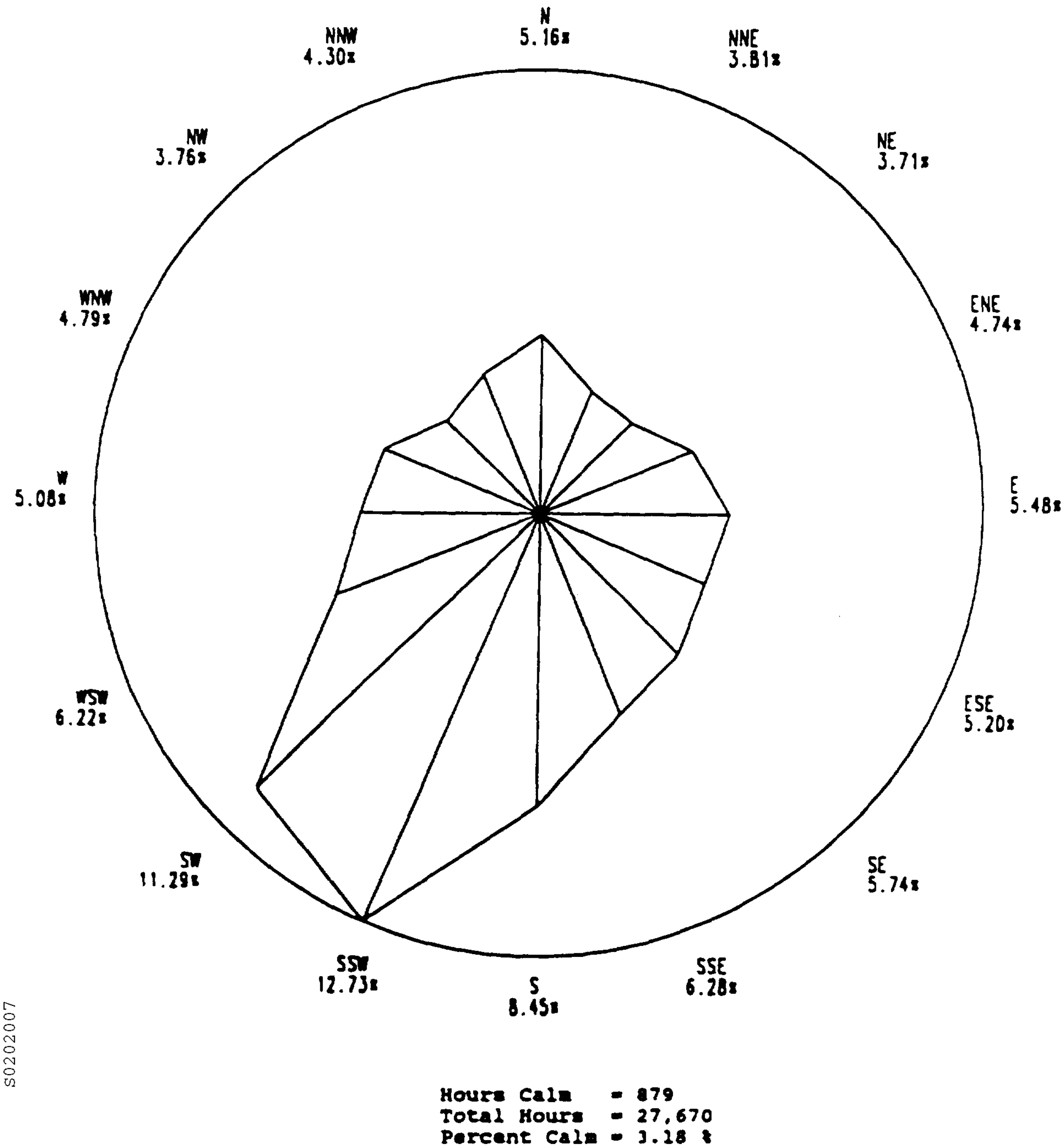
Figure 2.2-6
SURRY SEASONAL WIND DIRECTION ROSES HIGH LEVEL
WINDS 1974 - 1987 SEASON = SPRING



Hours Calm = 633
Total Hours = 27,670
Percent Calm = 2.28 %

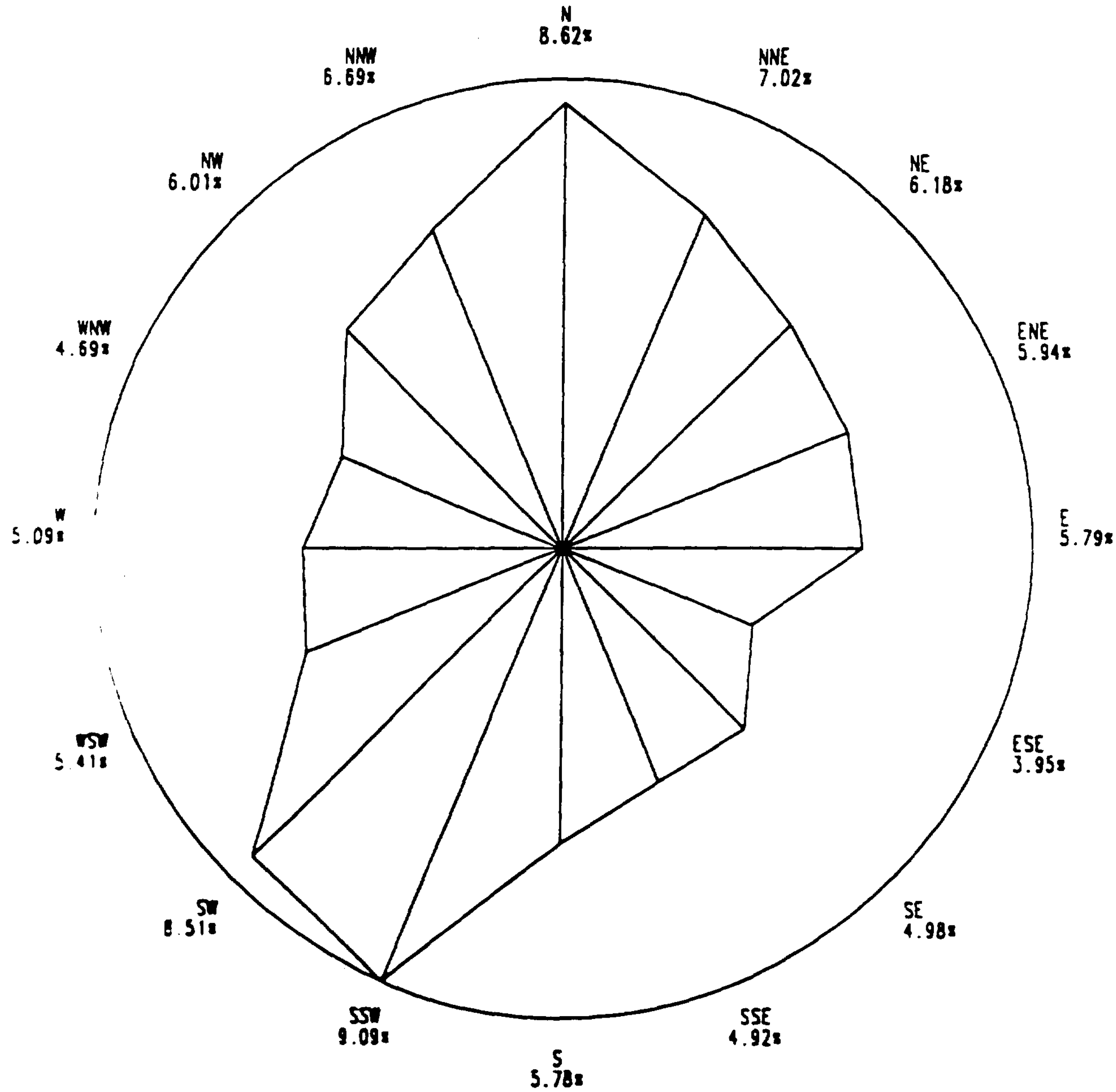
S0202006

Figure 2.2-7
SURRY SEASONAL WIND DIRECTION ROSES HIGH LEVEL WINDS 1974 - 1987 SEASON = SUMMER



S0202007

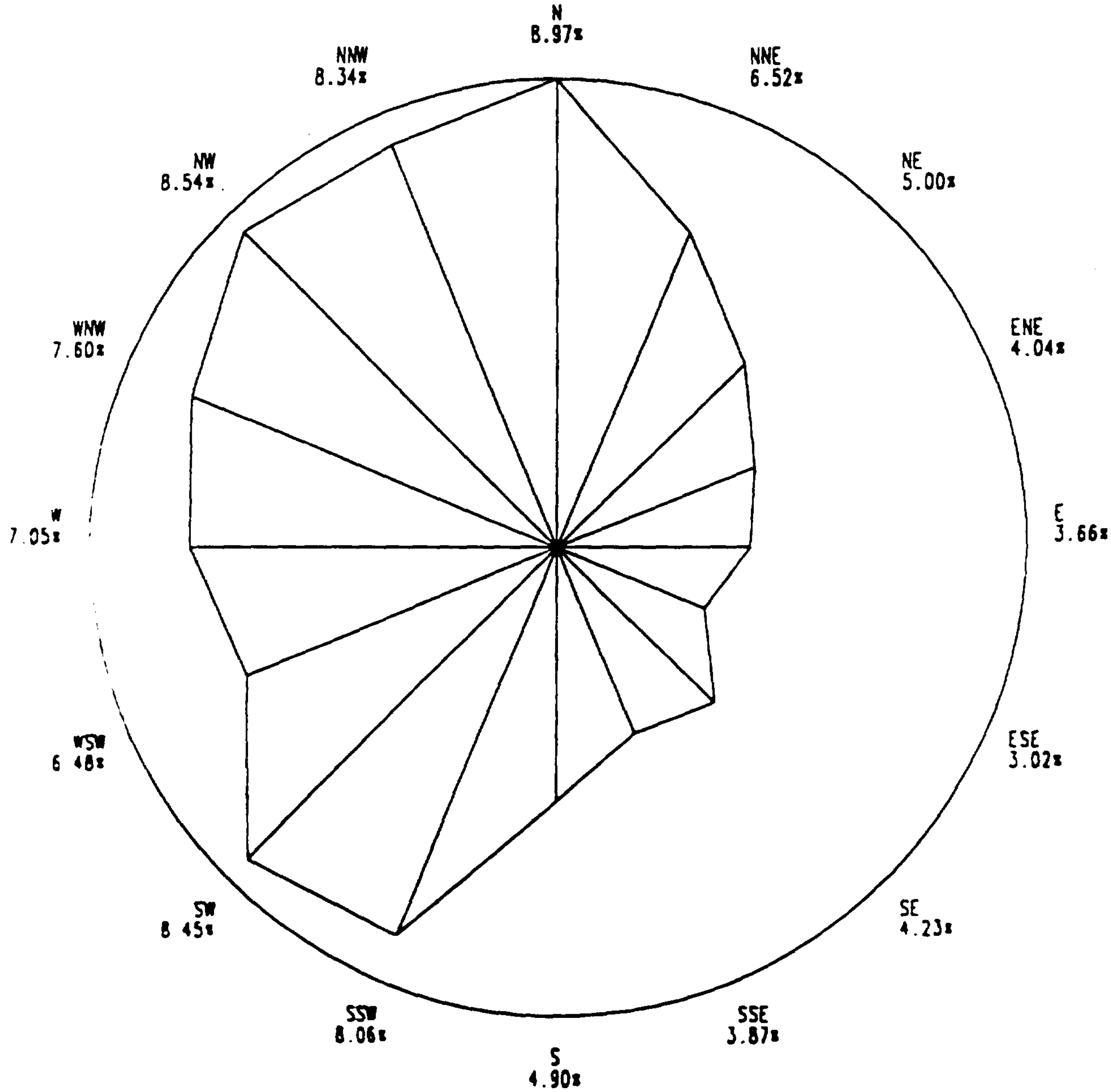
Figure 2.2-8
SURRY SEASONAL WIND DIRECTION ROSES HIGH LEVEL
WINDS 1974 - 1987 SEASON = FALL



Hours Calm = 368
Total Hours = 29,555
Percent Calm = 1.24 %

S0202008

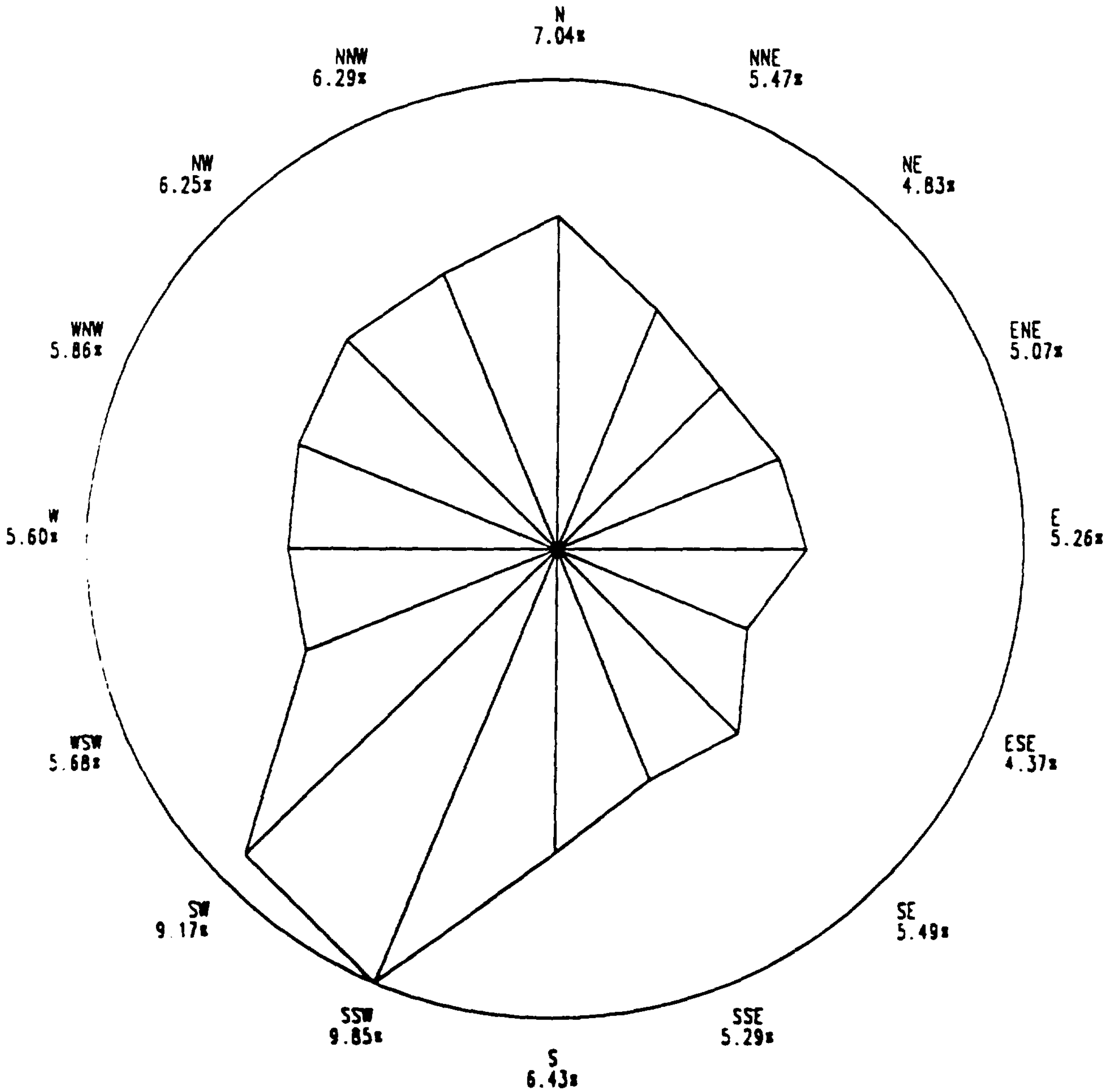
Figure 2.2-9
SURRY SEASONAL WIND DIRECTION ROSES HIGH LEVEL
WINDS 1974 - 1987 SEASON = WINTER



Hours Calm = 324
Total Hours = 27,357
Percent Calm = 1.18 %

S0202009

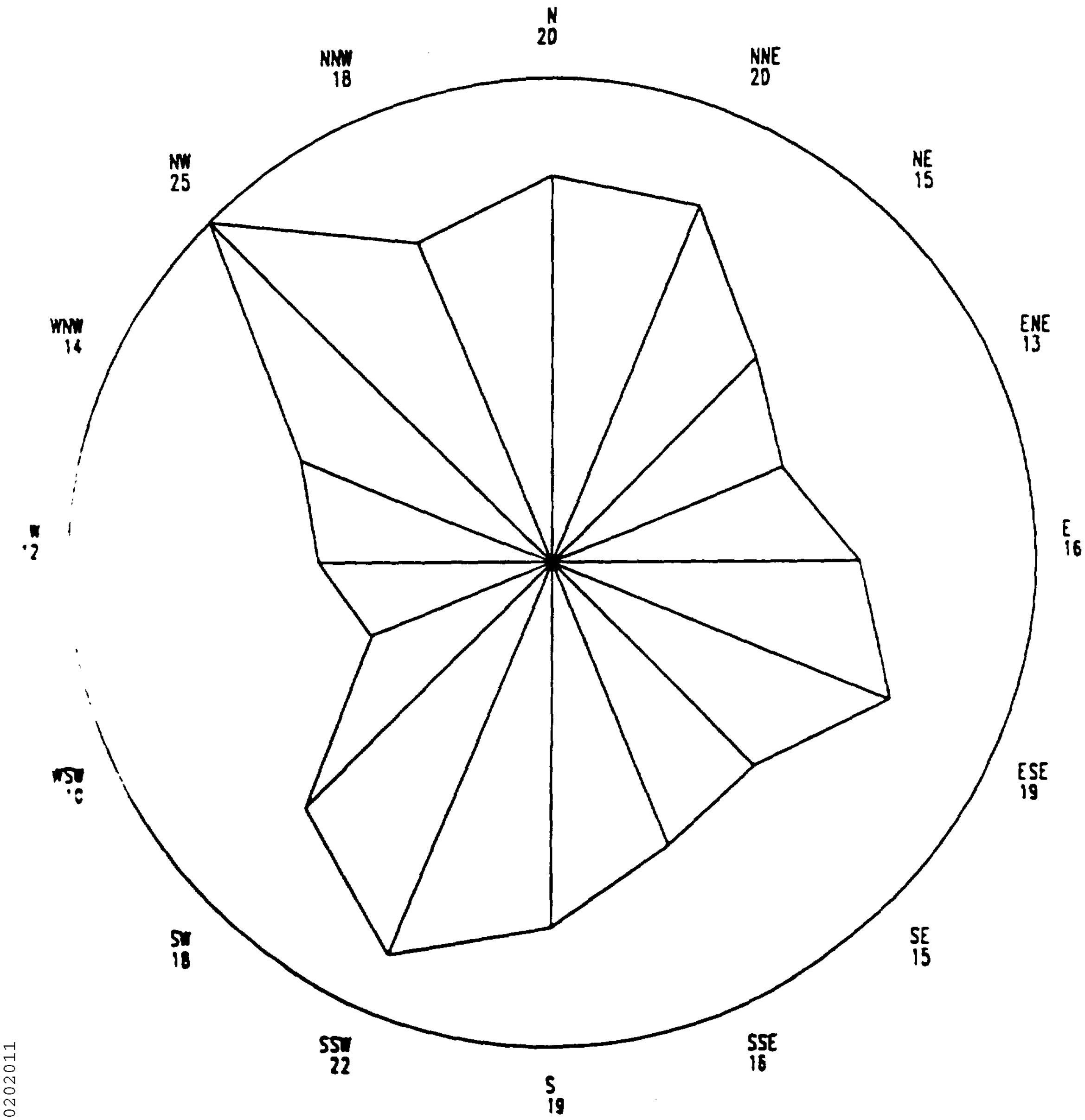
Figure 2.2-10
SURRY SEASONAL WIND DIRECTION ROSES
HIGH LEVEL WINDS 1974 - 1987 SEASON = OVERALL



Hours Calm = 2204
Total Hours = 112,252
Percent Calm = 1.96 %

S0202010

Figure 2.2-11
SURRY SEASONAL WIND PERSISTENCE ROSES LOW LEVEL WINDS 1974 - 1987 SEASON = SPRING



S0202011

Figure 2.2-12
SURRY SEASONAL WIND PERSISTENCE ROSES LOW LEVEL WINDS 1974 - 1987 SEASON = SUMMER

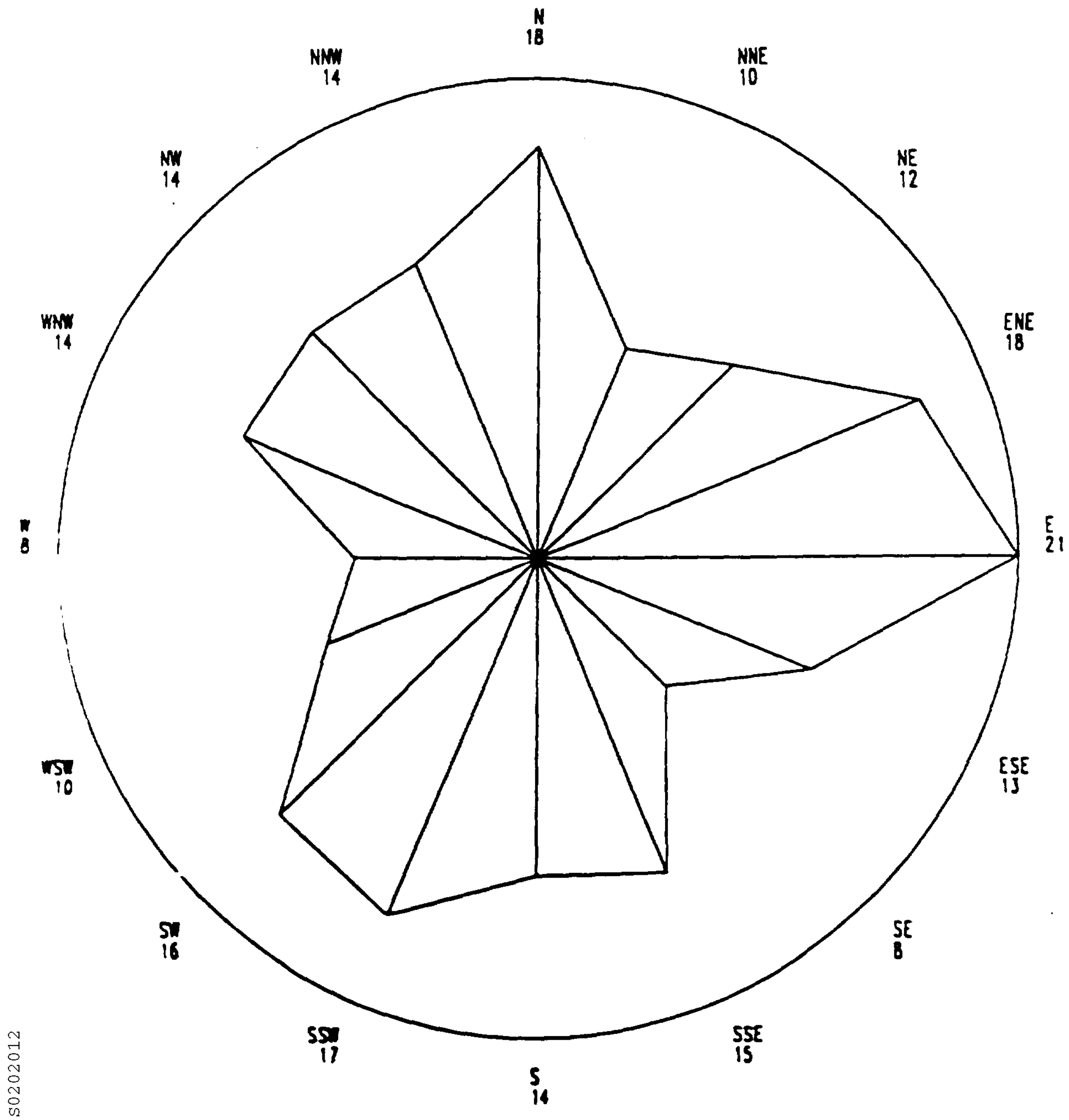


Figure 2.2-13
SURRY SEASONAL WIND PERSISTENCE ROSES LOW LEVEL WINDS 1974 - 1987 SEASON = FALL

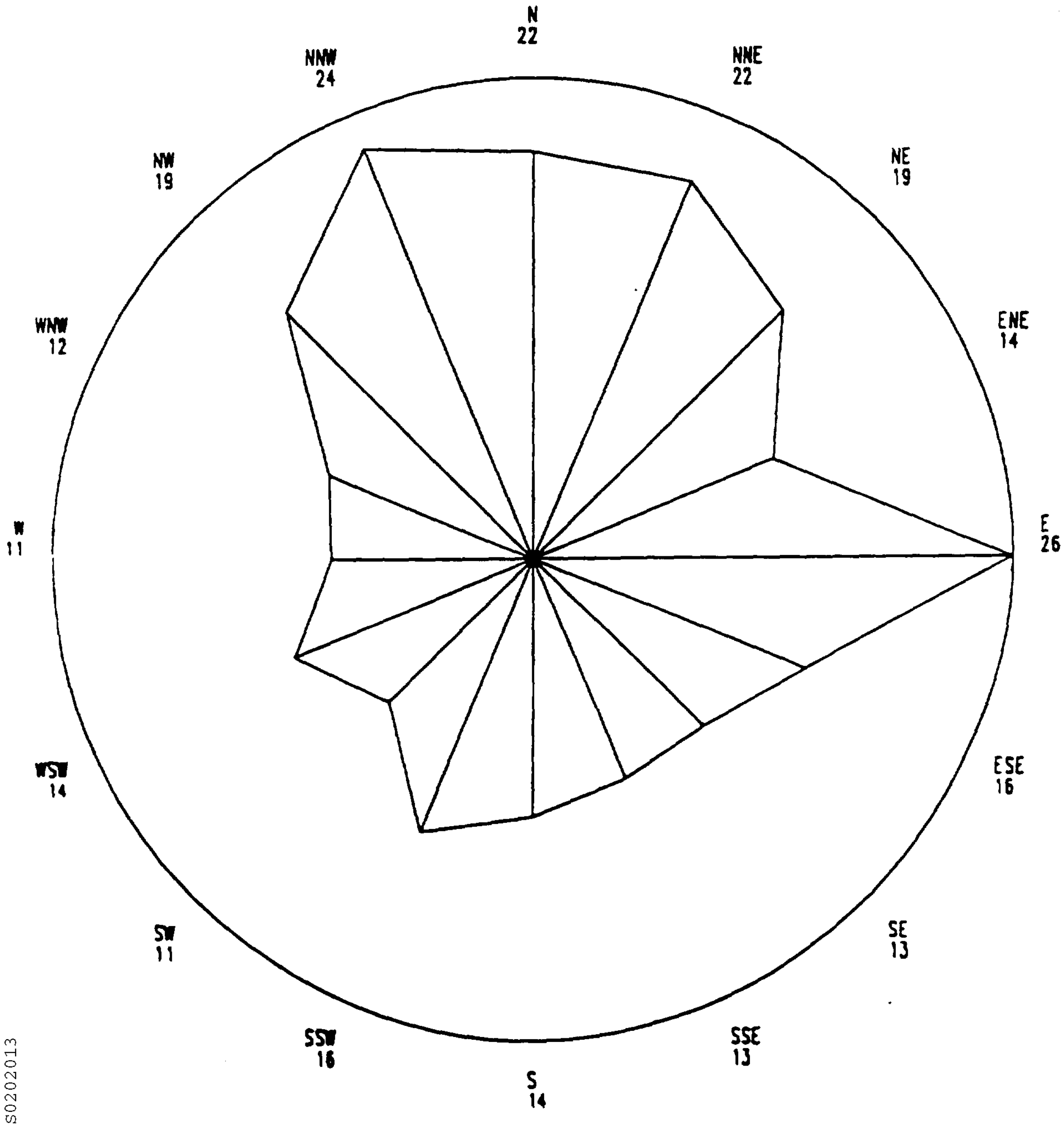
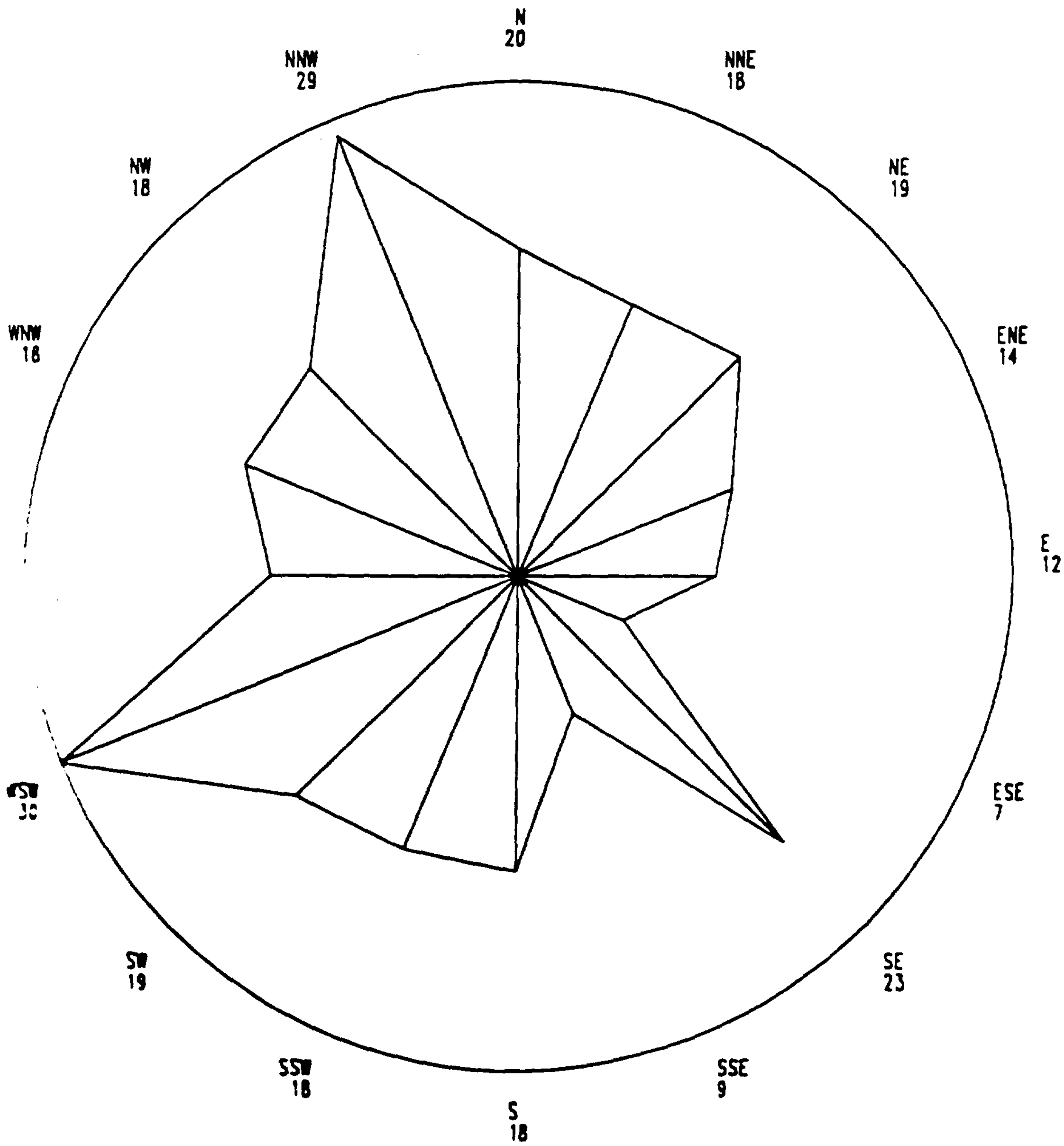


Figure 2.2-14
SURRY SEASONAL WIND PERSISTENCE ROSES
LOW LEVEL WINDS 1974 - 1987 SEASON = WINTER



S0202014

Figure 2.2-15
SURRY SEASONAL WIND PERSISTENCE ROSES
LOW LEVEL WINDS 1974 - 1987 SEASON = OVERALL

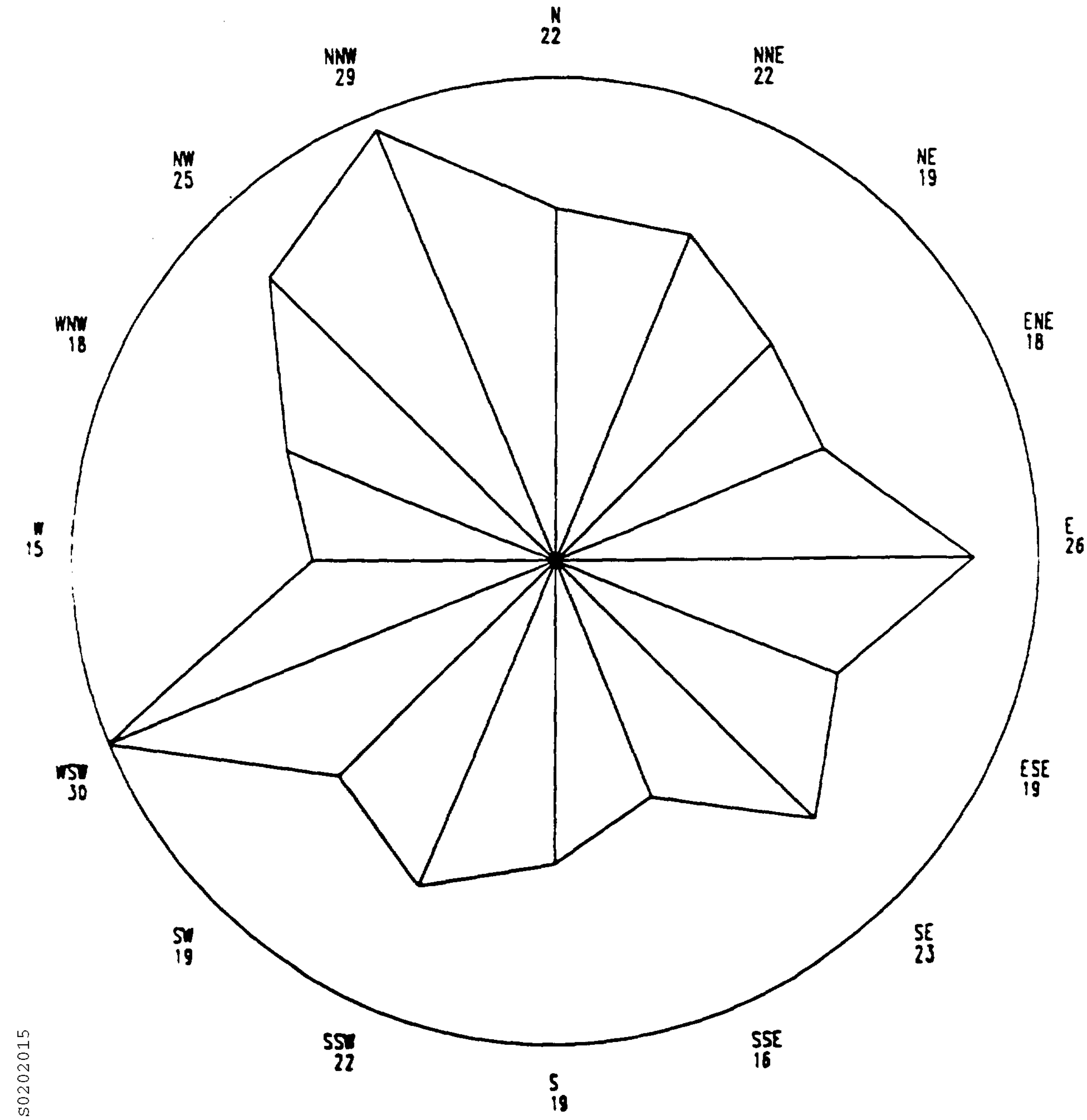


Figure 2.2-16
SURRY SEASONAL WIND PERSISTENCE ROSES
HIGH LEVEL WINDS 1974 - 1987 SEASON = SPRING

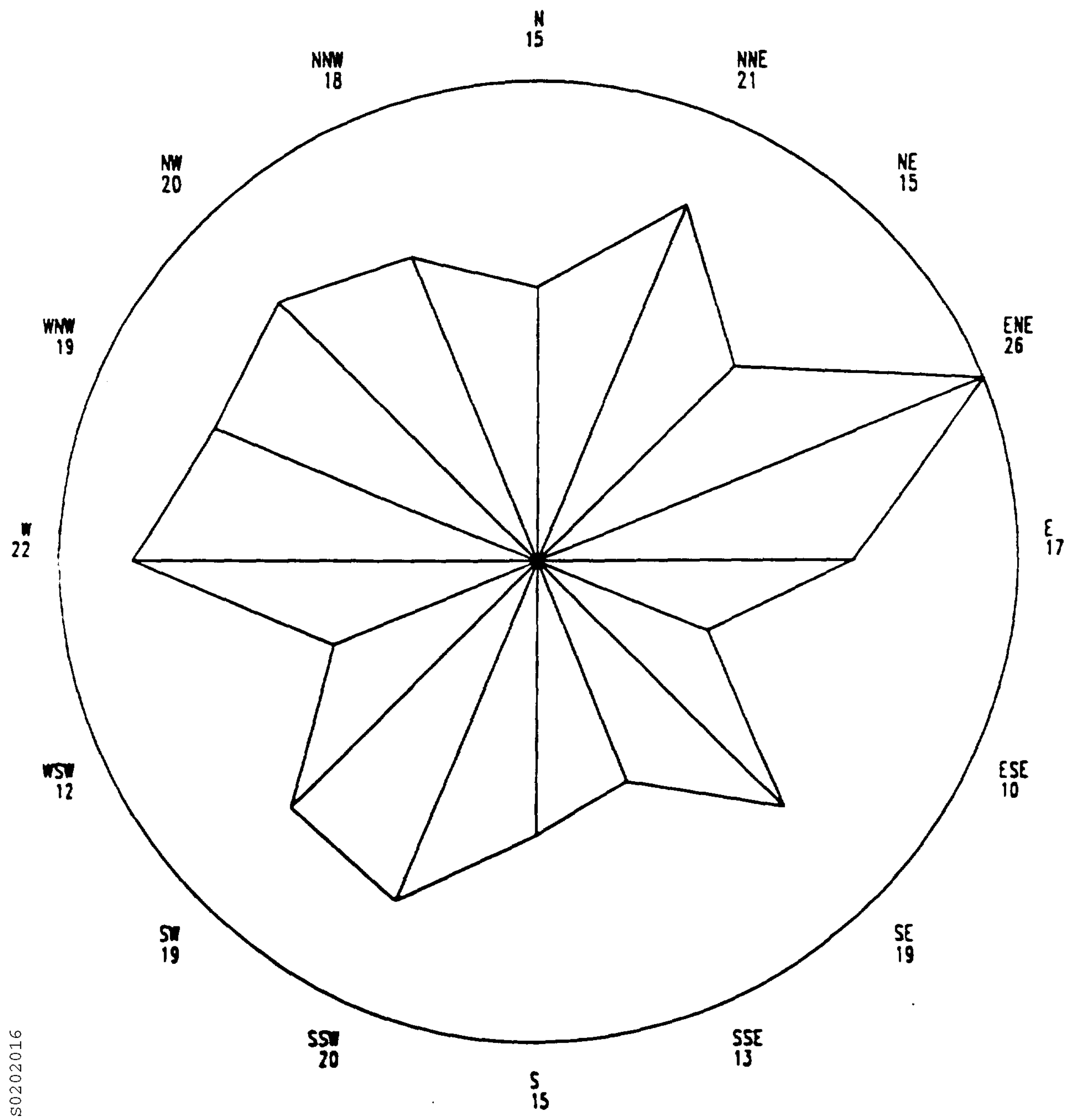
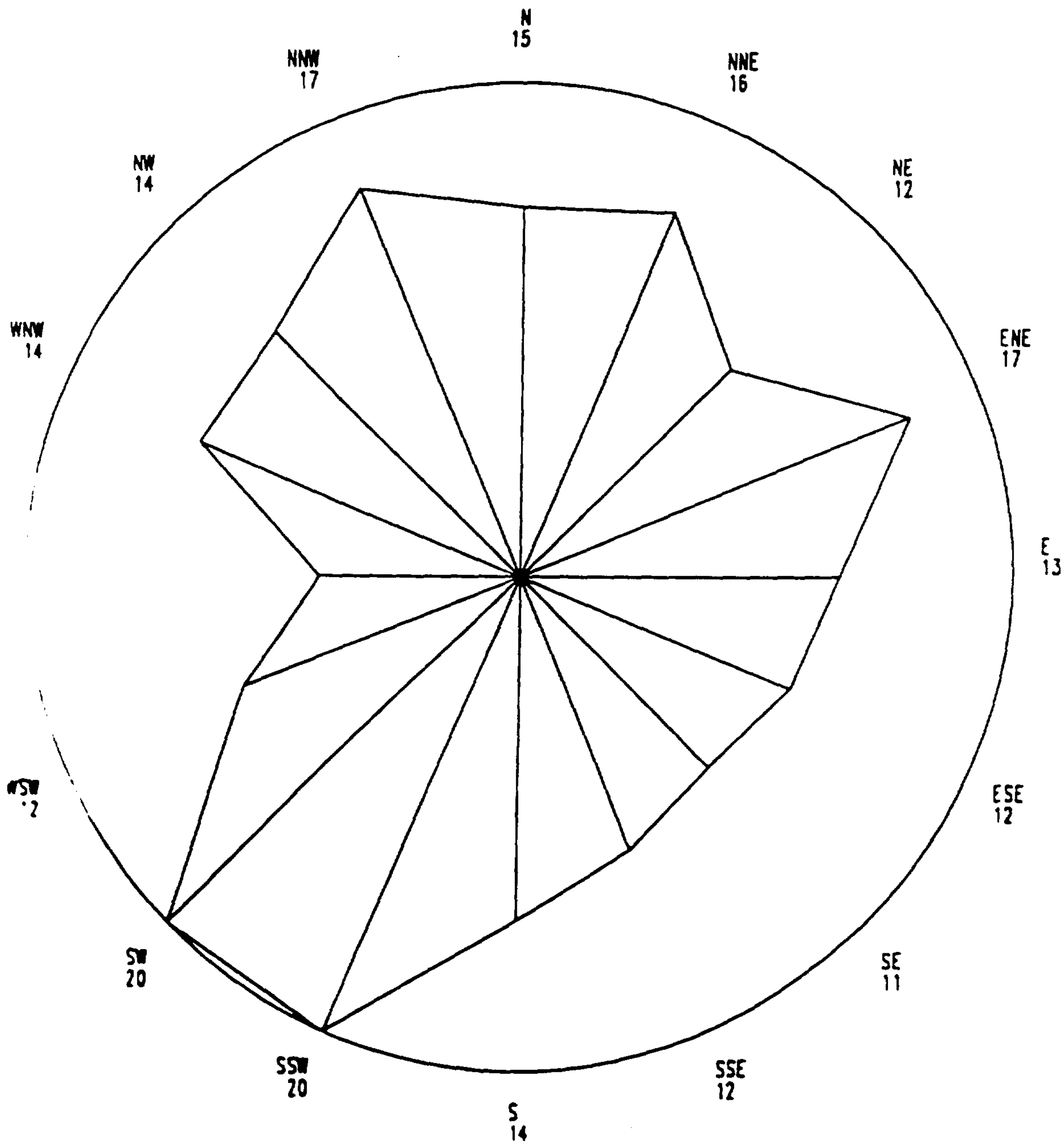
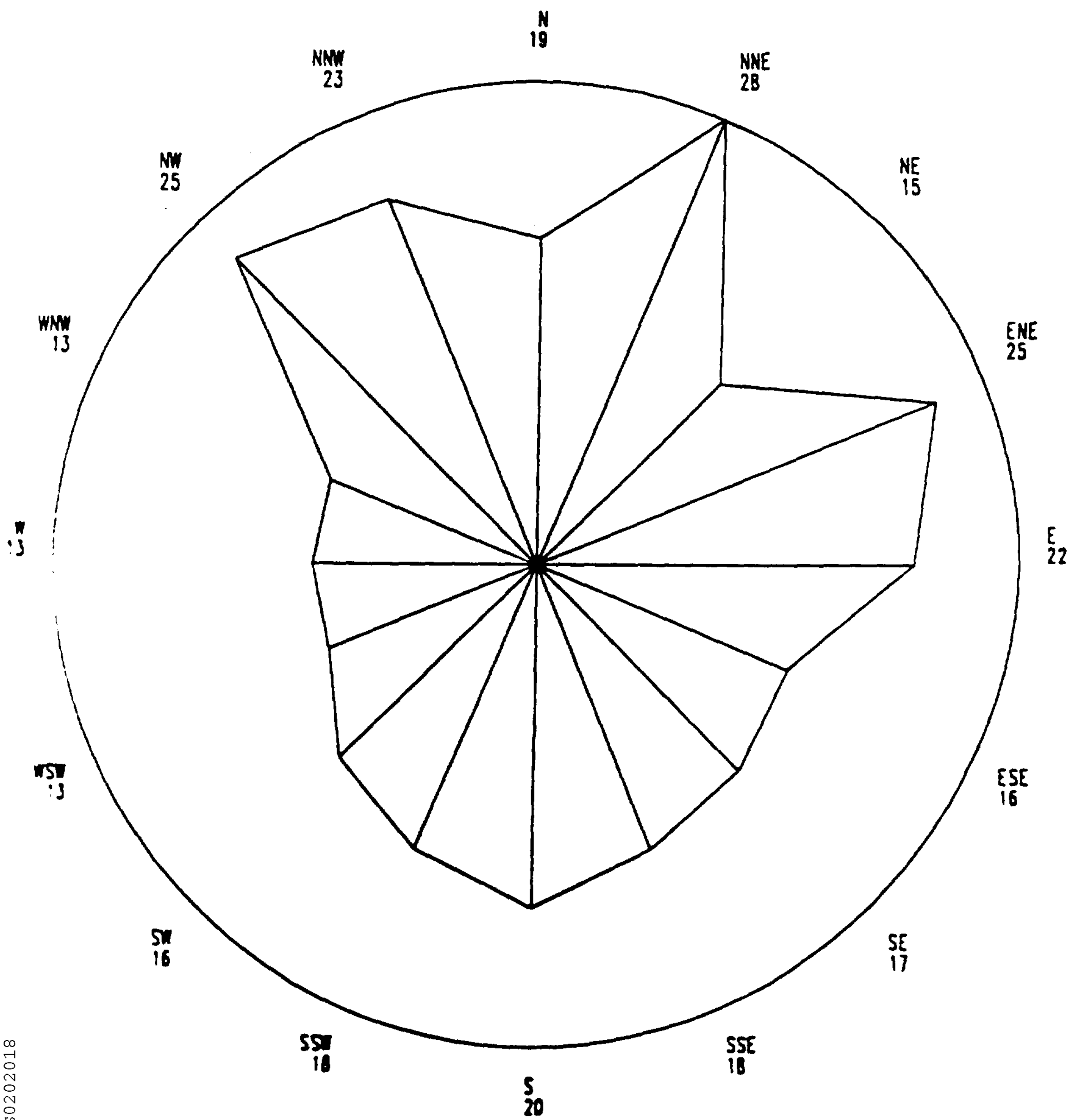


Figure 2.2-17
SURRY SEASONAL WIND PERSISTENCE ROSES
HIGH LEVEL WINDS 1974 - 1987 SEASON = SUMMER



S0202017

Figure 2.2-18
SURRY SEASONAL WIND PERSISTENCE ROSES
HIGH LEVEL WINDS 1974 - 1987 SEASON = FALL



S0202018

Figure 2.2-19
SURRY SEASONAL WIND PERSISTENCE ROSES
HIGH LEVEL WINDS 1974 - 1987 SEASON = WINTER

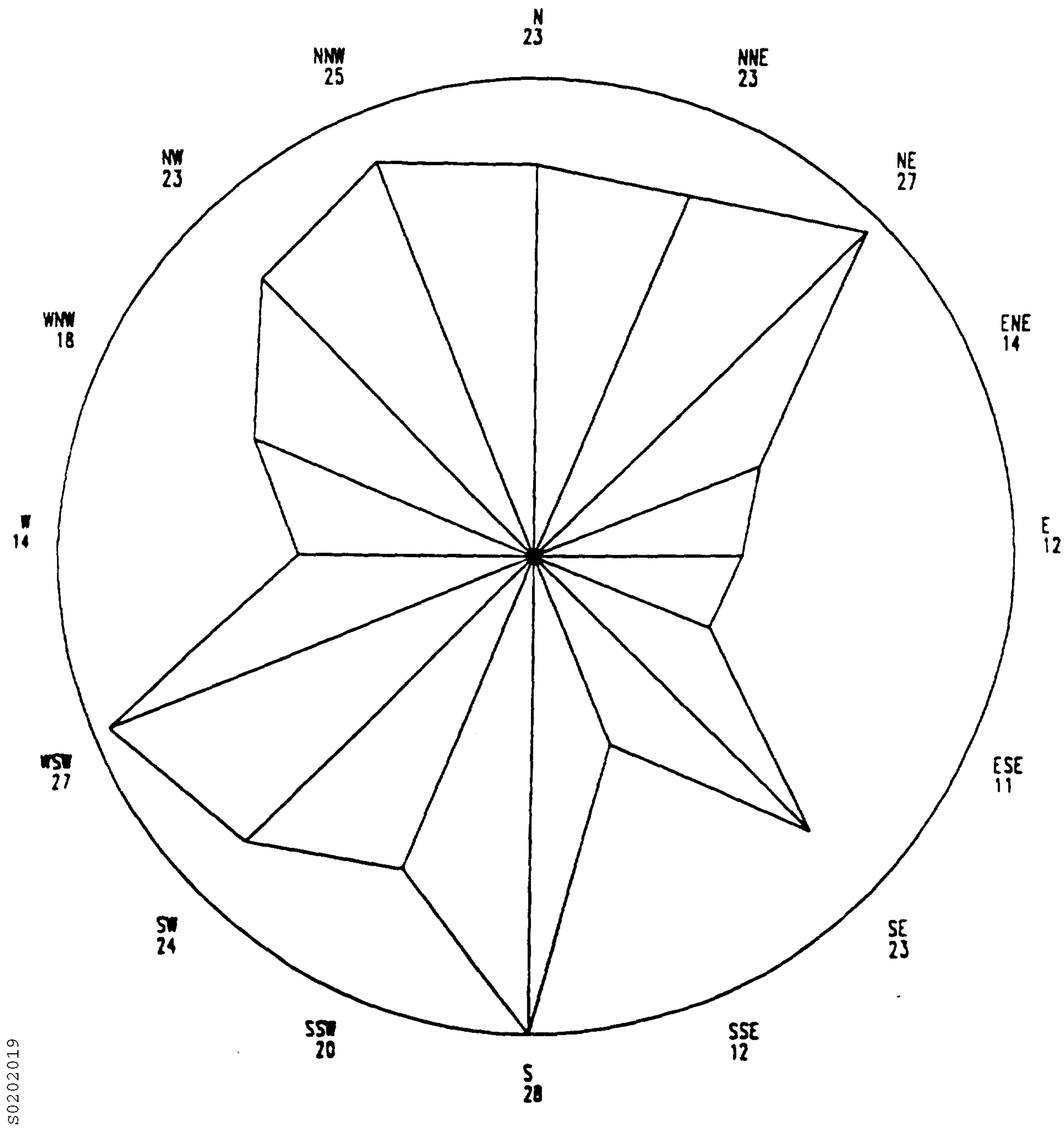


Figure 2.2-20
SURRY SEASONAL WIND PERSISTENCE ROSES
HIGH LEVEL WINDS 1974 - 1987 SEASON = OVERALL

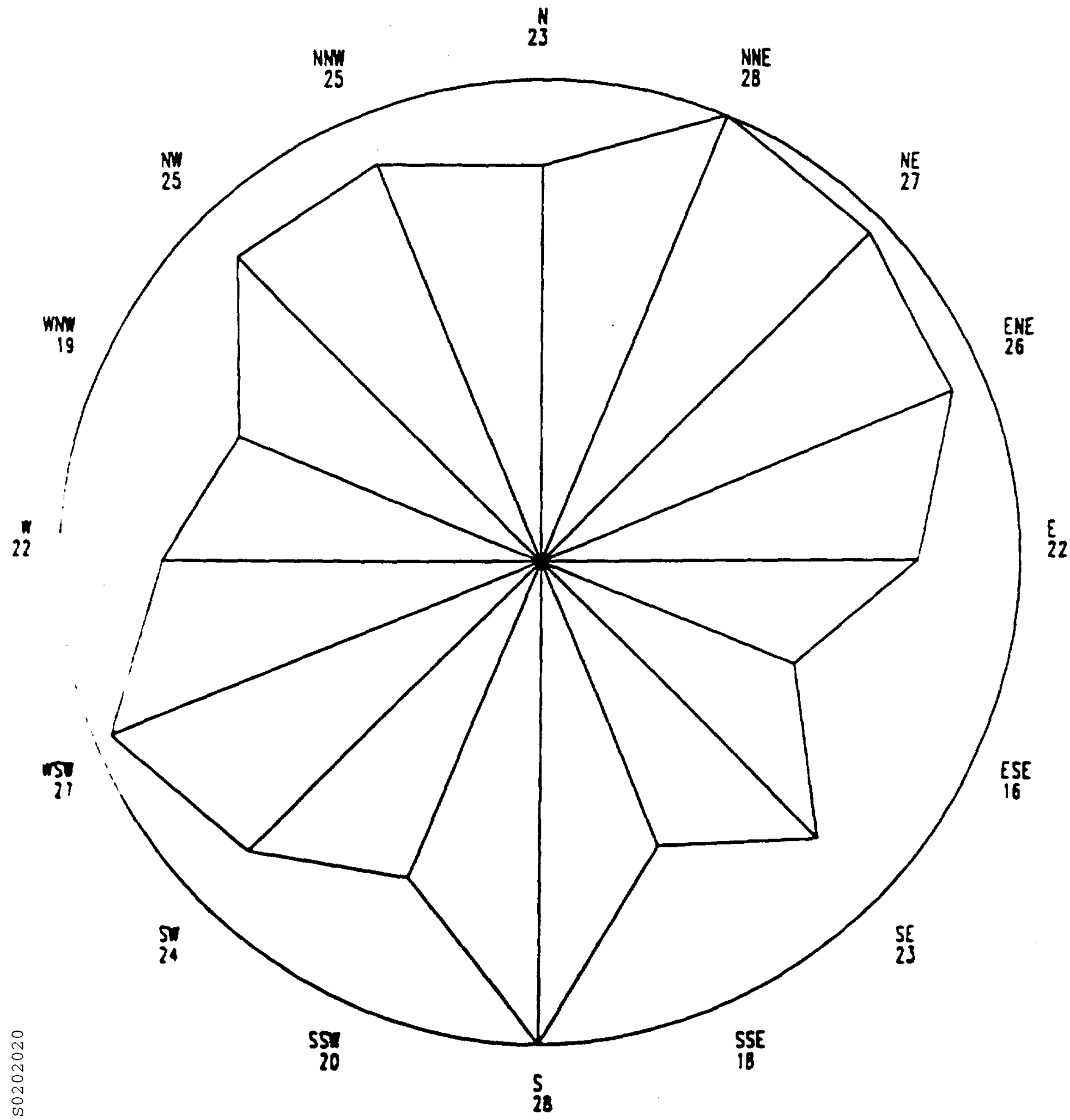
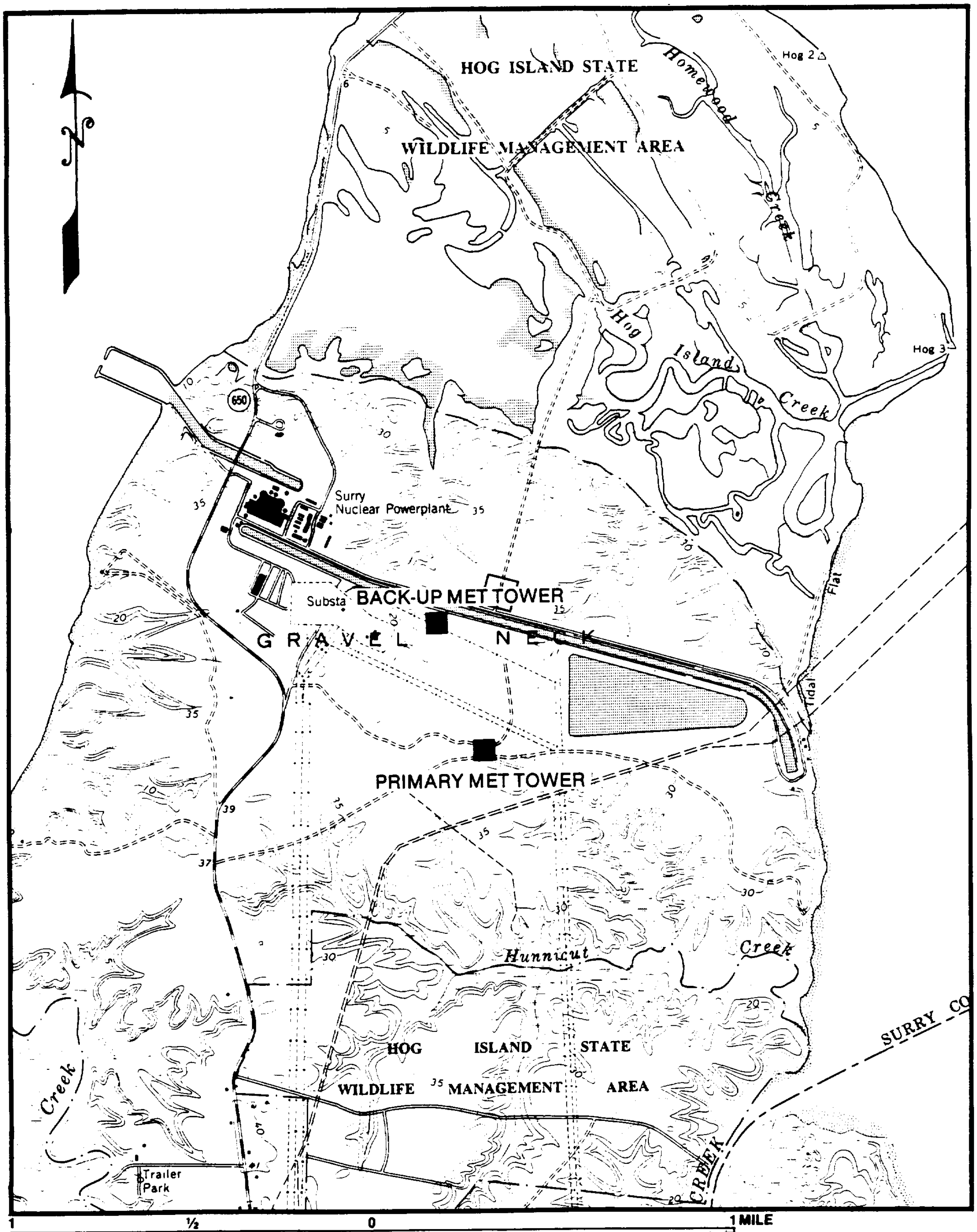


Figure 2.2-21
LOCATIONS OF METEOROLOGICAL TOWERS



S0202021

2.3 HYDROLOGY

2.3.1 Surface Water Hydrology

2.3.1.1 General

Much of the region is characterized by marshes, extensive swamps, small streams, and pocosins. Water tables are very near the surface throughout the entire area, accounting for the large amount of surface waters. Drainage throughout the area is towards Hampton Roads, near the mouth of the Chesapeake Bay, and on to the Atlantic Ocean via the James River.

The James River is formed by the junction of the Cowpasture and Jackson Rivers in Botetourt County, Virginia, and flows easterly 340 miles before emptying into Hampton Roads at Newport News, Virginia.

The flow of water in the James River at the site consists of three components:

1. Fresh water discharge from the James River watershed.

2. Flow due to the oscillatory ebb and flood of the tide.

3. FLOW due to the circulation pattern caused by intrusion of saline water within the estuary.

The drainage area of the James River above the station site is 9517 square miles. The drainage area above the nearest gauge on the main stem of the James River near Richmond is 6757 square miles. An additional 1638 square miles of drainage area of tributaries between Richmond and the plant site is gauged, leaving 1122 square miles ungauged. Discharge records for the gauged tributaries below Richmond were used to estimate the discharge from the ungauged areas, and the total mean monthly discharge for each month for the period October 1934 to September 1993 was computed by summing the discharges from the gauged and ungauged watershed areas. These data are shown in Table 2.3-1 (References 1, 2, & 20).

In compiling the river discharge data, monthly mean flows have been used rather than daily mean flows. This choice was made because the cross-sectional area of the waterway in the 50 miles or so of tidal water between the station and Richmond increases significantly when compared with the stream above Richmond, and there is also a somewhat irregular, but significant, progressive increase in the cross-sectional area in this reach with distance downstream. The mean travel time for a flow of 14,000 cfs (a flow that is exceeded only 25% of the time) from Richmond to the site exceeds 20 days. Therefore, it can be assumed that short-period fluctuations in discharge at Richmond are considerably dampened at the station site. Further, within the estuary proper there is considerable inertia in the response of the salinity pattern and the net non-tidal circulation to rapid variations in river discharge, thereby providing additional damping.

The 85-mile stretch of the James River between Richmond and the mouth of the river is subjected to tidal motion and is hence a tidal estuary. The site is located in the transition region between the fresh water tidal river and the saline waters of the estuary proper. At a river discharge of about 10,000 cfs, the upstream portion of the site is in the fresh water river, and the salinity at the downstream side of the site is about 1 part/thousand. For river discharges less than 10,000 cfs (a condition occurring approximately 60% of the time), the water on both the upstream and downstream sides of the site will have varying concentrations of ocean-derived salts, depending on river discharge.

The tide in the James River is a semidiurnal tide, with two high waters and two low waters each lunar day of 24.84 hours. The oscillatory ebb and flood of this tide constitute the dominant motion in the waterway in the vicinity of the site. The net downstream flow required to discharge the fresh water seaward through any waterway cross section represents but a small fraction of the tidal flows.

The U. S. Coast and Geodetic Survey (USC&GS) tidal current tables (Reference 3) show that the ebb current is longer and stronger than the flood current at the site. The average of maximum ebb currents is 1.3 knots (2.2 ft/sec) and the average of maximum flood currents is 1.1 knots (1.9 ft/sec). During spring tides, the ebb currents reach a maximum of 1.9 knots (3.2 ft/sec) and the flood currents a maximum of 1.6 knots (2.8 ft/sec). During the typical tidal period of 12 hours, 25 minutes, the current, on the average, will ebb for 7 hours, 5 minutes, and flood for 5 hours, 20 minutes. It should be noted that the data used to compile the USC&GS tables are based on near surface observations, made during periods of normal river discharge, and therefore do not reflect meteorological effects. The predominance of ebb flow over flood flow will decrease with decreasing river discharge.

Within the estuary proper, the salinity decreases in a more or less uniform manner from the mouth toward the head, and at any location increases with depth. Superimposed upon the oscillatory tide, there is a net non-tidal circulation in which the upper, less saline layers of water move seaward, while the deeper, more saline layers of water move up the estuary. The net non-tidal seaward-directed flow is stronger and, in the vicinity of the site, extends to greater depths on the southern side of the estuary (looking downstream) than on the northern side. At times, the boundary between these two counterflows becomes strongly sloped so that the seaward flow extends to all depths on the south side of the estuary, and the flow directed up the estuary occurs from bottom to surface on the north side of the estuary.

The volume rate of flow associated with this net non-tidal circulation pattern, while small compared to the oscillatory tidal flows, is several-fold larger than the volume rate of river discharge. In general, the higher the salinity, the larger the ratio of the volume rate of seaward flow in the surface layers to the fresh water discharge. Consequently, since the salinity at any given location increases with decreasing river discharge, the volume rate of flow associated with the net non-tidal circulation does not decrease directly with respect to the river discharge.

There are no known or planned river control structures on the James River. Several small impoundments on tributaries in the upper reaches of the River do exist; however, their size and location would preclude any effect or danger to the safety-related structures at the station.

2.3.1.2 **Floods**

2.3.1.2.1 James River Flooding

The sources of flooding in the James River at the Surry site are flood discharges due to watershed runoff and surge due to severe storms.

As described in Reference 4, river discharge data for the period 1935 to 1993 have been collected, analyzed, and presented in Table 2.3-1. Statistical analysis of these data give the results shown in Table 2.3-2 (Reference 21). Flood discharges for the various recurrence intervals for the James River near Richmond, Virginia, are given in Table 2.3-3 (References 5 & 22). Similar data for the James River at the Surry site are given in Table 2.3-4 (References 6 & 23).

The peak flood discharge at Richmond, Virginia, during the period from 1935 to 1993 occurred in June 1972 due to the excessive rainfall during Hurricane Agnes. Flood levels reported for Richmond were 4 to 5 feet higher than those recorded during the previous flood of record. However, due to the wide flood plain at the site, the rise above normal water levels was relatively minor even during this severe flood.

It is highly unlikely that the formation of ice on the James River would obstruct the flow and cause flooding, due to the salinity of the river below the site. Thus, ice flooding is precluded as a source of flooding at the site.

An analysis of the probable rise in mean water level at the site associated with the flood discharges indicates that even for a flood discharge recurrence interval of only once in 50 years, the water level at the site would rise no more than 1 foot above normal mean river level, if not accompanied by unusual meteorological tides.

2.3.1.2.2 Hurricane Flooding

The site is located approximately 32 nautical miles upstream of the confluence of the James and York Rivers and approximately 40 nautical miles from the mouth of the Chesapeake Bay where it enters the Atlantic Ocean.

Table 2.3-5 shows the estimated tidal recurrence interval at Old Point Comfort, near the mouth of the James River. Based on a review of data compiled since 1971, there were no significant high-water levels due to storm surge in this area. The two most severe storms, Hurricane Agnes in 1972 and Hurricane David in 1979, had both been classified tropical storms by the time they reached Virginia. Neither of these two hurricanes produced a large storm surge at the Virginia coast. The highest water level recorded at Norfolk, Virginia, in 100 years of record occurred in August 1933 and reached 8.6 feet mean sea level (MSL).

The probable maximum hurricane (PMH) was chosen as the most severe meteorological event at the Surry site. The characteristics of a probable maximum hurricane at latitude 37 as shown in Reference 9, are:

Central pressure index	26.97 in. Hg
Radius of maximum winds	35 nautical miles
Forward speed of translation	22 knots
Maximum wind speed	135.4 mph

Open coast surge during the PMH was calculated at the entrance to the Chesapeake Bay using methods based on the Bathystropic Storm Tide theory as described in References 7 and 8. Theoretically, the highest open coast stillwater level consists of five components:

1. The highest astronomical tide.
2. An initial rise to account for short period anomalies.
3. The rise due to atmospheric pressure reduction.
4. The surge generated by the wind component acting perpendicular to the ocean bottom contours.
5. The surge generated by the wind component acting parallel to the ocean bottom contours.

Actual computation of the open coast surge was accomplished using two digital computer programs. The first program utilizes functions of wind speed, wind vector, and radial distance along the design axis and the traverse to compute the onshore and alongshore wind stress components, the rise in water level due to atmospheric pressure reduction for each time period at the beginning and end of each reach, and the average wind stress coefficient for each reach. The second program utilizes the output from the first program and the offshore bottom profile to compute the onshore and alongshore components of the open coast surge. The isovel field for probable maximum hurricane winds is shown in Figure 2.3-1.

The input data for the first program are shown in Figures 2.3-2 through 2.3-4. The Van Dorn wind stress coefficient was increased by 10%. The bottom friction factor used in the second program was calculated using the following equation, taken from Reference 8:

$$K = \frac{4.58 \times 10^{-6} \times W^{1.85}}{S^{1.3}}$$

where:

W = shelf width, nautical miles

S = shelf slope, minutes

For this case, the bottom friction factor was computed to be 0.00355.

The offshore bottom profile used in the second program is shown in Figure 2.3-5.

Table 2.3-6 lists components of the highest stillwater level at the open coast for the probable maximum hurricane. Once the open coast stillwater level was determined, the storm surge was routed through the Chesapeake Bay and up the James River to the power station using the methods presented in Reference 9.

The mathematical model presented in Reference 10 consists of the one-dimensional continuity and momentum equations applicable to variable area estuaries, embayments, or sea-level canals. The equations are solved simultaneously by means of an explicit finite-difference scheme to yield values of tidal elevation and flow along the longitudinal axis of the waterway. The model takes into account the effects of wind stress, river inflow, ocean tidal hydrography and non-conveyance river water storage.

The entire James River from the river mouth at Chesapeake Bay to the head of tide at Richmond, Virginia, was considered in the model. The first 75 miles of the river reach from the river mouth was divided into 25-mile segments. An adequate storage area was provided in the model to account for the total tidal area of the remaining upstream river reach.

The model was first calibrated and verified with mean tide and spring tide elevations along the James River based on Tide Tables and Nautical Charts published by the National Ocean Service (References 11 & 12, respectively). The Manning's roughness coefficients ranged from 0.018 to 0.033 for the river reaches depending on the depth and river bottom and overbank characteristics. Good agreements between the recorded tide levels and model results at various locations along the James River were found. The model was then used for storm surge routing by applying the open coast PMH storm surge hydrography at the river mouth. In addition, a conservative average wind speed of 91 mph along the PMH maximum wind axis covering the entire river reach was used to account for wind setup along the river.

The storm surge hydrography based on the mean sea level (MSL) datum at Surry Power Station and calculated in the manner described above, is shown in Figure 2.3-6. Also shown in the same figure is the wind speed versus time. For comparison purposes, the open coast storm surge which was transposed to the mouth of the James River without attenuation is shown in Figure 2.3-7. The PMH stillwater level at the Surry Station river intake is 22.7 feet (Reference 17) MSL. This surge level will result in reduced flow rates, due to reduced differential level driving head, in the gravity flow service water system. This is discussed in Section 9.9.1.3.

The size, period, and length of waves impinging on the east end of the site associated with the probable maximum hurricane were calculated using methods in Reference 13. These same methods were used to calculate run-up on slopes and the emergency pump house.

The maximum calculated wind speed acting over the 3-nautical-mile fetch affecting the station was 120.5 mph. The average depth of the fetch was 23 feet, plus the surge depth at the site, bringing the total depth to 46.6 feet.

Using Figure 1-28 and Equation 1-27 of Reference 13, these factors produced waves at the east end of the site with the following characteristics:

Wave height	9.7 ft
Wave length	159.0 ft
Period	5.6 sec

Using Figure 3-12 of Reference 13, assuming an average slope of bank of 1V to 5H, runup at the site was 8.24 feet for smooth slopes and 3.60 feet for rubble slopes. Since the slopes consist of material between the roughness of smooth and rubble slopes, these values were averaged, yielding a runup on slopes at the site of 5.9 feet. Consequently, the maximum runup elevation is approximately 28.6 feet MSL (22.7 feet MSL stillwater level at the site, plus 5.9-foot runup).

The maximum wind speed at the site was assumed to be 120.5 mph from the east. With the wind oriented in this direction, there would be no wave runup on the west side of the site. Waves would be generated and move in a westerly direction, impinging on the opposite shore.

In order to postulate waves on the west side of the site, it was assumed that waves would reflect off the opposite river bank and return to the west side of the site unattenuated. Wave runup elevations calculated in this manner will exceed those that can be reasonably expected at the west side of the site.

The average fetch was calculated in the manner described in Section 1.233b, Reference 13, and was found to be 3.2 nautical miles. The average depth of the river to the west of the site is 12.0 feet. When the river depth is added to the surge, the total water depth on the west side of the site is approximately 35 feet.

Using the methods outlined in Reference 13 and the above-mentioned data, wind-generated wave runup elevation was calculated for the west side of the site. The generated waves, impinging on the shoreline near Jamestown Island, possessed the following characteristics:

Wave height	8.5 ft
Wave length	171.0 ft
Period	6.2 sec

Assuming the shoreline around Jamestown Island approximates a smooth beach with a 10-degree slope, Reference 14 gives a reflection coefficient of 0.15 for wave H/L = 0.05. Trees and brush in the area will tend to further reduce this factor. Using this factor, the reflected wave height was calculated to be 1.3 feet. The unattenuated reflection of these waves was applied to the shore line on the west side of the station site.

Using Figure 3-12 of Reference 13, assuming the slopes in the area of the station discharge are approximately 1V to 2H, runup of waves on the west side of the site was calculated to be 1.3 feet above stillwater level in the vicinity of the discharge channel. The rock groins extending into the river and the topography between the river and the station will tend to minimize this calculated runup.

Maximum runup elevation for the west side of the site is 24.0 feet MSL. Critical equipment in this area is protected against flooding to Elevation 26.5 feet. The station grade of 26.5 feet MSL will accommodate a runup above stillwater level of 3.5 feet. In order to generate reflected waves of this magnitude, the reflection coefficient would have to be on the order of 0.4.

As shown in Reference Drawings 1 and 2, the emergency service water pumping equipment is housed in a reinforced-concrete structure above the deck of the circulating water intake structure. The floor and walls of the emergency pump room are watertight. A procedure requires the pump room entrance door to have a seal plate installed to limit water ingress into the pump house as discussed below before the arrival of the PMH to prevent inundation. Wave runup on the front of the structure is estimated to be well below the roof elevation of the structure (33.5 feet), therefore overtopping will not occur.

Breaking waves during the probable maximum hurricane could impinge on the superstructure of the emergency service water pump house, which is located on the deck of the intake structure. Using Minikin's method, as outlined on page 255 of Reference 13, the total resultant wave thrust on the wall is calculated to be approximately 29.3 kips/linear foot (Reference 19) acting at Elevation 22.7 feet MSL. The highly reinforced wall of the emergency service water pump house can withstand this loading.

The possibility of the river level being depressed below the suction level of the emergency service water pumps is extremely remote. The storm required to cause such a condition probably would be of the same magnitude as the probable maximum hurricane, and oriented in such a way that velocity components are downriver instead of upriver. For this to occur, the storm center must pass north of the river, and thus considerable filling by the storm would occur. Measurements of the probable maximum hurricane wind field indicate that downriver wind components could exist for about 24 hours, and these components would vary between zero and a maximum and back to zero during the period. Thus, it is safe to say that the suction of the pumps would not be exposed for more than 24 hours.

The emergency service water pump diesels are protected against flooding in the remotely possible event of a probable maximum hurricane.

The maximum stillwater level at the screen well is calculated to be Elevation 22.7 feet MSL. The sill of the pump room door and the air intake louver openings are located at

Elevation 21 ft. 2 in. MSL. The doors are equipped with removable seal plates which, when installed, limit water ingress into the ESW pump house such that continued emergency service water pump operation is not jeopardized through this pathway during the design basis hurricane. The air intake louver openings are protected against flooding to Elevation 24 feet MSL by watertight wells on the inside walls of the pump house. The openings are on the side of the building away from the surge.

In the unlikely event of a hurricane of postulated probable-maximum-hurricane magnitude at the Surry Power Station, there is a possibility of waves being generated, in the fetch formed between the circulating water intake structure and the east bank of the intake canal, of sufficient height and proper direction to cause intermittent surging of water into the emergency service water pump house through the air intake louvers located on the front of the structure.

To limit a buildup of water in the emergency service water pump house that could jeopardize emergency service water diesel operation, the air intake louvers are equipped with exterior covers which, when installed, limit water ingress into the ESW pump house. The exterior covers on these louvers prevent surging water from overtopping the watertight wells.

For both ESW pump house doors and the intake louver openings, the corresponding seal plates and exterior covers are required to be installed whenever hurricane conditions exist, or are forecast to exist, which would require their use to preclude significant water ingress.

With the normal air intake louvers covered, air for operation of the diesel-driven emergency service water pumps would be provided through the dampers located in the top of the pump house structure. The position of these dampers under the exhaust hood precludes any significant water entry into the pump house from wave overtopping or runup on the structure.

The elevation of the exhaust centerline is 36 ft. 6 in. MSL. This is sufficiently above the mean sea level to prevent flooding. It is possible that occasional waves may cause splash and spray up the walls of the structure to Elevation 36.2 feet MSL. These would not affect the integrity of the screen well, as the roof is watertight and the exhaust outlet is at an elevation above all wave generated splash, spray or flow and is configured to prevent any rainwater flow into the exhaust in such an event.

A minimum freeboard of greater than 4 feet is maintained between the canal water surface and the berm at Elevation +36 during hurricane flooding of the river (see Section 10.3.4.2).

In order to determine the maximum wave runup at the west end of the high-level intake canal, the wind at the station site was directed along the length of the canal. The following values were used in calculating the maximum wave runup, as described in Reference 15:

Canal depth range	20 – 25 ft
Wind speed	120.5 mph

Effective fetch	1500 ft

The waves generated possessed the following characteristics:

Wave height	1.7 ft
Wave length	41 ft
Period	1.6 sec

Using Figure 3-12 of Reference 15 and assuming a smooth canal liner sloping 1V to 1.5H, the wave runup was calculated (Reference 18) to be 4.0 feet.

Since a minimum freeboard of greater than 4 feet is maintained during a hurricane, no overtopping is anticipated, and there will be no effect on the station.

A list of maximum-probable-flood protection levels for Class I structures is contained in Table 2.3-7.

2.3.2 Ground-Water Hydrology

The hydrologic boundaries of the site proper are the James River on the east and west, Hog Island Creek to the north, and Chippokes and Hunnicut Creeks about 1 mile to the south.

Precipitation data pertaining to the site are contained in Section 2.2. A water budget analysis indicates that, of the total precipitation, 37% runs off and the remaining 63% is lost through evapotranspiration. Low soil permeabilities preclude significant ground-water recharge from local precipitation.

The soils in the site area, as described in Section 2.4, consist of a series (50 to 80 feet thick) of lenticularly interbedded fine sands, clays, and silts. These clay and silt members are essentially impermeable, and the sand member showed field permeabilities on the order of 1×10^{-4} cm/sec. Twenty shallow wells within a 3-mile radius of the site obtain small supplies of water for domestic purposes from these sands. The closest shallow well in use is located 1.6 miles south of Unit 1 and supplies domestic water to a private residence. There is an abandoned shallow well near the south property line.

The above deposits are underlain by 240 to 270 feet of tough impermeable clay containing only occasional and limited sand members. At a depth of about 320 feet below the surface, Eocene and older sediments are encountered. The sand members of these sediments are excellent aquifers; many domestic wells and some industrial wells in the area obtain water supplies from this source. In general, yields range from 15 to 50 gpm; however, a well 799 feet deep at Bacons Castle, about 5 miles to the south, yielded under test 940 gpm with only 20.25 feet of drawdown. The closest offsite deep wells are located on the State Waterfowl Refuge, about 1 mile north of the site; and at Drewry Point, approximately 0.6 mile southwest. Both wells are approximately

340 feet deep and have a yield of about 35 gpm. The well at Drewry Point is not in full-time use, since it serves a vacation cottage.

In addition to the 340-foot deep well on the State Waterfowl Refuge, which existed prior to station construction, there are nine operating water wells on the site property, which were constructed to serve several purposes. These wells are about 400 feet deep and obtain water from the Late Cretaceous sediments. Three of these wells yield 200 gpm each and are for makeup and domestic uses at the station. A separate well with a 100-gpm pump supplies the Training Center.

The hydraulic gradient is north, east, and west toward the James River. Both the deep well at Drewry Point and the shallow well south of the site up-gradient from the site. The deep well on the State Waterfowl Refuge is down-gradient from the site; however, it is not affected by water flow from the site. Based on the results of borings, the general geology of the area and the location of the site, the coefficient of permeability of the soil mass in a horizontal direction is estimated to be several orders of magnitude greater than in the vertical direction. Water that does not enter the soil will move laterally to the east, north, or west and discharge to the James River. There is no possibility of surface or near-surface water migrating downward to enter the aquifers in strata of Eocene or older ages which supply deep wells. The results of various ground-water hydrology studies indicate that no adverse effects will result to the water resources in the region because of the operation of the station.

The monitoring of various wells is incorporated in the environmental sampling program for the station. Water quality analyses at Surry Power Station Units 1 and 2 show a chloride concentration ranging from 33 to 49 ppm. In general, the quality of water from the lower aquifers is good except very near the coast or where the potentiometric levels have dropped significantly below MSL.

Due to the isolated location of the plant site (James River on the north, east, and west sides, and a game refuge on the south side), no substantial industrial or residential development is anticipated in the immediate vicinity of the plant site. Therefore, no additional demand of a substantial nature upon the ground-water supply is expected.

2.3 REFERENCES

1. D. W. Pritchard and J. H. Carpenter, *Hydrology of the James River Estuary with Emphasis Upon the Ten-Mile Segment Centered on Hog Point, Virginia*, Virginia Electric and Power Company, 1966.
2. Virginia Electric and Power Company, Surry Power Station, Independent Spent Fuel Storage Installation, *Safety Analysis Report*, October 1982.
3. *Tidal Current Tables - Atlantic Coast of North America*, published yearly by U. S. Department of Commerce, Coast & Geodetic Survey.
4. Virginia Electric and Power Company, Surry Power Station, Units 3 and 4, *Preliminary Safety Analysis Report*, 1973.
5. State Water Control Board, Commonwealth of Virginia, *Flood Frequency Data for the James River Near Richmond, Virginia*, Gauge No. 20375, 1935-1979.
6. *Magnitude and Frequency of Floods in the United States*, U. S. Geological Survey Water Supply Paper 1673.
7. C. L. Bretschneider and J. I. Collins, *Prediction of Hurricane Surge, and Investigation for Corpus Christi Texas, and Vicinity*, NESCO Technical Report No. SN-120, prepared by National Engineering Science Co. for U. S. Army Engineer District, Galveston, Texas, 1963.
8. George Marinos and Jerry W. Woodward, "Estimation of Hurricane Surge Hydrographs," *Journal of Waterways and Harbors Division*, ASCE, Vol. 94, No. WW2, May 1968, pp. 189-215.
9. Hydrometeorological Branch, U.S. Weather Bureau, *Hurricane, Atlantic and Gulf Coasts of the United States*, Interim Report, HUR 7-97, May 1968.
10. .Committee on Tidal Hydraulics, U.S. Army Corps of Engineers, *The Computation of Tides and Currents in Estuaries and Canals*, Technical Bulletin No. 16, June 1973.
11. U.S. Department of Commerce, National Oceanic Atmospheric Administration, National Ocean Service, *Tide Tables, East Coast of North and South America,* Yearly Publication.
12. U.S. Department of Commerce, National Oceanic Atmospheric Administration, National Ocean Service, Nautical Charts, United States-East Coast, Virginia-Chesapeake Bay, N. 12222, *Cape Charles to Norfolk Harbor*; No. 12248, James River, *Newport News to Jamestown Island*; No. 12251, James River, *Jordan Point to Richmond*.
13. U.S. Army Coastal Engineering Research Center, U.S. Army Corps of Engineers, *Shore Protection, Planning and Design, Technical Report No. 4*, U.S. Government Printing Office, Washington D.C., 1966
14. John J. Healy, "Wave Damping Effect on Beaches," *Proceedings, Minnesota International Hydraulics Convention*, Minneapolis, Minn., August 1953, pp. 213-220.

15. U.S. Army Coastal Engineering Research Center, U.S. Army Corps of Engineers, *Shore Protection Manual, Vol. 1.* U. S. Government Printing Office, Washington, D. C., 1984.

16. Stone & Webster Engineering Corporation Calculation, Probable Maximum Hurricane Open Coastal Surge 1493780 ENV-1 Rev. 0.

17. Stone & Webster Engineering Corporation Calculation, Probable Maximum Stillwater Level at Surry Site 1493780 ENV-2 Rev. 0.

18. Stone & Webster Engineering Corporation Calculation, Intake Canal Wave Runup for Surry Power Station 1493780 ENV-3 Rev. 1f

19. Virginia Power Calculation, CE-1062, Rev. 0, Surry Power Station Intake Structure Emergency Service Water Pump House Wave Thrust.

20. Virginia Power Calculation, CE-1229, Rev. 0, Surry UFSAR Update Table 2.3-1.

21. Virginia Power Calculation, CE-1230, Rev. 0, Surry UFSAR Update Table 2.3-2.

22. Virginia Power Calculation, CE-1233, Rev. 0, Surry UFSAR Update Table 2.3-3.

23. Virginia Power Calculation, CE-1234, Rev. 0, Surry UFSAR Update Table 2.3-4.

24. Virginia Power Letter to the State Dept. of Health, *Amendments to the Waterworks Operation Permit No. 3181800-Surry Power Station,* April 12, 1989.

2.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-55A	Arrangement: Intake Structure, Sheet 1, Unit 1
2.	11448-FM-55B	Arrangement: Intake Structure, Sheet 2, Unit 1

Table 2.3-1
MEAN MONTHLY DISCHARGE IN CFS - JAMES RIVER AT STATION SITE
FOR WATER YEARS 1935 THROUGH 1993
(I.E., OCTOBER 1934 THROUGH SEPTEMBER 1993)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Year (Avg)
1935	5191	5011	20,951	22,488	14,827	20,490	32,045	8304	7830	6402	5298	19,092	13,965
1936	3145	8324	10,336	39,778	25,806	34,620	20,767	6702	4671	2849	3154	2157	13,504
1937	5711	2765	9137	36,185	19,862	10,693	27,926	13,040	6674	5289	9281	10,836	13,331
1938	24,819	11,887	8764	12,364	9991	13,118	9179	6437	15,797	17,190	12,997	3581	12,217
1939	2914	4934	9071	8997	26,181	19,751	10,359	5953	4666	7200	9128	3005	9247
1940	3096	4911	9552	5544	18,319	9215	18,959	10,018	16,688	7203	34,397	7616	11,559
1941	3447	7722	7832	11,332	6491	9135	22,105	3919	3527	8708	1971	1258	6537
1942	857	1415	3828	4510	6329	9306	5227	13,840	8358	3896	15,167	4836	6501
1943	18,256	7319	12,771	14,106	21,118	17,614	14,073	11,788	7860	6649	2073	1508	11,221
1944	1476	2971	2659	6547	10,068	25,264	14,366	9823	3221	2312	2972	18,310	8053
1945	7251	4645	9886	13,750	12,804	12,297	8909	10,432	4178	10,654	4616	12,058	9280
1946	4294	5330	14,988	19,225	18,498	13,666	10,892	19,707	8209	6974	3846	2744	10,676
1947	2890	3455	4224	17,046	6241	13,376	13,026	6250	5107	4614	2686	3883	70,821
1948	4804	14,763	6476	9311	21,776	21,299	25,582	14,626	7700	4667	12,522	3051	2124
1949	7967	17,880	14,608	26,306	19,211	16,643	17,181	15,402	8626	13,777	9774	6254	15,814
1950	4734	11,681	8509	7858	17,805	13,292	7655	15,339	8790	6295	3895	13,268	10,012

Table 2.3-1 (CONTINUED)
MEAN MONTHLY DISCHARGE IN CFS - JAMES RIVER AT STATION SITE
FOR WATER YEARS 1935 THROUGH 1993
(I.E., OCTOBER 1934 THROUGH SEPTEMBER 1993)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Year (Avg)
1951	5073	4841	17,373	7512	17,023	15,945	21,682	8258	13,726	5190	3246	2419	10,165
1952	1827	5862	14,255	20,225	19,364	26,060	18,012	14,376	4884	4090	5870	6439	11,760
1953	2759	10,568	8983	16,907	17,642	24,795	14,829	10,005	5264	2842	1753	1618	9785
1954	1480	2207	5868	9705	7580	15,852	10,258	10,487	4231	2631	1486	954	6066
1955	5197	6395	9880	8058	12,374	25,728	12,307	5252	4733	3335	20,886	4665	9996
1956	5551	3459	2867	2992	11,632	10,921	11,667	4617	4176	3175	2259	2260	5342
1957	4270	8815	7461	7928	22,606	16,307	18,739	6662	6310	2116	1591	5050	8872
1958	4659	8761	17,261	16,549	17,213	20,480	26,168	20,890	6557	4537	6597	2652	12,675
1959	2897	2949	6019	9769	6379	8496	18,616	6081	7729	3543	3874	2791	6665
1960	10,816	9065	11,290	10,307	23,161	17,069	25,301	14,660	7471	2971	4371	6735	11,870
1961	3169	3113	3700	5533	21,475	16,639	19,391	14,579	10,072	4995	4776	4125	9194
1962	15,220	7049	20,882	19,484	15,443	32,186	22,042	9135	9339	6809	3324	2621	13,677
1963	2552	8733	5498	13,541	9076	31,513	6740	4762	4410	1690	1139	1037	7567
1964	1133	2662	4740	14,509	16,992	15,649	9580	5522	2179	2071	1421	1630	6437
1965	2874	3106	6777	11,066	18,268	18,779	11,588	6452	3123	2521	1492	1413	7223
1966	2116	1687	1592	2233	15,165	11,597	4677	9696	3184	911	1350	1857	4840

Table 2.3-1 (CONTINUED)
MEAN MONTHLY DISCHARGE IN CFS - JAMES RIVER AT STATION SITE
FOR WATER YEARS 1935 THROUGH 1993
(I.E., OCTOBER 1934 THROUGH SEPTEMBER 1993)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Year (Avg)
1967	8731	4397	6400	11,895	10,158	22,175	5977	8725	4058	2541	6881	2446	7866
1968	7454	2952	14,857	11,486	9179	14,602	6415	7101	6025	2268	1990	1091	6961
1969	2549	5139	3594	6928	8806	14,861	7618	5152	5021	8109	25,541	3777	8109
1970	7148	1048	7199	14,249	15,710	9501	14,915	7435	2309	2725	2497	1073	6986
1971	1211	11,674	6779	10,268	23,950	11,404	12,290	18,062	19,724	3884	4366	5001	10,847
1972	21,218	9641	10,143	9644	25,296	13,872	14,189	19,476	42,208	15,284	10,241	3302	16,122
1973	31,379	28,135	26,270	16,934	28,639	25,154	30,660	18,229	9386	5449	4663	2862	18,914
1974	4396	4849	25,001	21,648	13,928	14,235	15,124	11,421	7591	3878	5399	11,377	11,571
1975	2950	3321	9275	14,299	17,886	37,302	14,026	13,600	7566	13,807	5482	18,647	13,167
1976	11,034	7970	7676	23,943	13,398	9778	10,079	6000	9883	3498	1952	1904	8906
1977	21,507	8370	12,969	6552	7013	12,975	14,004	4334	2561	1616	1551	1875	7965
1978	3931	13,338	15,576	35,849	10,739	29,959	17,050	26,456	7012	4766	7425	2963	14,670
1979	2130	3156	8154	25,377	28,869	30,398	16,499	12,407	17,220	5321	5011	27,492	15,047
1980	27,223	17,836	10,691	24,528	9677	24,845	27,621	12,085	5017	3642	2272	1450	13,952
1981	2287	3067	2803	2446	6621	4459	5649	6093	7611	3899	2661	2649	4161
1982	2978	3253	6193	10,953	23,617	19,796	8420	7071	19,569	5397	5263	2427	9475

Table 2.3-1 (CONTINUED)
MEAN MONTHLY DISCHARGE IN CFS - JAMES RIVER AT STATION SITE
FOR WATER YEARS 1935 THROUGH 1993
(I.E., OCTOBER 1934 THROUGH SEPTEMBER 1993)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Year (Avg)
1983	3655	4780	13,321	6437	17,617	23,284	39,090	12,839	6860	3184	1775	1347	11,109
1984	4052	8408	18,860	12,653	27,924	30,781	32,994	16,147	6121	6035	12,157	4214	14,946
1985	3942	5073	8255	10,421	17,192	8330	6063	7088	4334	2947	11,345	3322	7308
1986	4646	42,041	12,822	6284	13,115	13,406	6195	5899	2910	1989	3571	2271	9526
1987	1670	3556	13,438	12,579	16,775	19,215	45,304	11,285	5457	2943	1397	13,332	12,158
1988	3066	6226	11,336	11,742	9654	6812	7524	10,553	4085	3174	2068	2052	6516
1989	1936	4686	4291	5775	8427	17,365	13,029	30,818	10,774	10,784	6235	12,372	10,562
1990	15,579	10,745	6852	19,947	17,792	11,915	16,503	15,785	9875	3910	3528	2205	11,181
1991	12,018	5537	9444	23,244	8575	20,720	15,237	6212	4234	6159	5106	1991	9918
1992	1879	2433	6320	8735	9355	15,890	16,694	9688	11,478	4087	3138	3244	7724
1993	2929	9352	11,782	18,211	12,877	45,418	28,277	10,497	6239	2848	2230	1695	12,709

Note: Total drainage area is 9517 square miles, of which 8395 square miles is gauged. Figures in this table include estimates of the runoff for the 1122 square miles of ungauged drainage area.

Table 2.3-2
DURATION DATA MONTHLY MEAN DISCHARGE - FRESH WATER
JAMES RIVER AT SURRY POWER STATION (1935-1993)

Mean Discharge, cfs	Percent of Months Mean Discharge is Equalled or Exceeded
857	100
2504	90
4089	75
7948	50
14,200	25
20,908	10

Mean of mean monthly discharges - 10,229 cfs

Maximum mean monthly discharge - 45,418 cfs, March 1993.

Table 2.3-3
MAGNITUDE AND FREQUENCY OF FLOOD DISCHARGES ON THE JAMES RIVER
NEAR RICHMOND, VIRGINIA (FOR THE PERIOD OF RECORD 1935 - 1993)

Recurrence Interval, years	Discharge, cfs
1.1	38,820
2	75,500
5	121,900
10	159,000
25	213,500
50	260,000
100	311,600

Table 2.3-4
MAGNITUDE AND FREQUENCY OF FLOOD DISCHARGES AT STATION SITE

Recurrence Interval, years	Ratio of Discharge to Mean Annual Flood	Discharge, cfs
1.1	0.43	47,100
2	0.85	93,300
5	1.36	150,000
10	1.77	195,000
25	2.36	260,000
50	2.85	313,000
100	3.39	373,000

Table 2.3-5
ESTIMATED TIDAL RECURRENCE INTERVAL AT OLD POINT COMFORT

Recurrence Interval, years	Maximum Tide Level, ft MSL
1	3.9
5	5.1
10	5.8
25	6.9
50	7.8
100	8.5

Table 2.3-6
COMPONENTS OF HIGHEST STILLWATER LEVEL (OPEN COAST)
FOR THE PROBABLE MAXIMUM HURRICANE

Atmospheric pressure reduction	2.02
Alongshore component	1.86
Onshore component	15.62
Open coast surge (subtotal)	19.50
Astronomical tide	3.40
Initial rise	0.50
Open coast stillwater level above mean low water	23.40
Open coast stillwater level above mean sea level	22.20

Table 2.3-7
MAXIMUM-PROBABLE-FLOOD PROTECTION LEVELS FOR CLASS I STRUCTURES

Class I Structure	Flood Protection Level, ft - MSL
Containment structure	26.5
Cable vault and cable tunnel	26.5
Pipe tunnel between containment and auxiliary building	26.5
Main steam and feedwater isolation valve cubicle	27.5
Recirculation spray and low-head safety injection pump cubicle	26.5
Safeguards ventilation room	26.5
Auxiliary building	26.5
Fuel building	26.5
Control room	27.0
Emergency switchgear and relay room	26.5
Relay room	26.5
Battery room	26.5
Air-conditioning equipment room	26.5
Reactor trip breaker cubicle	45.25
Emergency diesel-generator room	26.5
Circulating water intake structure (emergency service water pump house)	24.0
High-level intake structure	36.0
Seal pit	Not Applicable

Figure 2.3-1
ISOVEL FIELD PROBABLE MAXIMUM HURRICANE

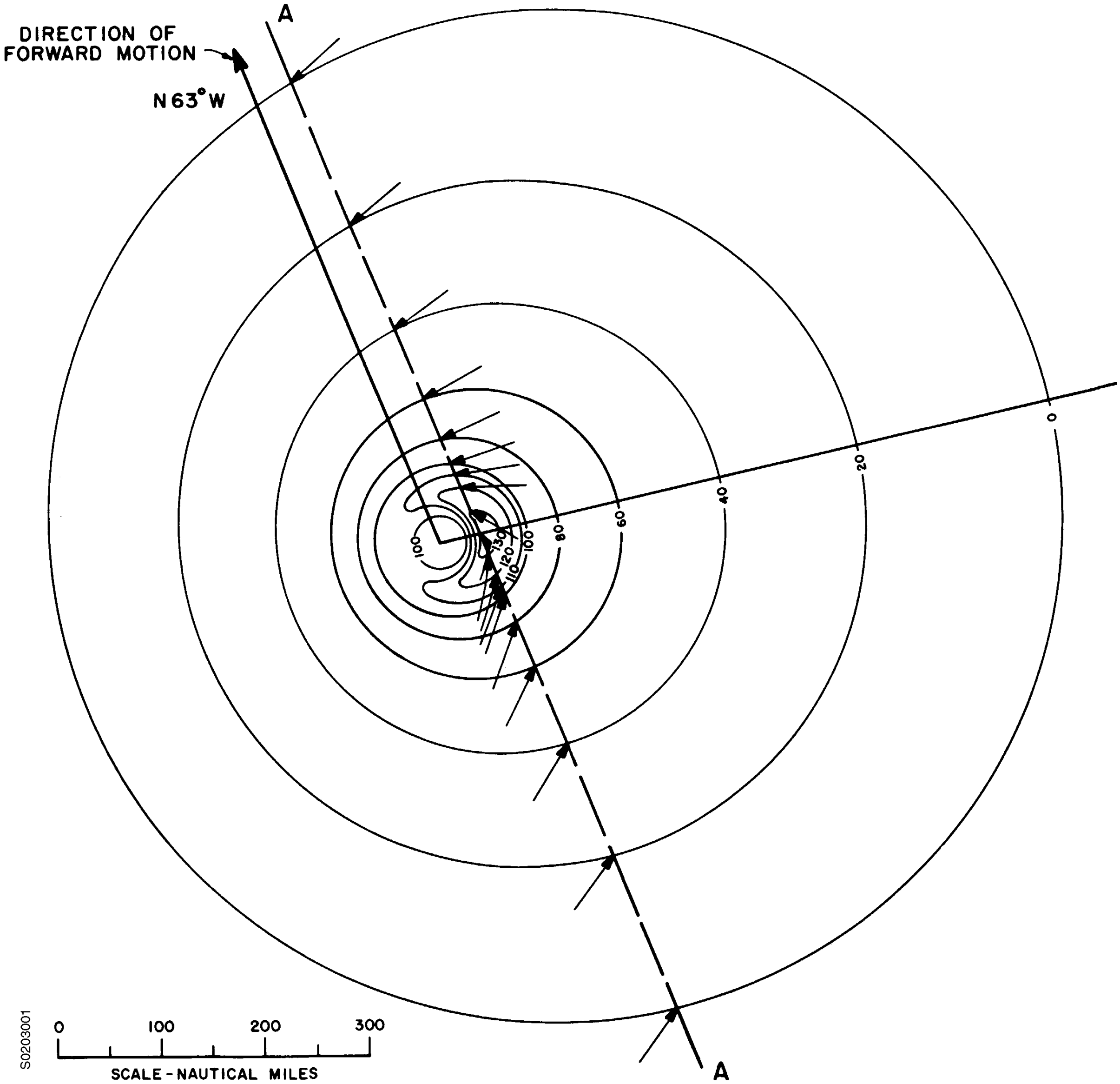


Figure 2.3-2
PROBABLE MAXIMUM HURRICANE

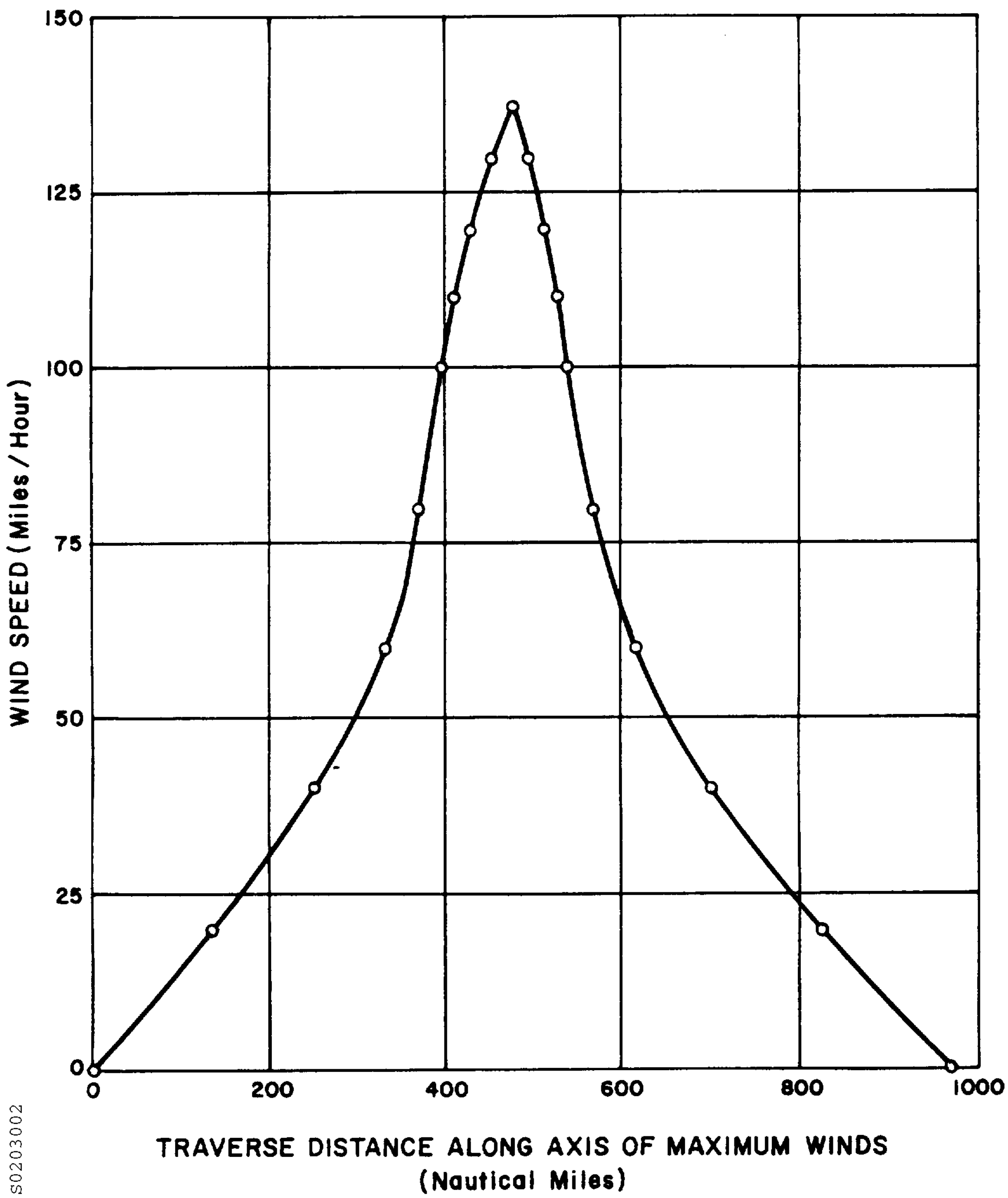


Figure 2.3-3
PROBABLE MAXIMUM HURRICANE

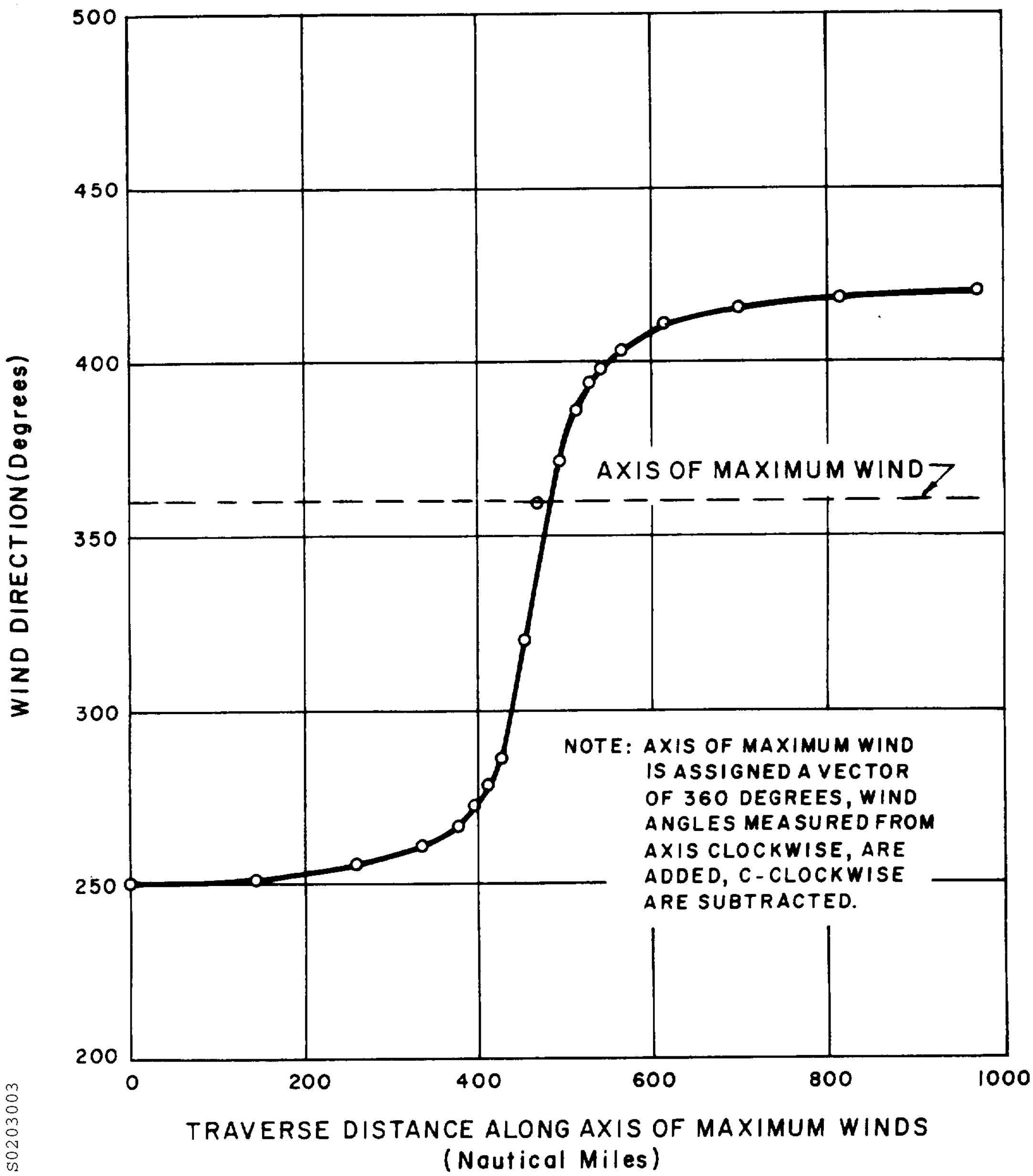


Figure 2.3-4
PROBABLE MAXIMUM HURRICANE

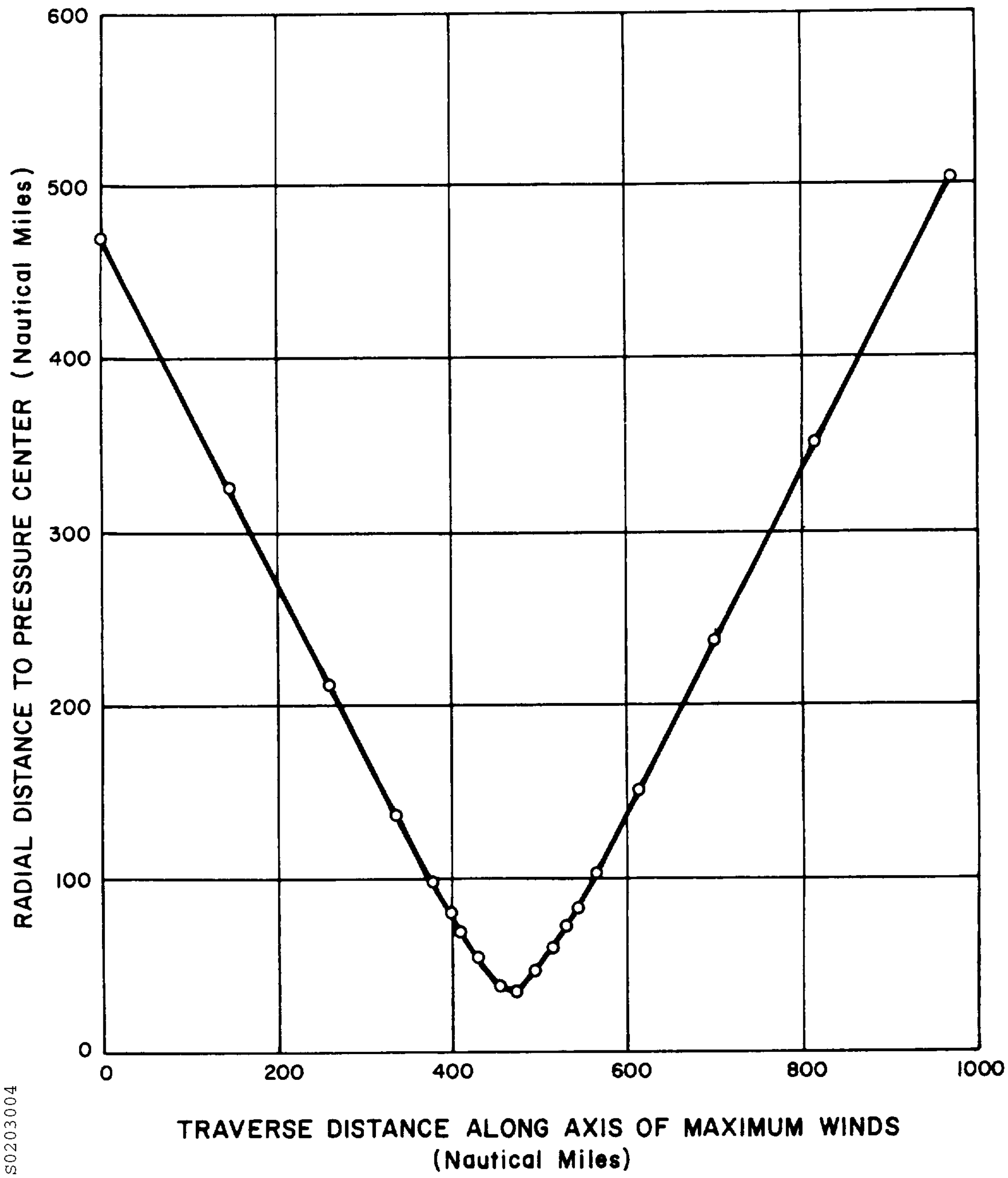


Figure 2.3-5
OFFSHORE BOTTOM PROFILE FROM CENTERLINE OF CHESAPEAKE BAY - SEAWARD ON COURSE S 63 E

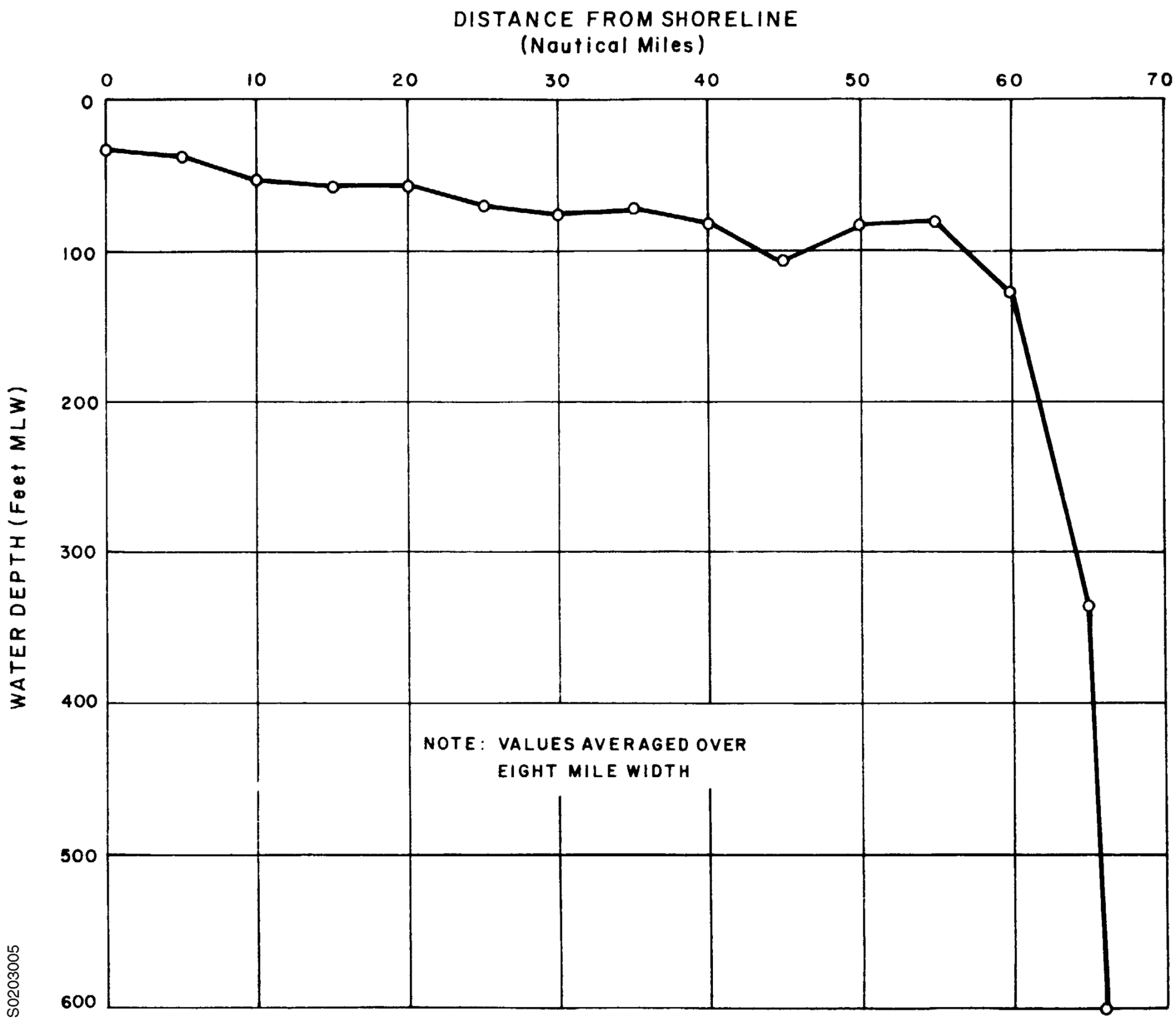
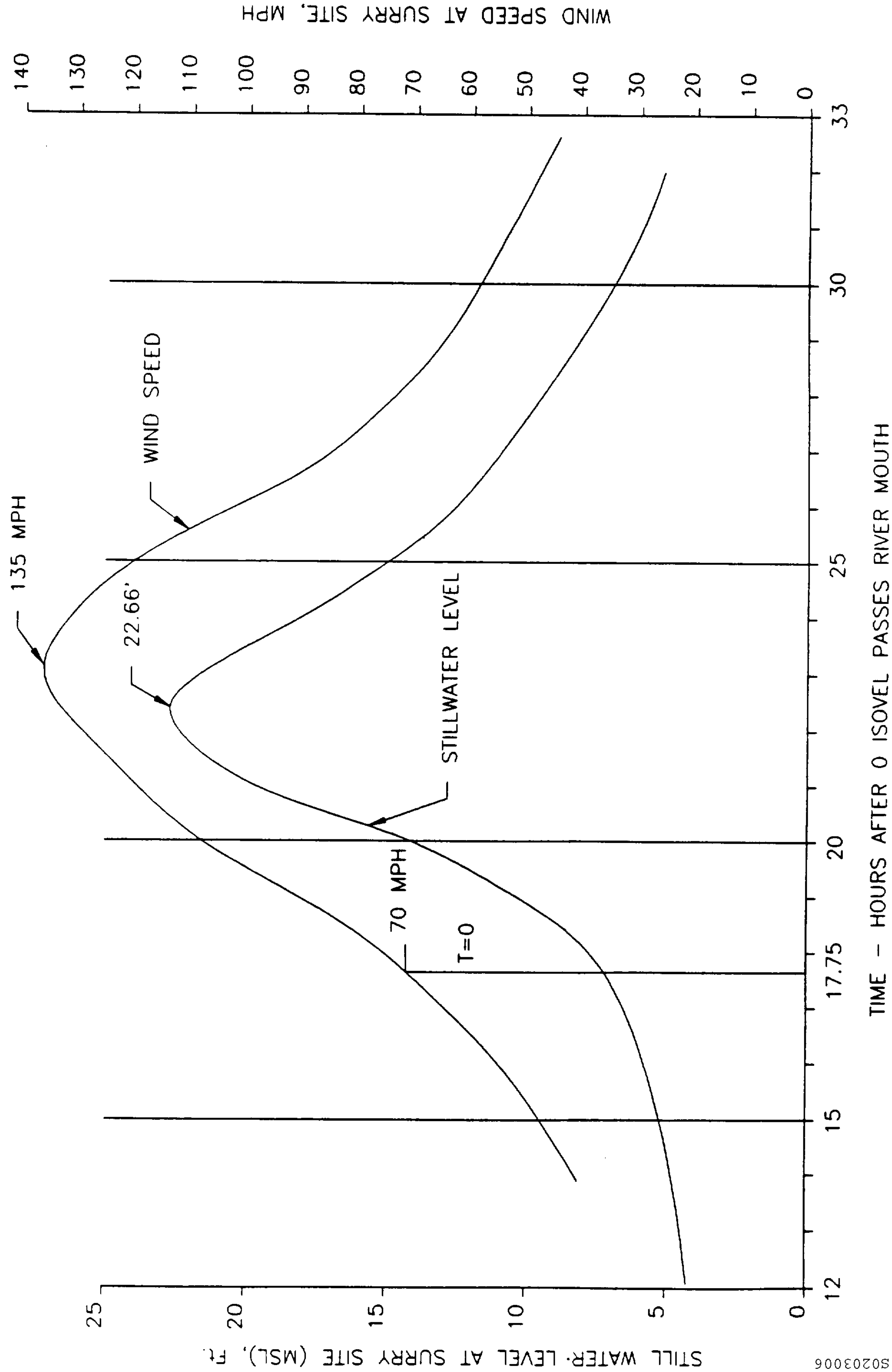


Figure 2.3-6
PMH SURGE AND WIND SPEED AT SURRY SITE



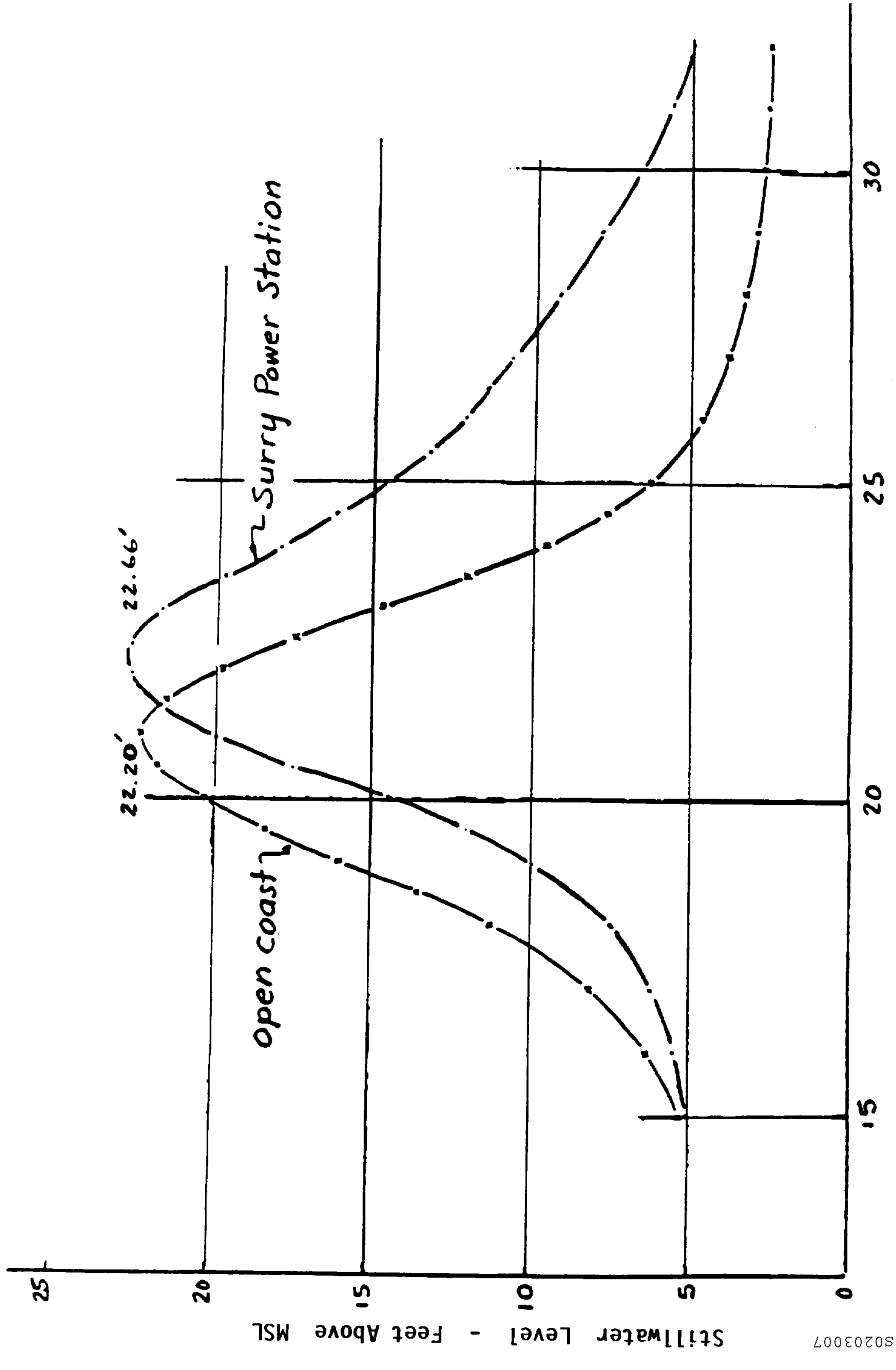


Figure 2.3-7
TIME - HOURS AFTER PMH 0 ISOVEL PASSES JAMES RIVER MOUTH SURGE HYDROGRAPHS

Figure 2.3-8
FACTORS FOR REDUCING HURRICANE WIND SPEEDS WHEN CENTER OVER LAND

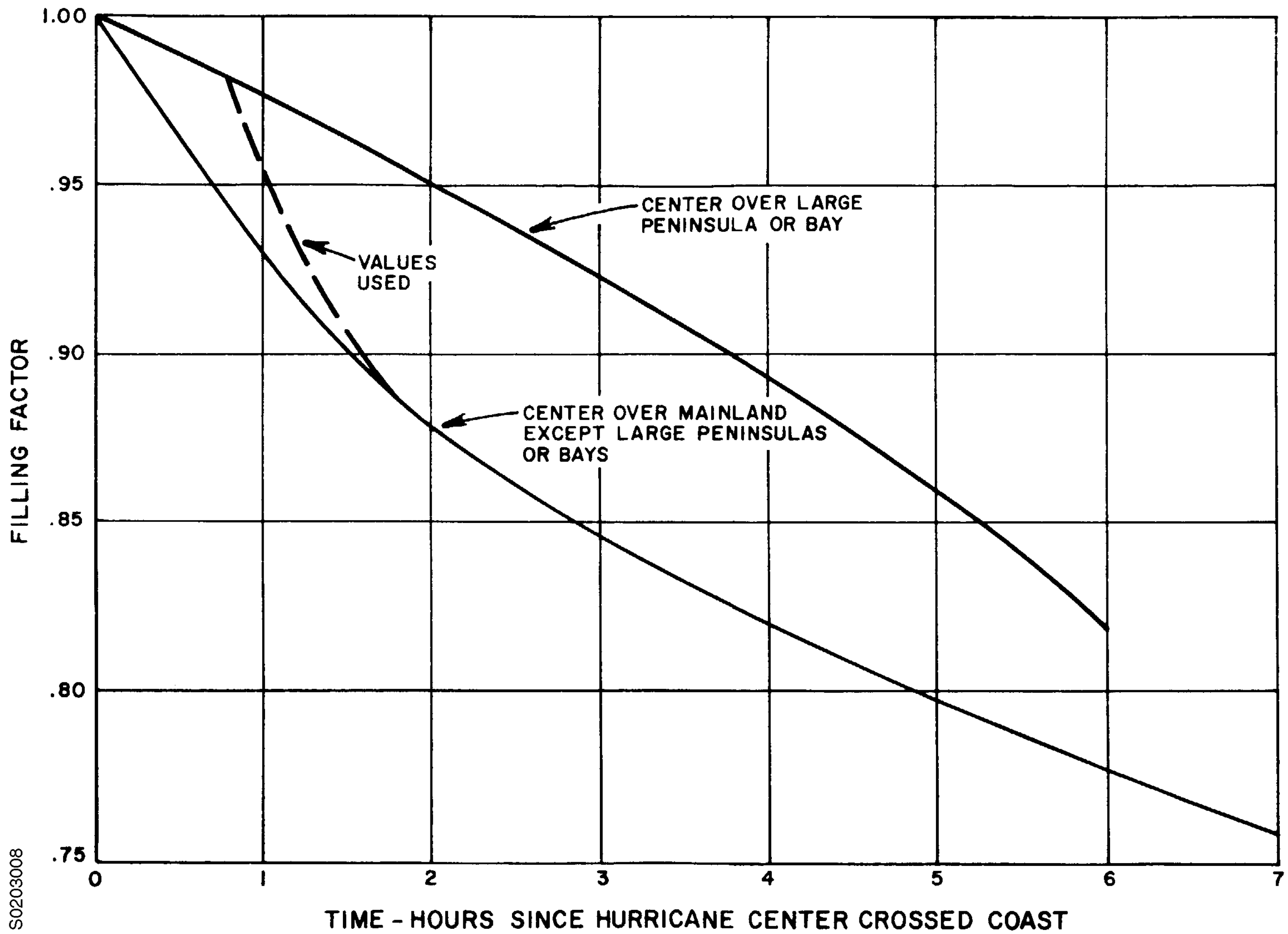
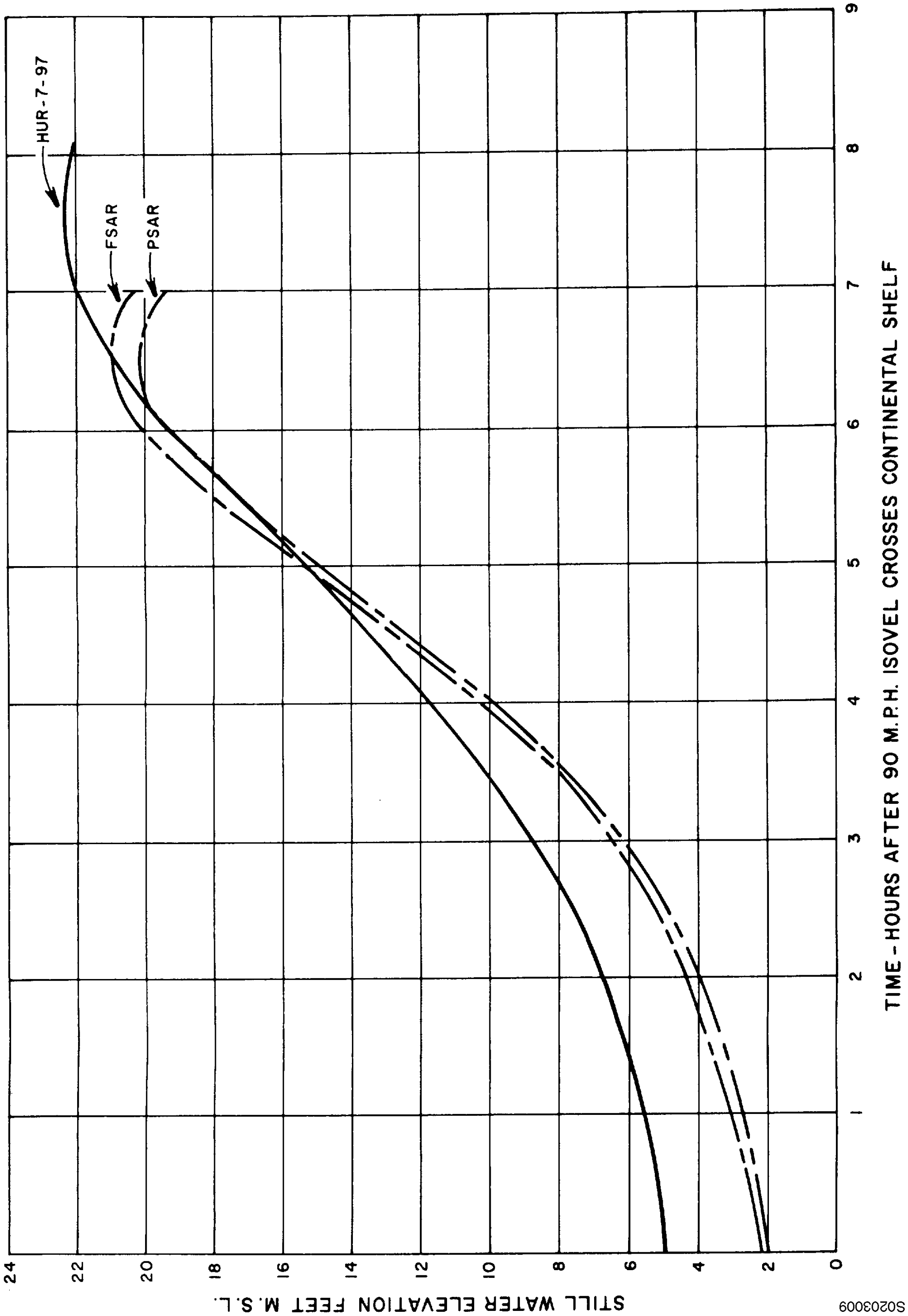


Figure 2.3-9
SURGE HYDROGRAPHS



Intentionally Blank

2.4 GEOLOGY

2.4.1 Geologic Investigations

Investigations of geologic foundation conditions at the Surry Power Station site have included the following:

1. Investigations and studies made under supervision of Dames & Moore, and reported on November 17, 1967 (Reference 1):
   a. Study and report on regional and local geology.
   b. Study of ground-water and surface hydrology.
   c. Borings - total number 55, maximum depth 200 feet.
   d. Laboratory tests of soil samples from borings to determine, under static and dynamic loads, shear strength, compressibility, permeability, and relative density of soils.
   e. Refraction seismic surveys to measure primary and shear wave velocities in near-surface soils.
   f. Micromotion studies.
2. Investigations and studies made under supervision of Stone & Webster Engineering Corporation:
   a. Ten borings by Penniman & Brown in the immediate area of the turbine building and reactor containment structures.
   b. In-place density tests of Sand A and Sand B as found during excavation of containment structure cofferdam.
   c. Lateral load test of two piles under the fuel building (report dated July 1968).
   d. Direct load test on seven piles (report dated June 28, 1967).
   e. Taking undisturbed block samples of Pleistocene clays for further testing by Hardin, and by Goldberg and Zoino.
   f. Installed system of piezometers to monitor ground-water levels in several aquifers.
3. Dr. R. V. Whitman, *Report on Foundation Dynamics for Proposed Nuclear Power Plant*, July 1967.
4. Dr. Boddy O. Hardin - Tests on undisturbed block samples of Pleistocene clays, and on a slightly disturbed sample of Miocene clay to determine static shearing strengths and shear

moduli for dynamic loadings (reported under dates of October 5, November 11, and December 1, 1967).

5. Goldberg and Zoino - October 18, 1967, and December 7, 1967, reports of tests on Pleistocene sands and undisturbed clays for determination of:

    a. Relative densities for sands.

    b. Consolidation characteristics of clays.

    c. Quick shear strength of clays.

    d. Shear strength characteristics of clays for triaxial tests with pore pressure measured, test type C. U.

Routine water samples have been taken from the James River in the area of the station where the river water is brackish. Basic sulfide and carbonate precipitation methods were used to analyze the water, instead of simply boiling the water to dryness and counting the residue. During mid-1968, a sample from Cobham Bay had a carbonate activity of 20 pCi/liter. This was greater than other samples taken from the river.

To investigate possible causes, the beaches along Cobham Bay were explored. There are numerous locations where the high banks along the river have been washed away, exposing outcroppings of the Yorktown formation which date from the Miocene Epoch (more than approximately 12 million years old). It seems wherever the outcroppings exist, a black, heavy, sand-like material is very abundant on the beaches, varying up to about 1-in. thick and several feet wide. Several samples of the black sand were taken and, in addition, numerous fossilized whale bones that were also found in the area were taken. Gamma spectral analysis by Vepco indicated a relatively high Thorium-232 content in the black sand, and a relatively high Uranium-238 content in the fossils.

In early 1969, a representative of Froehling and Robertson, Inc., of Richmond, Virginia, took six samples of the black sand and sent them to International Chemical and Nuclear Corporation for an analysis. The existence of Thorium-232 and its decay daughters was confirmed.

During the early part of 1969, a majority of the beaches along the James River were explored in an effort to determine the extent of the black sand deposits. Deposits were found scattered all along the southern shore of Cobham Bay. Locations were also found at outcroppings on Burwells Bay, south of Hog Island. In addition, deposits were found on the north shore of the James River, near Camp Wallace, which is northeast of the station site.

In June 1969, a representative of the Virginia State Radiation Health group was shown the deposits on Cobham Bay.

Since the sample of Cobham Bay water of 1968, other grab samples have varied from non-detectable limits up to 49 pCi/liter, with the majority below 10 pCi/liter.

2.4.2 Geology—Summary

2.4.2.1 Basic Geology

East of the Blue Ridge Mountains, Virginia may be divided into two broad physiographic units, the Piedmont Province and the Coastal Plain Province.

The Piedmont is essentially a bedrock plateau. Surface deposits are primarily residual soils derived from weathering of underlying bedrocks, which are basically a complex of meta-sediments of pre-Cambrian and early Paleozoic age, with some areas of sedimentary and igneous rocks of Triassic age.

The boundary between the Piedmont and Coastal Plain Provinces, termed the Fall Line, extends from New Jersey to Alabama and passes through Richmond and Petersburg. Slow regional downwarping along the axis of the Fall Line began in early Cretaceous time, about 120 million years ago, and continued through Tertiary time.

South and east of the Fall Line, the Piedmont surface was depressed to a gentle downward slope until, at Cape Henry, it is about 2800 feet below sea level. This downwarped surface formed a base on which Cretaceous and later sediments have been deposited in a general wedge-shaped mass, with individual members also being wedge-shaped and thickening toward the southeast. Based on regional data, these sediments are undeformed. They show no evidence of metamorphism and even the earliest are still essentially clays and sands. All available evidence indicates that, since early Cretaceous time, the crystalline basement beneath the Coastal Plain has been tectonically dormant. No faults are known or suspected at the site or in the vicinity of the site.

The Surry site is located on Gravel Neck, in Surry County, Virginia. The site is located in the Coastal Plain physiographic province approximately halfway between the Atlantic Ocean and the Fall Zone (see Figures 2.4-1 & 2.4-2).

In Virginia, the Coastal Plain has a stair-step character composed of a series of plains that are successively lower from west to east and are separated from one another by scarps. In the site vicinity, four plains are recognized. From the highest to the lowest they are the 120-foot plain, 90-foot plain, 70-foot plain, and 45-foot plain. Also, three prominent scarps are present. They are the Surry scarp, the Peary scarp, and the Chippokes scarp.

The surface of the Coastal Plain slopes gently in an east-to-southeast direction from about Elevation +200 at the Fall Line to sea level at the coast and thence out under the ocean. The slope is not uniform, but is characterized by essentially flat areas separated by gentle slopes of a few degrees, which are termed scarps. The average slope in the region of the site is about 1.5 ft/mile (Reference 4).

During the progressive downwarping of the crystalline basement of the Coastal Plain, various portions of the area were above, at, or below sea level, with alternating periods of marine and continental deposition occurring. A columnar geologic sections for the site area are shown on Figures 2.4-3 and 2.4-4.

The morphologic boundaries of Gravel Neck are the James River on the west, north, and east sides, and the Chippokes scarp to the south. This scarp is about 5 miles long, lies in a southeast-northwest direction, is 45 to 50 feet in height, and has a surface sloping downward toward the northeast at about 3 degrees. The site area is flat and featureless with an average Elevation of about 30 feet above mean sea level (MSL). In the immediate site area, there are no surface features indicative of actual or potential localized subsidence of landsliding. There is no history of surface mining, withdrawal of large quantities of fluids such as petroleum, or other activity by man which would cause settlement or ground disturbance. Heavy vegetation covers most of the site.

In the site area, surface deposits are sediments of the Norfolk Estuarine Formation of Pleistocene age, extending to depths of about 50 to 80 feet. The upper 20 to 35 feet of the Norfolk Formation consists of layers of brown and mottled brown sand, silty sand, and organic and inorganic silts and clays. Interspersed are thin lenses of iron-oxide cemented sands. The lower part of the formation consists of layers of gray sand, silty sand, and organic and inorganic silts and clays, many of which contain decayed vegetation and shell fragments. These most probably were deposited under estuarine, lagoonal, and swamp conditions. The Norfolk formation was deposited upon an erosional surface of the Yorktown formation during the late-Pleistocene age when the sea level rose to approximately Elevation 45 feet. At the end of the Pleistocene age the sea receded. Erosion of the Norfolk sediments is continuing today in the site area. It is accompanied by deposition of recent alluvial deposits in stream valleys, marshes, and lagoons.

The Norfolk Formation unconformably overlies the Chesapeake Group of Miocene age. Upper Miocene, Pliocene, and early Pleistocene deposits that may have existed have been removed by erosion. Within the site area, the surface of the Miocene sediments, estimated to be 240 feet thick, are found at elevations varying from -16 to -47 MSL. Consolidation tests made on samples from the Miocene deposits showed them to be overconsolidated by 4 to 5 tons/ft^2 in excess of existing overburden pressures. This suggests that from 150 feet to 200 feet of material previously lying above the present Miocene was removed by erosion before deposition of the Pleistocene deposits.

The Chesapeake Formation, of Miocene age, in the site area consists of compact, very stiff, tough clays, green to dark gray in color, with occasional compact sand and silt members. Shell fragments are common. These soils are strong and stable, with moderate to high shearing strengths. Underlying the Miocene sediments are Eocene, Paleocene, and Cretaceous sediments. These are estimated to be about 45, 55, and 800 feet thick, respectively, based on wells drilled in the general area. From seismic investigations about 2 miles southeast of the site, crystalline bedrock is estimated to be at a depth of about 1300 feet.

2.4.2.2 Geologic History

Although the complex evolutionary history of the Appalachian Highlands and that of the Coastal Plain is not completely understood, investigations by numerous geologists allow the following account of the basic geologic history of the central Appalachian region. Table 2.4-1 summarizes the major orogenic events, lists their area of influence, and comments on the character of the event.

Precambrian

Intense metamorphic deformation occurred in the Precambrian age from 1100 to 800 million years ago (Grenville orogeny). Sedimentary and igneous rocks were metamorphosed to form the metamorphic crystalline rocks now known as the basement. These basement rocks are exposed today in the Blue Ridge province and Baltimore gneiss domes.

The Grenville orogeny was followed by a period in late-Precambrian time characterized by subaerial erosion that apparently stripped away most superficial structures. This tectonically inactive period was followed by orogenic movements.

The Avalonian orogeny occurred in very late-Precambrian time, 580 to 600 million years ago. This period of deformation was marked by very large and thick accumulations of clastic sediment and volcanics accompanied, if not caused, by sharp local uplifts and downwarps. The nature of these uplifts, whether they were folds, fault blocks, or islands, remains obscure. This period of intense tectonic activity marks the beginning of the differentiation of the Appalachian region from the rest of North America.

Early-Paleozoic Era

The Avalonian orogeny was followed by the subaqueous deposition of thick carbonate and mud sequences, with some volcanics at the end of Cambrian and start of Ordovician time. In middle-Ordovician time, about 450 to 500 million years ago, the thick sequence of late-Precambrian and early-Paleozoic sediments was metamorphosed, deformed, and intruded by intense igneous activity. This period of deformation was called the Taconic orogeny and was the most intense tectonic event of the central Appalachian region.

A second orogeny, known as the Acadian orogeny, occurred during the Paleozoic age, about 360 to 400 million years ago. It was accompanied by regional metamorphism and granitic intrusion. Although very intense in the northern Appalachians, its effect in the central Appalachians is not well established.

Late Paleozoic Era

While the Piedmont and Blue Ridge provinces were undergoing metamorphism and igneous intrusion during the early- and mid-Paleozoic ages, the Valley and Ridge and Appalachian Plateau provinces were receiving sediments. At the end of the Paleozoic era, about 230 to 260 million years ago, the entire sedimentary sequence of the Valley and Ridge and Appalachian Plateau provinces were receiving sediments. At the end of the Paleozoic era, about 230 million years ago, the entire sedimentary sequence of the Valley and Ridge was folded and faulted producing the present mountainous terrain. This period of deformation is known as the Allegheny orogeny. It was long considered the main Appalachian orogeny; however, it is now evident that it was only one event at the end of a series of deformations throughout the Paleozoic. Its effect in the Piedmont and Coastal Plain must have been nominal. There is no evidence to date showing any marked tectonic activity in these provinces from the Appalachian events.

Early Mesozoic Era

The late-Triassic period, 190 to 200 million years ago, marked the last orogenic episode of the Appalachian region. Large regional arching was accompanied by development of downfaulted basins which were contemporaneously filled with Triassic continental sediments and lava flows. Accompanying the regional arching was the development of dike swarms. In the region of study, dikes trend mostly northwest which is transverse to regional structural trends. The dike activity may have lasted as late as the Jurassic period.

The eastern-most margin of the crystalline rocks of the Piedmont province was downwarped during Mesozoic time with accompanying uplift and arching of the western Piedmont and Blue Ridge provinces. The result was an accelerated erosion of the western areas and deposition of the eroded material on the downwarping eastern portion. Uplift and relative subsidence was most rapid during Cretaceous and Miocene times.

In the site area, the first sediments deposited on top of the crystalline bedrock were a mixture of terrestrial, deltaic, and shallow marine sediments of early-Cretaceous age. By late-Cretaceous time, a shallow sea covered the site area and stayed in the area until late-Miocene time. During this time interval, a thick sequence of marine sediments was deposited which are the Mattaponi, Aquia, Nanjemoy, Chickahominy, Calvert, St. Mary’s, and Yorktown formations.

The oldest unit encountered in the borings at the site is the Yorktown formation. Regionally it consists of a sand facies and silt-clay facies. The sand facies is the result of terrestrial stream deposits in a shallow marine environment. The silty and clayey sequences are the result of estuary and lagoon environments. In the borings at the site, only the silt-clay facies were encountered.

In late-Miocene and early-Pliocene time, 11 million years ago, the sea level receded which exposed the upper beds of the Yorktown formation to erosion. Extensive erosion occurred, followed by a period of deposition of the Sedley and Bacon’s Castle formation. They consist of Pliocene sediments of fluvial and estuarine origin.

During late-Pliocene and early-Pleistocene times, 2 million years ago, extensive erosion occurred which removed much, or in some places all, of the Bacon’s Castle and Sedley formations. Subsequently, the sea encroached on the land to about Elevation +100 and deposited estuarine and littoral (beach) sediments of the Windsor formation.

During mid-Pleistocene time, the sea receded in stages leaving step-like plains and scarps at each intermediate stage. Erosion was extensive and in the site area all of the Windsor formation and parts of the Yorktown formation were removed. The present valley of the James River was established during this time.

In late-Pleistocene time, the sea level rose for the last time to about Elevation +45 accompanied by the deposition of clayey sands of the Norfolk formation in marshes and nearshore marine environments.

From the end of the Pleistocene time to the present, the sea has receded and the erosion of Norfolk sediments is continuing today in the site area. It is accompanied by deposition of recent alluvial deposits in stream valleys, marshes, and lagoons.

2.4.2.3 **Structural Geology**

The site area lies on the southern flank of the Chesapeake-Delaware embayment, a depositional basin that has been downwarping and receiving sediments since late-Jurassic time, approximately 140 million years ago. Present regional subsidence in the site area has been measured to be about 1 to 5 mm per year (Reference 2). The resulting dip of the sedimentary units is oceanward, toward the east. The dip of the late Tertiary units (Yorktown) in the site area is 2 to 7 feet per mile, southeast (Reference 3).

For bedrock structural contours from the Cretaceous through the Pleistocene eras, no abrupt thickening nor asymmetric isopach contour patterns are present as would be expected for fault type subsidence (Reference 2). Rather, large gradually varying isopach patterns are evident. These may be formed by gradual regional downwarping, differential compaction, erosion or as a function of distance from the sediment source (deposition). The isopach centers vary in location with geological time and are not correlative with any localized structural effect.

Except for an area near Yorktown, Virginia, the site area and vicinity is devoid of any structural features indicative of folding or faulting. Southeast of Yorktown, Virginia, the beds of the Yorktown formation (Miocene age, 25 to 11 million years old) show a reversal of the regional dip. The beds dip 8 to 55 feet per mile, northwest. The reversal area was once believed to be of tectonic origin. However, as a result of more recent studies by Johnson, 1972 (Reference 3), the warping appears to be contemporaneous with Miocene deposition and the result of differential compaction of underlying units in response to surface loading. The northwest tilting had ceased prior to Pleistocene deposition, 2 million years ago. The overlying Pleistocene sediments show no dip reversal and conform with the regional trends.

In the immediate site area, surface inspection and subsurface investigations show no evidence of structural deformation. The borings indicate no offsets or folding of strata. There is no surface or subsurface evidence of prior landslides, cratering, or fissures that may be indicative of prior intense earthquake effects.

2.4.3 Soil Conditions

2.4.3.1 General

Original ground through the area of the station was at approximately Elevation +34, except for a few small shallow erosional depressions leading toward the river or north to the low marsh areas of the adjacent Hog Island Game Refuge.

Finished yard grade in the station area is Elevation +26.5. From ground surface to approximately Elevation -38 is a series of alternating strata of clay and sands of Pleistocene age. These lie unconformably on Miocene clays that have in their upper portion a series of thin sand lenses. These thin Miocene sand lenses were found intermittently between about Elevations -55 and -62, and were individually only a few inches to a foot or so in thickness.

The locations of borings in the station area are shown in Figure 2.4-5. Detailed subsurface profiles along two mutually perpendicular axes, one through the reactor centerline of the containment structures, and the other on a line midway between the two units, are shown in Figures 2.4-6 and 2.4-7, respectively. For convenience in descriptions and studies, the sand members shown in Figures 2.4-6 and 2.4-7 at about Elevation -5 have been called Sand A, those at about Elevation -35, Sand B, and the thin sands at about Elevation -55 in the upper portion of the Miocene clays, Sand C. Sand A was present in its natural state during the period of geological investigation, but was replaced by backfill in selected areas prior to construction.

Additional information on 1982 borings conducted in the vicinity of the Surry site can be found in Reference 2.

2.4.3.2 Pleistocene Clays

The Pleistocene clays are dark olive to dark gray, and of low to medium plasticity. Atterberg limits plot along or slightly above Casagrande's A Line, with liquid limits ranging from about 35% to 50%, and liquidity indices of about 30 to 40%. Quick shear strengths of these clays range from 1100 to 2900 lb/ft^2. These were obtained in tests on undisturbed block samples taken during excavation of the cofferdams for the reactor containment structures. Sensitivity of these clays was about 3 to 6, when sensitivity is defined as the ratio of shearing strengths in the undisturbed state to those after complete remolding, with no change in moisture. Shear moduli as determined in cyclic torsional shear tests (Reference 4) were found to be about 12,000 psi to 14,000 psi, using undisturbed samples reconsolidated to appropriate vertical effective stresses. These values agree satisfactorily with Hardin's proposed relations for computing shear moduli based on void ratio and effective stress. Damping in these tests was about 0.03 of critical at strains of about 2×10^5 radians. Consolidation tests on undisturbed samples showed preconsolidation of about 0.5 to 0.75 tons/ft^2 in excess of existing overburden.

2.4.3.3 Pleistocene Sands

Investigations of the Pleistocene sand made using borings during the initial site investigations (borings 7 through 44) were later supplemented by an additional series of borings

(45 through 50A), which were made after the station area had been excavated to about Elevation +7. A third group, designated by the suffix A or B, was then made adjoining and paralleling selected borings from the first two series. The purpose of this last series was to determine whether relatively low blow counts recorded for some of the samples taken in the sand were truly representative of conditions. Great care was taken with these last borings to ensure proper sampling techniques. The locations of all borings in the area of the structures are shown in Figure 2.4-5.

In the first series of borings, samples were taken using a 2.5-inch i.d. sampler, driven by a 300-lb weight falling 18 inches, or by hydraulic pull-down. In certain of the second series of borings, samples were taken alternatively with the above equipment and with a 1-3/8-inch i.d. sampler driven by a 140-lb weight falling 30 inches, commonly referred to as the standard penetration test.

Plotting of the results of the driving resistances against each other for the second series of borings indicated that, for soil requiring 10 blows for 12-inch penetration in the standard penetration test, the 2.5-inch sampler required from 7 to 8 blows.

In situ densities and relative densities of sand members A and B were established by direct measurements and by study of penetration resistances in borings.

Profiles of the soils as determined during the excavation of the cofferdams are shown in Figures 2.4-6 and 2.4-7. The two significant sand strata, A and B, are considered individually. Their density has been investigated by direct measurement of in situ density, as found in tests made as the cofferdams were excavated, and measurement of the density of undisturbed boring samples. The locations and elevations are shown in Figure 2.4-8. Shown also in this figure are locations where undisturbed block samples of the Pleistocene clays were recovered. Results of these in-place density tests are shown in Table 2.4-2, separated into Sand A and Sand B. In making these in situ tests, an attempt was made to select the cleaner sand members by visual examination. Despite this precaution, silty sands and some having significant dry strengths were included, especially in Sand B, which contained more silt and clay than did Sand A. Table 2.4-3 shows gradings for samples taken at 12-inch intervals vertically in Sand B between Elevations -26.5 and -36.5. It should be noted that only two of the samples were clean, and these were taken from a well-graded thin-gravel member.

Maximum densities obtained in the modified Proctor compaction tests by vibration were determined for comparison with the in situ density for each test. Minimum densities were determined for a number of the samples, which were sufficiently clean to make the minimum density test procedure valid. Relative densities are tabulated showing the values of in situ relative density, as compared with maximum density from both vibration and compaction. These data show Sand A in situ relative densities. Relative densities for Sand B were not established because of general excessive siltiness, which interfered with establishing minimum densities satisfactorily. In situ densities for these materials, in general, ranged from about 100 to 110 lb/ft^3, with one sample showing an in-place density of 94.2 lb/ft^3, equivalent to 88% of the maximum modified Proctor density for that soil.

Also shown in Table 2.4-2 are relative densities obtained by Dames & Moore from tests made on undisturbed samples of these soils. Undisturbed samples for this purpose were taken using the Dames & Moore thin-wall sampler, or with a Pitcher sampler forced down by hydraulic pressure. Their results are in close agreement with the in situ tests.

The soil within the cofferdams was excavated using a 3-yard clam shell bucket dropped freely. In both Sand A and Sand B, because of the projection of the wales, excavation by this equipment left an annulus of soil approximately 3 feet wide against the sheeting. This soil annulus stood intact with vertical faces of 12 to 16 feet in height until removed later.

Table 2.4-4 shows the blow counts for all samples in the upper sand from the borings. These are arranged in two groups, Group 1 being for the initial series of borings, and Group 2 for the second series of borings made within the area excavated to Elevation +7. The table also gives the amount of overburden for each sample above the elevation of the sample at the time the boring was made. A second column of "N" values headed "Adjusted Blow Count" is shown. In this column, the blow count for the 2.5-inch sampler has been increased by the ratio of 10:8 to correlate the results using this sampler with the standard penetration tests. Table 2.4-5 shows similar data for the lower sands.

As previously noted, supplementary borings, identified by the subscript A or B, were made adjacent to a number of the earlier borings that had shown relatively low blow counts, or "N" values. These supplementary borings were made about 3 feet from the original borings, under very careful supervision and sampling techniques to ensure results free of disturbance or error. Accordingly, where supplementary borings were made, data from the initial borings were omitted as being questionable.

These data are shown graphically in Figure 2.4-9 for Sand A and in Figure 2.4-10 for Sand B. On these graphs are shown the fraction of occurrences of different values of blow count for the Group 1 borings and Group 2 borings. In Sand A, particularly, the difference between the two groups of borings is quite marked. The overburden effective stress at the level where these samples were taken was of the order of 3500 to 4000 lb/ft^2.

After the area was excavated to Elevation +7, much less energy was required to drive the sampler, as indicated by the distribution of blow counts.

Relative densities of the sands from the penetration test results have been determined using the "Average Curve" of Gibbs and Holtz (Reference 5). These data, together with the relative densities as determined from the in situ tests and undisturbed samples, are plotted in Figure 2.4-11.

These data indicate that Sand A is of variable density, ranging from sand of medium density, having a minimum relative density of about 65%, to very dense sands with relative densities in excess of 95%. Sand B is more uniform. The loosest members again are of medium density, about 65 to 70% relative density, or possibly slightly greater, with the majority of the sand in the dense condition at about 80% or greater relative density. Also, it should be noted that Sand B contains considerable silt and clay, and is thus less susceptible to liquefaction than clean sands would be.

2.4.3.4 **Miocene Deposits**

Underlying Sand B is the Miocene clay. The contact is an unconformity, i.e., erosional surface, varying from about Elevation -34 to Elevation -40 in the station area. The Miocene clays are very stiff, and of a gray-green color. Boring 15, which was sampled continuously below Elevation -5, showed several thin sand members varying from a few inches to about a foot in thickness individually, and having a total thickness of about 4 or 5 feet below about Elevation -55. These sand members have been termed Sand C. This is a glauconitic, clayey, silty sand. It was definitely identified only in Boring 15, but sandy members were noted at about the same elevation in several of the other borings. It is believed to be of limited lateral extent.

The Miocene clay is heavily overconsolidated. Preconsolidation pressures as determined in consolidation tests are plotted in Figure 2.4-12. These show overconsolidation of about 4 to 5 tons/ft^2. Atterberg limits for this material plot somewhat above Casagrande's A Line in the region of low to medium plasticity. Quick shearing strengths are about 400 to 500 lb/ft^2. Shear moduli, as determined from torsional shear tests on a reconsolidated boring sample that may have been slightly disturbed, are about 16,000 psi. This is somewhat below the value computed after Hardin. Internal damping as measured in the torsional test is about 0.03 of critical at strains of about 2×10^{-5} radians.

2.4.3.5 **Site Settlement**

A site survey conducted in May 1975 indicated that site settlement was not a problem at the Surry Power Station (Reference 6). A follow-up survey program was continued over the next 2 years to further monitor site elevations. The results of the follow-up survey program are given in Table 2.4-6.

The follow-up survey program indicated that a small amount of heave had occurred in the vicinity of both containment structures; however, the differential movement between safety-related structures was below the allowable tolerance of 0.5 inches (0.042 feet). As shown by Table 2.4-6, the maximum differential movement had been about 0.2 inches (0.016 feet). Inspection of structural interfaces showed no visible evidence of differential displacements.

2.4.4 Ground-Water Level

As a portion of the original boring investigation, slotted plastic pipes were installed in a number of the borings to permit observations of ground-water levels in the area. These proved unsatisfactory. Accordingly, in September 1967, Casagrande-type piezometers were installed at five locations, as shown in Figure 2.4-5. These piezometers were installed after the start of excavation for the containment structures, and drainage incident to the construction was considered in locating the piezometers.

As previously discussed, the boring program indicated two principal sand strata under the proposed structures. Also, there is a thin sand member near the top of the Miocene clays. The piezometer program was designed to measure the water table elevations in these three strata.

There are five groups of piezometers. Groups P1 and P2 each contain three piezometers, one in Sand A and two in Sand B, with one near the top and one near the bottom. Groups P3 and P4 each contain two piezometers, one in Sand B and one in the thin stratum at about Elevation -55 in the underlying Miocene clays, Sand C. Group P5 contains two piezometers, one each in Sand A and Sand B.

All piezometers are bedded in clean sand and installed in permanent casings. Bentonite seals extend from the sand embedment up into the casings. Approximate tip elevations were selected from data obtained from nearby borings. This was refined with preliminary borings at the locations selected for each group of piezometers, and the final tip elevation adjusted as necessary to place each piezometer in the sand stratum selected for study.

Readings of the piezometers began on September 26, 1967, after they had been installed for at least a week, which provided time for stabilization. These readings were made at hourly intervals for a 24-hour period in order to include two tide cycles. No response to tides could be detected within the limits of accuracy of the read-out, which is estimated to be ±0.1 feet. Thereafter, readings on the piezometers were made once a day until October 6, 1967, when the read-out interval was changed to once a week.

On October 4, 1967, all piezometers were flushed, and the rate of fall noted. The rate of fall indicated that all piezometers were in good communication with the soils in which they were set.

Read-out of piezometers was continued at a weekly interval until June 1968, approximately 8 months, and then placed on a weekly to biweekly interval until October 1968, completing a year of observations. No significant variations were noted during this period. The range of piezometric level in the piezometers remote from the station was only about 1 foot throughout this period of observation. The highest ground-water level observed during this period in Groups P1 and P2, which are remote from the excavation, were as follows:

1. Group P-1

   Sand A +2.2 on September 26, 1968

   Sand B +2.8 on February 8, 1968

2. Group P-2

Sand A +4.3 on February 1, 1968

Sand B +3.8 on February 8, 1968

The range of fluctuation, high to low, through this period of observations was approximately as follows:

P-1-A (Sand A) 1.9 feet

P-1-C (Sand B) 2.0 feet

P-2-A (Sand A) 1.5 feet

P-2-C (Sand B) 1.6 feet

Additional piezometer data from 1967 and 1971 are shown for comparison purposes in Table 2.4-7 and Figures 2.4-14 through 2.4-19. The consistency of the readings over this period indicates that each stratum behaves as a continuous aquifer, rather than as a series of isolated lenses. Possible interconnection between Sands A and B was not established, but may exist. Should interconnection exist, communication should be small, since the vertical permeability of these sands is estimated to be about two orders of magnitude smaller than the horizontal permeability. Additional information on groundwater level at or near the Surry site can be found in References 7 and 8.

Moderate seepage occurred through the interlocks of the sheeting for the cofferdams for the containment structures. This drainage resulted in significant drawdown on the water table in Sands A and B at the cofferdam. In addition, six subsurface relief drains constructed with sand filters were provided into the Miocene clays under each containment structure. Two penetrate to Elevation -105, and four to Elevation -65. They discharge to the drainage system by means of a pervious layer provided under the containment structure. Seepage from Sand C through the cofferdam sheeting, and from under the structure, is collected in the sumps and removed by a system of permanent pumps. These pumps are set and controlled to maintain the water level around the containment structure at about Elevation -33 ±2 feet. The annular space between the cofferdam and walls of the containment structure was backfilled with select granular material that is pervious. This pervious backfill rests on pervious concrete, and is thus connected to and drained by the drainage system.

It is assumed that Sand A is continuous to the discharge canal, and thus would be exposed to inflow from the canal during high water levels in the river. The maximum flood on record in the James River is 234,000 cfs. This corresponds to about the flow in the average spring tide cycle at the site. A flood of this magnitude would raise the river water level at the site about 1 foot above normal level. As the installed piezometers indicated no response to tides, no response would be expected to a 1-foot increase in river water level.

The maximum recorded water level near the site was Elevation +7.7, which occurred as a hurricane surge in August 1933. Hurricane surges are of very short duration; the entire cycle from normal water level to maximum level to return to normal occurs in 24 hours or less.

The sharp gradient observed in the piezometric level in Sand A, proceeding away from the containment cofferdam observed during the construction period, indicates that short-duration exposure of Sand A to a high water level in the discharge canal would not affect the piezometric level in Sand A at the location of the structures because of the low permeability of the soils and the distance of the station site from the river and discharge canal.

Precipitation for the 12 months, September 1966 through August 1967, for several stations, is shown in Figure 2.4-20. It should be noted that total precipitation in this 12-month period was approximately equal to the mean precipitation for the area. Precipitation for the months of July and August was greater than normal, August having approximately double the recorded average for the month. Considering the geography of the site and the character of the near-surface deposits, it is reasonable to assume that precipitation in the immediate months preceding would have the greatest effect on water table conditions.

As indicated previously, the drainage system of the containment cofferdams is permanent. Observations showed piezometric levels during construction of about Elevation -5 in Sand A, and about Elevation -10 in Sand B near the containment structure cofferdams. Values approximating these levels may be anticipated during operations. However, piezometric levels in these sands have been assumed at Elevation +5 in studies of liquefaction potential. This is above values recorded remote from the units and is considered conservative.

2.4.5 Liquefaction Potential

2.4.5.1 Summary

Analyses of the potential for liquefaction of the sand underlying the Surry Power Station, based on piezometric data for the site, prove that liquefaction would not occur in any stratum for an earthquake having a maximum ground acceleration of 0.15g, the design-basis earthquake.

If the maximum earthquake acceleration were increased to a hypothetical value of 0.25g, the analyses indicate acceptable factors of safety against liquefaction, based on maintaining, in the future, present piezometric levels by means of the drainage provided. Even if it were assumed that drainage of Sand A or Sand B ceased to function and piezometric levels rose to a general site area value of Elevation +5, the analyses, which are based on conservative assumptions, give factors of safety greater than unity for the loosest zones found in either Sand A or Sand B. This would indicate that even momentary liquefaction will not occur in either sand. Since, however, Sand A immediately underlies the foundation mat of the auxiliary building and control area, where even local distortion might be significant, Sand A was removed from under the fuel building, auxiliary building, and control area, and replaced by dense-graded granular fill placed and compacted to such density equal to or exceeding 95% of that obtained in the Modified

Density Test-ASTM-1557-66. This effectively precludes any possibility of liquefaction in Sand A at any point under these structures. Since liquefaction of small pockets of Sand B could not result in any distortion of these auxiliary structures, Sand B was not replaced beneath the foundations of these structures.

The thin sand members in the upper portion of the Miocene deposits are permanently drained to the sump pumps exterior to the containment structure. This sand would not be subject to liquefaction under a hypothetical earthquake of 0.25g because of the weight of the overburden and the prevailing drainage, which results in depressed piezometric levels. The remaining strata are clays of types that are not subject to liquefaction.

Liquefaction will not occur at any location under yard areas adjacent to station structures, since the weight of the overburden is sufficient to preclude it.

2.4.5.2 **Analysis**

Stratigraphy, soil properties, and piezometric data for the site have been discussed in detail in Sections 2.4.3 and 2.4.4. Seven dynamic triaxial tests have been performed upon samples of these sands at their in situ densities. In none of the tests was a sudden, complete liquefaction experienced; rather, once the applied cyclic shear loads were made large enough, there was only a gradual increase in strain during each cycle of loading. Such behavior is consistent with the in situ relative densities and with the large content of fines in the sands, especially in Sand B. This program of dynamic triaxial tests is discussed in Reference 9. The procedures followed in the analysis to determine the factor of safety against liquefaction are given in Reference 10.

As discussed in Section 2.4.4, piezometric levels under the structures will be depressed below the general area piezometric level of Elevation +5 because of permanent drainage facilities provided within the cofferdams of the containment structures. Analysis indicates that, under any of the several structures considered, the highest future piezometric pressure level in Sand B will be at or below about Elevation -7. In the unlikely event that these drainage systems ceased to function, ground-water levels could rise to the general area piezometer level of Elevation +5.0. Analyses of liquefaction potential have been made for two different assumptions:

1. Ground-water level at Elevation -7.
2. Ground-water level at Elevation +5.

The factor of safety against liquefaction at any given depth within a soil can be estimated by comparing the average peak shear stress caused by an earthquake to the shear stresses required to cause liquefaction. The procedures used for estimating these two quantities have been verified by the experiences at Niigata and Anchorage.

Reference 11 presents curves used to establish the shear stress required to cause liquefaction. These curves were derived from tests upon a sand that is especially susceptible to liquefaction. Tests upon sands from Surry demonstrate that these curves give a conservative estimate for the resistance to liquefaction by the sands at Surry.

Reference 12 describes the basis for estimating the shear stresses caused by an earthquake. These estimates are based upon dynamic analyses giving the shear stresses developed near ground surface during actual earthquakes.

Typical calculations for safety factors are also presented in Reference 13. The safety factors presented are conservative, since:

1. A conservative (high) estimate has been used for the shear stresses caused by the assumed earthquake.
2. A conservative (high) estimate has been made for the number of cycles of motion during the assumed earthquake, thus leading to a conservative (low) estimate for the shear stress that will cause liquefaction.
3. The stresses required to cause liquefaction have been estimated using curves applicable to a sand (Sacramento River No. 3) that is especially susceptible to liquefaction. The characteristics of the sands at Surry indicate that they possess a greater resistance to liquefaction, especially Sand B, which is predominantly very silty, and, in places, clayey.

Factors of safety against liquefaction and cumulative strains of 5% for various structures and the several strata are tabulated in Reference 14 for 0.15g maximum ground acceleration, the design-basis earthquake, and in Tables 9.12D-l and 9.12D-2 of the FSAR (Reference 15) for an assumed hypothetical 0.25g ground acceleration.

The factor of safety against liquefaction of Sand A is of significance only for the yard areas, since this sand has been removed and replaced under the Class I structures. Analysis even for the hypothetical 0.25g acceleration shows an average factor of safety against initial liquefaction in the yard areas of 2.0 for Sand A for a ground-water table of Elevation +5. The factor of safety against the development of a cumulative strain of 5%, which may be used as a measure of the strain at which significant settlements may be expected to occur, would be about 2.1. Within isolated pockets, where the relative density may be only 60%, the safety factor against 5% strain would be about 1.6 for the conservative assumption of ground water at Elevation +5.0.

For Sand B, factors of safety at hypothetical 0.25g acceleration for average conditions at estimated future piezometer levels, considering drainage provided, would be about 1.8 under the auxiliary building for initial liquefaction, and 1.9 for 5% cumulative strain. If drainage were not considered, and a piezometric level of Elevation +5 was assumed, the values for average soil conditions for initial liquefaction would range from 1.4 under the auxiliary building to 1.8 under yard areas, and against 5% cumulative strain from 1.5 to 1.9.

Even if there were a few pockets where the relative density was only 60%, the safety factors against 5% strain would range from 1.2 to 1.5, based on the conservative assumption of a ground-water table at Elevation +5.

For Sand C, calculations indicate probable average factors of safety of about 1.9 against initial liquefaction, and 2.0 against a cumulative strain of 5% under the containment structure.

These are based on observed piezometric levels, considering the permanent drainage system. If there were isolated pockets of sand having a relative density of 60% within this member, the factor of safety would be 1.5 against a cumulative strain of 5%.

As a further check on shearing stresses, a modal dynamic analysis was made of the entire soil column using recently developed procedures by Dr. Whitman (Reference 16). For this purpose the record of the El Centro earthquake, normalized to give maximum particle velocities at the surface of about 6 in/sec and 8 in/sec, was used as input at the rock surface. Input data were normalized to surface particle velocity, since velocity is often considered a better measure of intensity than acceleration. Various relations between velocity and intensity have been enumerated in Neuman (Reference 17) and Medvedev (Reference 18). All possible interpretations of intensity VII, according to these published relations, were used in selecting velocity and intensity values used in the modal dynamic analysis.

Computed ground motion and intensity values are given in Table 2.4-8. The results of the modal dynamic analysis are given in Table 2.4-9. These results verify that a ground acceleration of 0.15g and a ground velocity of 9.0 in/sec are conservative for the Surry design-basis earthquake, which has intensity VII.

Comparable shear stress values for the yard area were used in the analysis of liquefaction potential, as shown in Table 2.4-10. The analysis was based on a surface acceleration of 0.15g and on piezometric data given in Section 2.4.4. The analysis further demonstrates that indicated shearing stresses used in the calculations and shown in Tables S9.12D-l and S9.12D-2 of the PSAR are conservative.

Considering the conservative nature of the calculations, such results are taken to imply that no liquefaction will occur at this site.

2.4.6 Piling

Unit loading under the turbine-generator foundation, the spent-fuel pit, the main steam shielding and safeguard area, and the refueling water storage tank are such that founding on the Pleistocene sediments would have resulted in undesirably large settlements. Accordingly, these structures are founded on piles. As an aid in selecting the pile type and appropriate loadings to be used, a series of seven piles of two different types and different lengths were driven and load-tested. A report on this test pile program is given in Reference 19. Onsite test pile data are also contained in Reference 20.

Based on the results of these tests, and considering structural arrangements and loadings, it was decided to use open-end steel pipe piles with an outside diameter of 12.75 inches by 5/16 wall thickness. Piles are driven into and derive their support from the overconsolidated Miocene clays. Tip grades for all piles are Elevation -70. To minimize disturbances of the Pleistocene clays, and to avoid lateral displacements of the soil and of structures on or buried in the soil due to driving the piles, a hole of 12-inch nominal diameter was prebored for each pile to Elevation -40.

Each pile was then cleaned out to Elevation -40 and the upper portion filled with concrete with a 28-day strength of 4000 psi.

Total lateral deflection of any given structure under dynamic loadings for clearance between structures and for design of piping, etc., is taken as the sum of shear deflections of the soil plus deflections of the piles relative to the soil. Lateral deflections of piles relative to the soil were computed using programs for lateral deflection of piles developed by Stone & Webster.

To verify these deflections, two piles driven under the spent-fuel pit were loaded laterally to shears associated with the operating-basis earthquake and the design-basis earthquake.

Test results were in excellent agreement with computed values. A report of this test is discussed in Reference 20. Stresses under vertical and lateral loadings are within normal working loads for these materials.

Allowable pile loadings for vertical loads are given in Table 2.4-11. Lateral loads are also given in Table 2.4-11. These loadings are conservative, as indicated by the results of the load tests conducted.

2.4.7 Foundation Design

A summary tabulation of the type of foundation under each of the principal plant structures is given in Table 2.4-12.

2.4.7.1 **Reactor Containment**

The reactor containment structures are founded directly on the highly preconsolidated Miocene clays, using 10-foot-thick reinforced-concrete mats. Founding grade is Elevation -41. A drainage layer consisting of 12 inches of compacted granular fill was placed directly on the clays. The six drains under the reactor containment (Section 2.4.4) connect with and drain to this drainage layer. This layer in turn connects with and is drained by a system of permanent sumps that maintain the water level in the annulus between the cofferdam and the reactor containment structure at about Elevation -33±2 feet.

To construct the containment structures, the general area was excavated from original ground surface, approximately Elevation +34, to Elevation +26.5. An area encompassing the entire power station, that is, from south of the south wall of the turbine room to about 35 feet north of the north side of the containment structures, was excavated to about Elevation +7. Local excavation was then performed as necessary to reach founding grades of the various structures. For the containment structures, this was done using two circular cofferdams consisting of steel sheet piling driven to tip grade Elevation -48. Each cofferdam is 150 feet in diameter. The sheeting was supported by reinforced-concrete ring wales. The annular space between the cofferdam and the structure is filled with porous concrete from Elevation -41 to Elevation -21.6, and above this level with carefully compacted granular fill. Both are pervious and connect with and form a portion of the drainage system around the structure. The granular fill is blanketed with 2 feet of impervious material near the top of the cofferdam to exclude water from above.

A detailed analysis of the settlement of the containment structures, including effects of heave or rebound, which is an upward movement that usually occurs in the soils under excavations as an elastic response to the removal of the weight of the soil, is presented in Reference 18. Computations of rebound for the containment structures indicated a total rebound of about 0.21 feet, of which 0.09 feet was from excavation from Elevation +26 to Elevation +7, and 0.12 feet. from excavation within the cofferdams. Four reference points for measuring heave were installed at Elevation -41 within each cofferdam before starting excavation. Observation showed good agreement between predicted and observed rebounds. Rebounds for excavation from Elevation +7 to Elevation -41 near the center of each cofferdam after completion of excavation were measured at 0.12 feet in the cofferdam for Unit 1, and 0.15 feet in the cofferdam for Unit 2. This compares with the prediction of 0.12 feet. Rebound is largely an elastic response, and is recovered quickly as load is reapplied by construction.

Deadweight load of the containment structure is approximately 7300 lb/ft^2, and is symmetrical. The actual weight of soil removed in excavating to Elevation -41 is about 8600 lb/ft^2. However, the drainage provided under these structures results in an increase in effective stresses in the underlying soil. When these factors are evaluated, a small net increase in effective stress in the soil of about 0.75 tons/ft^2 in excess of that which existed before construction is indicated, assuming the drainage to be fully effective. This is discussed in detail in Reference 21. This net added load is small compared with the overconsolidation of 4 to 5 tons/ft^2 in excess of effective stresses in these soils before start of excavation. Long-term settlements from this net loading are estimated to be less than 0.5 inch. Settlements of approximately the same magnitude are estimated for adjoining structures. Thus differential settlement between the containment structure and adjoining structures will be small.

Under the design-basis earthquake contact, the pressure under the containment is increased to 10,000 lb/ft^2. Since the founding level is 66 feet below surrounding grade, the effective stress in the soil adjoining is approximately 6950 lb/ft^2 considering drawdown of piezometric levels. Shearing strength of the Miocene clays is about 4500 lb/ft^2, and in the overlying Pleisocene clays about 1100 to 2900 lb/ft^2, 1500 lb/ft^2 being a conservative value for use as an average. The factor of safety against shear failure under the edge of the mat is in excess of 3.0, based on Terzaghi's procedure for computing bearing values for shallow foundations. This approach is conservative, since it is based on a load over the entire foundation area, whereas for the rocking mode under the design-basis earthquake the highest contact pressure occurs only under a limited portion near the edge of the foundation.

Additional settlement under these earthquake-induced loadings will be negligible, since they are well within the preconsolidation of the clay, and, further, are of such short duration that no consolidation can occur.

2.4.7.2 Spent-Fuel Building

Foundations for this structure consist of a continuous reinforced-concrete mat at Elevation 0 ft. 10 in., which is in turn supported on pipe piles into the Miocene clays with tip grades at Elevation -70. For a complete discussion of loadings on the piles, see Section 2.4.6. Sand A was excavated from beneath this structure and replaced with dense, select, granular fill. Estimated long-term settlements of this structure will be on the order of 0.5 inches.

2.4.7.3 Auxiliary Building and Control Area

These structures are founded on continuous reinforced-concrete mat foundations at Elevation -2. The mats were placed on dense, select, granular fills that replaced Sand A.

The deadload weights of these structures are less than the weight of soil removed. Soil loadings are, therefore, appreciably less than preconsolidation loadings of the Pleistocene deposits remaining. There will be small elastic settlement as loads are applied, and long-term settlements will be less than 0.5 inches. Average bearing weights are about 2.2 to 2.5 kips/ft^2. Factors of safety against edge failure exceed 3.0.

2.4.7.4 Turbine Room

The turbine generators are founded on continuous reinforced-concrete mats supported by open-ended pipe piles driven to tip grades of Elevation -70. These units average about 5000 lb/ft^2 load over the area of the mats. Estimated long-term settlements will be on the order of 0.5 inches.

The remainder of the structure is isolated from the turbine-generator foundation, and is founded on a system of continuous-strip spread footings, except for some internal columns, which are founded on spread footings. Net founding contact pressures were kept at or below 2 tons/ft^2 at Elevation +4. Where foundations were carried deeper, contact pressures were increased at the rate of 120 lb/ft^2 per foot of depth below Elevation +4.0. This recognizes the increase in bearing value allowable as footing depth below surrounding grade is increased. Bearing values are conservative, and were established considering shear strength and preconsolidation of the Pleistocene clays.

The average load of this structure is less than half the weight of soil removed. Accordingly, long-term settlements will be small.

2.4.7.5 Miscellaneous Yard Structures

The excavation for the station is backfilled to yard grade with dense, compacted granular fill. Miscellaneous small structures such as pipe enclosures, tanks, etc., are founded on or in this structural fill.

2.4.7.6 Screen Well

The river intake structure is founded on fine, clean Pleistocene sands with some interbedded clays at Elevation -27. Foundation is a reinforced-concrete mat.

The area was investigated by borings 51 through 55. These sands are quite dense, with N values in the Pleistocene formations ranging from 23 to 115. The median N value for samples from the five borings is 45 blows per foot.

Considering their density, there is no possibility of liquefaction under this structure.

The river intake structure was constructed within a steel sheet pile cofferdam, and the sheeting anchored to the structure and left in place. Tip grade of the sheeting is Elevation -51. Since the area behind the screenwell is at Elevation +11, and in front is dredged to Elevation -27, it is subject to imbalanced lateral earth loads. Its stability was analyzed and found to be satisfactory; values were as follows:

1. General slide failure through dike of intake canal:
   a. Static FS = 2.24
   b. For DBE FS = 1.53
2. Friction factors coefficient-of-sliding at foundation level (passive pressure from sheeting not considered):
   a. Static (one cell empty) 0.4
   b. DBE (operating condition) 0.4

2.4.8 Relative Earthquake Displacements

Considering the varying types of foundations used, determination of relative motion or displacements between the several structures for design of piping and rattle space was necessary.

In these analyses, displacements due to vibration and to ground movement during earthquake have been considered as follows:

1. Translation, both horizontal and vertical, and rotation of the building relative to the static position of the soil-structure interface.
2. In addition, for the auxiliary building and fuel building, lateral deflection from shear of a column of soil extending from Elevation -40 to founding grade, in accordance with the procedures outlined in a report by Dr. R. V. Whitman (Reference 22).
3. For pile-supported structures, deflection of the piles relative to the soil in which they are embedded.
4. Flexure and shear distortions of the several structures in estimating movements above the founding grades.

Vertical motions are given at the exterior of each structure. These motions include vertical translation and vertical motion of the exterior of the structure due to rocking assumed to be coincident with the vertical translation.

For the containment structure, values shown are the root mean square of the sum of the displacement for four modes of vibration, using a model with four degrees of freedom. For other structures, displacements for the fundamental periods were used, since these are relatively low, simple structures. Values of various elevations for the several structures are tabulated in Table 2.4-13.

Displacements of the piles relative to the ground were computed using a computer program developed for laterally-loaded piles and using values of the coefficient of subgrade reaction based upon physical properties of the several soil strata. Computed deflections for the 12.75-inch-diameter concrete-filled pipe piles are shown on Table 2.4-14.

To verify these displacements, a cyclic lateral load test was made on two piles located in the compacted fill area under the fuel building where Sand A was removed. These tests are discussed in Section 2.4.6. Computed and test deflections were in good agreement.

Maximum relative motions between structures were computed as the sum of the vibratory displacements of both structures at a given elevation, plus relative ground motion from Figure 2.4-21. The values so obtained are considered to be extremely conservative. They assume relative motions of the several structures to be perfectly opposed and coincident with simultaneous maximum earthquake motion displacement of appropriate direction.

To allow for these relative motions between structures, the following is provided:

1. A space of 6 inches is provided between the pile-supported fuel building and the auxiliary building, and between the fuel building and the containment structures. For other structures, the clearance is 3 inches. Intrusion of foreign material into these clearance spaces is prevented by compressible filler material.
2. Maximum relative motion between adjoining structures is included in the stress analyses of all piping that must extend from one building to another.

Adequate slack was left in electrical cables.

In addition to the movements resulting from structural vibration, there will be movements of the structures relative to each other, resulting from ground displacements from orbital earthquake motion. These have been estimated from the ground movement spectrum at periods corresponding to one-half wave length for the type of motion considered; that is, shear in the horizontal and vertical planes, and compression-rarefaction for push-pull motion, with relative motion taken as twice the spectral displacement.

Vertical motion has been assumed as two-thirds of the horizontal. These data are shown on Figure 2.4-21. This figure provides quantitative values for that portion of relative displacements between structures that is due to orbital particle motion under earthquake excitation. The relative displacement due to orbital motion is assumed to be twice the maximum single amplitude of ground displacement for a wavelength equal to twice the distance between the centroids of the structures considered. Periods are computed from these wavelengths using primary and shear wave velocities as appropriate to the orientation or relative motion and for the soil at about founding elevation. Using these periods, the amplitudes of displacement can then be computed for maximum ground acceleration and velocity.

2.4.9 Slope and Bank Stability

The site is essentially flat, except immediately at the river banks and along the north property line, where it slopes gently down to the lowlands of the game preserve. The nearest river bank is approximately 1800 feet west of the station, where the banks are about 5 feet to 25 feet high above the beach. The beach has very gentle slopes, and the river bottom offshore is nearly flat, reaching 6-foot depth about 1000 feet offshore.

The station is about 8800 feet west of the bank along the east side of the peninsula, and about 1800 feet south of the north property line. Prior to excavation, the ground surface in the station site area was generally level at about Elevation +34, except for a minor erosional channel with gentle side slopes which entered the area from the west. Adjacent to the station, the bottom of this depression was at about Elevation +24. The discharge canal follows this depression, to minimize excavation and disturbance of vegetation.

The site was excavated to a generally level grade at Elevation +26.5. Temporary excavation for the buildings and containment structures was made to about Elevation +7. After completion of construction, the area was backfilled with compacted soils to Elevation +26.5.

The discharge canal lies to the north of the station. Its centerline is approximately 380 feet from the centerline of the containment structures, and about 350 feet from the north wall of the fuel building. The cross section of the discharge canal and its relation to the station is shown in Figure 2.4-22.

The river banks and the open channel sections of the discharge canal are sufficiently distant from the station that these free-sloping surfaces will not affect the dynamic shear stresses at the station resulting from earthquake motions.

Along the river front, rather steep banks have developed because of the undercutting during heavy storm wave conditions; however, these banks are otherwise stable. Local slumping might develop under heavy earthquake conditions, but migration of such disturbance back to the station, a distance of about 1800 feet, could not occur. As indicated in Section 2.4.5, the sands underlying the site are not subject to liquefaction, and a flow slide could not develop in them.

The banks of the discharge canal at Surry have been investigated for stability. They have a factor of safety under static conditions of about 2.0.

Analyses of the stability of these banks under earthquake conditions have been made, following the basic concepts outlined by Newmark (Reference 23). In these studies, effects of increased pore pressure in the sand members under earthquake conditions have been considered.

Slide analyses have been considered for two different modes of failure: a rotational slide in a perpendicular vertical plane, where it was assumed that the lower sands had adequate friction to establish the slip plane in the medium clays at about Elevation -20 to -25; and a block slide analysis in which it was assumed that failure would develop in the lower sands because of excess pore pressures developed in these members under earthquake vibration. Tests on these sands have shown that a significant number of cycles of loading are required between the cycle when pore pressures first became equal to the overburden stresses, and the cycle when cumulative strains reach 5%.

A conservative value for the residual strength was used for the first mode of analysis by assuming zero shear strength in the sand members; that is, pore pressures in these sands were assumed to be equal to the overburden pressures along the plane of shear, although this condition holds only for a portion of the time in each pulse. N/A for these assumptions was about 1.8 for an assumed earthquake of 0.5g horizontal and 0.10g vertical acting simultaneously, indicating an adequate factor of safety and no distortion of the bank for this mode.

N/A is the ratio of acceleration applied as a static force that the bank could withstand to the maximum single-pulse ground acceleration.

For analysis of the second mode, excess pore pressures developing in about 12 cycles of loading for varying ratios of $\tau/\sigma v$ (where τ is shear stress and σv is vertical effective stress in soil mass) were determined from the results of the dynamic triaxial tests. Approximate shearing stresses and effective stresses were then evaluated at various points along the assumed plane of shear. From these data, excess pore pressures under dynamic loadings were determined. Since the excess pore pressures, as shown by the test results, ranged from a maximum to a minimum value in each cycle of loading, the mean value in each cycle was used in evaluating the excess pore pressure. These were then added to initial static-state pore pressure, assuming a 5-foot drawdown of the piezometric surface near the discharge canal to permit evaluating residual shearing strengths in the soil mass at various points under the slide block.

"N" was then determined from the ratio of the total residual shear strength to the total mass in the sliding block.

This analysis is conservative because of several factors. Excess pore pressures are zero at the start of earthquake motion, and several cycles of such motion are required, especially when the overburden effective stresses are high, before excess pore pressure becomes significant. Therefore, there could be only a few cycles of motion, rather than the 12 used where the residual shearing strength would be of the minimal values assumed. It is assumed that the excess pore pressure peaks coincide with the peak of velocity in the sliding mass. The test data from which the pore pressure was established were conservative, since initial pore pressures that may have existed at the beginning of each series of loading cycles at a given stress level were ignored in plotting the values of $\tau/\sigma v$.

N/A values on this method of analysis were in excess of 0.5 for an earthquake having a horizontal acceleration of 0.15g and vertical acceleration of 0.10g.

These studies, therefore, indicate that for the design-basis earthquake at 0.15g horizontal earthquake acceleration, there would be no significant slides or movements of the discharge canal banks.

Stability analyses made of the banks of the intake canal, based on the assumption that a combined horizontal ground motion of 0.15g and vertical ground motion of 0.10g would act simultaneously to produce maximum shearing stresses, indicated a factor of safety of 1.5 corresponding to Newmark's N/A of approximately 2.0, which indicates no displacement. Analysis was by the method of slices and assumed no loss of shear strength in sand members. If it is assumed that sand members suffered a complete loss of shear strength because of increased pore pressures under vibratory loadings, the factor of safety is reduced to 1.34. These values indicate the banks of the intake canal would be stable under earthquake conditions.

The intake canal is lined with mesh-reinforced concrete for its entire length. Since such a lining could be cracked or otherwise damaged in the event of earthquakes, an analysis was made of the rate of seepage loss. In this study, it was assumed the lining did not exist. The study was based on tests of permeability made during site investigations, described by Dames & Moore in *Revised Report - Environmental Studies, Proposed Nuclear Power Plant, Surry, Virginia,* November 17, 1967, and showed that seepage loss from the canal would be insignificant with respect to the volume of water stored. Further, the emergency service water pumps are sized with adequate margins to accommodate expected leakage from the canal. Therefore, the net loss of water from the canal, even in the event of severe damage to the lining, would be zero.

Because of the large depth and generous freeboard of the intake canal, as described in Section 10.3.4.2, settlement developing from an earthquake would not interfere with the effectiveness of the canal in providing emergency cooling.

No information was obtained after construction of the canal that would necessitate alteration of the analysis of the potential for settlement of, leakage from, or stability of the intake canal.

The estimated seepage rate from the intake canal is 40 gpm. The seepage rate can also be stated as. 00476% of the circulating water flow in the canal, with one unit operating. With two units operating, the percentage is halved. The quoted seepage rate of 40 gpm could vary by a factor of 20 or more without adversely affecting the safe-shutdown requirements for the plant. The 40 gpm represents 0.027% of the minimum capacity of one service water pump. More detailed information on the service water system is contained in Section 9.9.

2.4 REFERENCES

1. Dames & Moore, *Revised Report - Environmental Studies, Proposed Nuclear Power Plant, Surry Virginia*, November 17, 1967.
2. B. K. Meade, Report of the Subcommission on Recent Crustal Movements in North America, Paper presented at XV General Assembly of IUGG, International Association Geology, Moscow, USSR, August 2-14, 1971, NOS, NOAA, 1971.
3. G. H. Johnson, *Geology of the Yorktown, Poquoson West, and Poquosa East Quadrangles*, Report of Investigations 30, Virginia Division of Mineral Resources, 1972.
4. Surry PSAR, Supplement, pp. S9.12A-l to -8.
5. H. J. Gibbs and W. G. Holtz, *Research on Determining the Density of Sands by Spoon Penetration Testing*, Fourth International Conference on Soil Mechanics and Foundation Engineering, Vol. I, Butterworth, London, 1957.
6. Letter from C. M. Stallings, Vepco, to K. R. Goller, NRC, Subject: Differential Settlement Survey of May 1975, dated July 23, 1975, Ser. No. 541.
7. Virginia Electric and Power Company, Surry Power Station, Units 3 and 4, *Preliminary Safety Evaluation Report*, 1973.
8. Virginia Electric and Power Company, Surry Power Station, “Independent Spent Fuel Storage Installation,” *Safety Analysis Report*, October 1982.
9. Surry PSAR, Supplement, pp. S9.12C-l to -5, Table 9.12C-l, and Figure S9.12C-1.
10. Surry PSAR, Supplement, pp. S9.12D-l to -6 and Figures S9.12D-1, -2, and -3.
11. Surry PSAR, Supplement, pp. S9.12C-l to -5, and Figure S9.12C-1.
12. Surry PSAR, Supplement, Section S9.12A.
13. Surry PSAR, Supplement, Section S9.12D.
14. Surry PSAR, Supplement, p. S9.12D-4, Table S9.12D-l.
15. Surry PSAR, Supplement, Section S9.12D.
16. R. V. Whitman and J. M. Roesset, *Theoretical Background for Amplification Studies*, MIT Research Report, R69-15, March 1969.
17. F. Neuman, *Earthquake Intensity and Related Ground Motion*, University of Washington Press, Seattle, 1954.
18. S. V. Medvedev, “Deformation and Strain in Foundations of Structures from Strong Earthquakes,” in *Problems in Engineering Seismology*, No. 8, Akad. Nauk SSSR Inst. Fiziki Zemli Trudy, Vol. 28, Table 5.
19. Stone & Webster Corporation, *Test Pile Program, Surry Power Station*, July 1968.

20. Stone & Webster Corporation, *Lateral Load Pile Test, Surry Power Station*, July 1968.

21. Stone & Webster Corporation, *Rebound and Settlement Analysis, Surry Power Station*.

22. R. V. Whitman, *Report upon Foundation Dynamics for the Proposed Nuclear Power Plant at Surry, Virginia*, Massachusetts Institute of Technology, Cambridge, Mass., July 1967.

23. N. M. Newmark, “Effects of Earthquake on Dams and Embankments,” *Geotechnique*, Vol. XV, No. 2, June 1965.

Table 2.4-1
OROGENIC MOVEMENTS IN THE CENTRAL APPALACHIAN REGION

Orogenic Episode and Approximate Time Interval	Known Area of Influence	Maximum Manifestation
APPALACHIAN MOVEMENTS		
Palisadian		
Late Triassic (Carnian-Norian) 190 to 200 million years	Belt along central axis of already completed mountain chain	Fault troughs, broad warping, basaltic lava, dike swarms
Allegheny		
Pennsylvania and/or Permian (Westphalian and later) 230 to 260 million years	West side of central and southern Appalachians, south-east side of northern Appalachians; perhaps also in Carolinian Piedmont	Strong folding, also middle-grade metamorphism and granite intrusion at least in southern New England
Acadian		
Devonian, mainly Middle but Episodic into Mississippian (Emsian-Givetian 360 to 400 million years)	Whole of northern Appalachians, except along northwest edge; as far southwest as Pennsylvania	Medium-to high-grade metamorphism, granite intrusion
Taconic		
Middle (and late) Ordovician (Caradocian, locally probably older) 450 to 500 million years	General on northwest side of northern Appalachians, local elsewhere; an early phase in Carolinas and Virginia, perhaps general in Piedmont province	Strong angular unconformity, gravity slides, at least low-grade metamorphism, granodmafic intrusion
Avalonian		
Latest Precambrian 580 to 600 million years	Southeastern Newfoundland, Cape Breton Island, southern New Brunswick; probably also central and southern Appalachians	Probably some deformation uplift of sources of coarse arkosic debris, gravity slides
GREENVILLE (PRE-APPALACHIAN) MOVEMENTS		
Late Precambrian 800 to 1100 million years	Eastern North America, including western part of Appalachian region	High-grade metamorphism, granitic and other intrusion

Table 2.4-2

DENSITY DATA FOR SAND MEMBERS, FROM ONSITE TESTS IN COFFERDAM

Sample No.	Percent Passing No. 200	Field Density	Minimum Density, lb/ft	Modified Proctor, F&R	Percent Compaction of Modified Proctor	Maximum Density, lb/ft, Dry Vibratory Compaction		Relative Density	
						A	B	Vibration,%	Ramming,%
Sand A (Upper Sand)									
S1-1	12.3	107.6	NA	108.1	99.5	-	-	-	-
S1-2	10.2	102.9	85.6	108.1	95.2	108.0	-	81	81
S2-1	6.0	101.3	75.9	101.7	99.6	104.0	102.0	92	98
S2-2	12.3	97.3	74.2	107.4	90.6	96.5	94.4	100	76
S2-3	16.8	94.3	66.6	105.3	89.6	92.5	102.1	85	80
S2-4	13.3	96.8	68.5	105.3	91.9	93.6	96.0	100	84
S2-5	22.1	105.2	68.8	113.1	93.0	96.0	96.5	100	89
S2-6	4.5	89.7	74.7	100.5	89.3	99.0	97.8	68	65
Sand B (Lower Sand)									
S1-3	12.3	94.2	NA	106.9	88.1				
S1-4	28.3	105.1	NA	108.9	96.5				
S1-5	36.9	110.5	NA	118.8	93.0				
S1-6		100.7		124.9					
S1-7		103.7		-					

Table 2.4-2 (CONTINUED)

DENSITY DATA FOR SAND MEMBERS, FROM ONSITE TESTS IN COFFERDAM

Sample No.	Percent Passing No. 200	Field Density	Minimum Density, lb/ft	Modified Proctor, F&R	Percent Compaction of Modified Proctor	Maximum Density, lb/ft, Dry Vibratory Compaction		Relative Density	
						A	B	Vibration,%	Ramming,%
Sand B (Lower Sand) (continued)									
S1-8		108.1		117.9					
S1-9		101.9		-					

From Undisturbed Samples from Borings by Dames & Moore

Boring	Elevation	Percent Passing No. 200	Field Density	Laboratory Date		Relative Density,%
				Min	Max	
Upper Sand A						
46	+1.0	26	103.3	76.8	103.6	98
	-4.0		93.0	81.0	99.3	70
49	+2	27	95.0	81.5	103.0	68
	-0.5		90.8	79.5	97.6	67
Lower Sand B						
46	-30	14	98.3	78.5	101.9	92
	-32	6	97.0	75.3	98.5	95

Table 2.4-2 (CONTINUED)
DENSITY DATA FOR SAND MEMBERS, FROM ONSITE TESTS IN COFFERDAM

Sample No.	Percent Passing No. 200	Field Density	Minimum Density, lb/ft	Modified Proctor, F&R	Percent Compaction of Modified Proctor	Maximum Density, lb/ft, Dry Vibratory Compaction		Relative Density	
						A	B	Vibration,%	Ramming,%

Notes: Minimum Density - Minimum of three trials, tests give excellent reproducibility - ASTM-D20-49-64T.

Vibratory compaction A - Placed oven dry in six layers under surcharge of 1 psi - tapped firmly for 3 minutes after each layer was placed.

B - Same as above except sample saturated with excess water on surface.

Where relative density is computed using vibratory test data, the higher of the two test values was used.

For samples marked “NA” under Minimum Density, there was significant dry strength, making the test procedure not applicable.

Table 2.4-3
GRAIN SIZE ANALYSIS, SAND B, COFFERDAM NO. 1

Percent of Material Passing

Sieve Size	Elevation -26.6	-27.6	-28.6	-29.6	-30.6	-31.6	-32.1	-32.6	-33.6	-34.6	-35.6	-36.6
1									100	100		
3/4									97.	88.4		
1/2									85.2	65.8		
3/8							100		78.9	54.7		
No. 4		100		100	100		97.1		61.9	41.4	100	
No. 10	100	99.9	100	93.9	99.4		95.7	100	55.0	31.7	99.6	
No. 20	99.9	99.8	99.9	93.5	99.3	100	95.3	99.8	42.8	28.4	99.4	100
No. 40	99.2	99.6	99.8	93.1	99.0	99.8	94.1	99.5	27.3	20.6	98.7	99.9
No. 60	98.1	95.5	98.1	89.4	91.4	96.2	89.7	96.2	17.8	13.5	97.8	99.8
No. 140	57.9	26.5	41.0	35.1	15.8	30.0	23.2	43.7	3.5	2.0	58.8	73.6
No. 200	41.2	16.6	28.4	24.2	8.4	16.7	13.9	28.6	2.3	1.4	45.6	52.4

Note: All samples washed through No. 200 mesh screen.

Table 2.4-4
PENETRATION RESISTANCE FROM BORINGS, SAND A (UPPER SAND)

Boring No.	Blow Count, N	Adjusted Blow Count, N'	Type Sampler	Elevation, ft	Overburden Effective Stress, psf
Group 1 Borings (made from Elevation +26 or higher)					
B-8A	25	25	SS	-4.2	3210
B-8A	24	24	D&M	-9.2	3498
B-9	12	15	D&M	-5.0	4160
B-9	53	66	D&M	-10.0	4450
B-11	19	24	D&M	-3.0	3090
B-11	45	56	D&M	-7.5	3350
B-12A	28	28	SS	-6.7	3415
B-12A	24	24	SS	-13.2	3790
B-13A	65	65	SS	-8.2	3440
B-13A	26	26	SS	-12.7	3700
B-14A	18	18	SS	-12.78	3636
B-14A	26	26	SS	-18.78	3980
B-15	48	60	D&M	-5.0	3010
B-16	57	71	D&M	-11.1	4490
B-17	25	31	D&M	+4.0	3680
B-17	38	48	D&M	0.0	3920
B-17	49	61	D&M	-5.8	4250
B-18	41	51	D&M	-8.8	4030
B-18	36	45	D&M	-13.0	4270
B-18	24	30	SS	-18.5	4590
B-19A	24	24	SS	-3.7	3035
B-19A	14	14	SS	-8.7	3350
B-19A	13	13	SS	-13.2	3610
B-19A	14	14	SS	-18.2	3890
B-19A	15	15	SS	-23.2	4190

Table 2.4-4 (CONTINUED)
PENETRATION RESISTANCE FROM BORINGS, SAND A (UPPER SAND)

Boring No.	Blow Count, N	Adjusted Blow Count, N'	Type Sampler	Elevation, ft	Overburden Effective Stress, psf
Group 1 Borings (made from Elevation +26 or higher)					
B-19A	20	20	SS	-28.2	4473
B-19A	20	20	D&M	-31.6	4670
B-22	24	30	D&M	+0.5	3980
B-22	28	35	D&M	-4.5	4270
B-23A	29	29	SS	+5.0	600
B-23A	11	11	SS	0.0	775
B-24	18	22	D&M	-9.0	4570
B-25	50	62	D&M	0.0	3990
B-26	37	46	D&M	-4.0	4220
B-26	70	87	D&M	-6.3	4350
B-45A	11	14	D&M	-3.0	850
B-45A	11	14	D&M	-6.3	1040
B-45A	9	11	D&M	-9.0	1200
B-45A	10	12	D&M	-11.3	1330
B-47	15	19	D&M	-4.3	900
B-48	21	21	SS	-1.5	680
B-48	15	19	D&M	-4.5	850
B-49A	24	30	D&M	+4.0	430
B-49A	28	35	D&M	+1.2	590
B-49A	33	41	D&M	0.0	660
B-49A	41	51	D&M	-2.8	830
B-50A	7	9	D&M	-1.0	610
B-50A	41	51	D&M	-4.1	790
B-50B	8	8	SS	-0.1	584
B-50B	11	11	SS	-5.1	874
B-20A	17	17	SS	+2.1	540

Table 2.4-4 (CONTINUED)
PENETRATION RESISTANCE FROM BORINGS, SAND A (UPPER SAND)

Boring No.	Blow Count, N	Adjusted Blow Count, N'	Type Sampler	Elevation, ft	Overburden Effective Stress, psf
Group 1 Borings (made from Elevation +26 or higher)					
B-20A	15	15	SS	-2.4	800

Notes: D&M - 2.5-inch i.d. sampler driven using 300-lb weight falling 18 inches.

SS - standard penetration test, 1-3/8-inch-i.d. sampler driven by 140-lb weight falling 30 inches.

Plotting of data from samples taken alternatively with both samplers indicates that soil requiring 10 blows per foot. for standard penetration test would require eight blows per foot with the D&M sampler. N' values have been adjusted by this ratio for samples taken with D&M sampler.

Boring designated by suffix A or 8A were made 3 feet south or 3 feet north of original boring. Where supplementary boring has been made, original boring has been omitted.

Table 2.4-5
PENETRATION RESISTANCE FROM BORINGS, SAND B (LOWER SAND)

Boring No.	Blow Count, N	Adjusted Blow Count, N'	Type Sampler	Elevation, ft	Overburden Effective Stress, psf
Group 1 Borings					
B-8A	18	18	SS	-22.2	4248
B-8A	10	10	SS	-27.2	4535
B-8A	18	18	SS	-32.2	4825
B-9	25	31	D&M	-15.0	4740
B-9	23	29	D&M	-17.0	4850
B-11	13	16	D&M	-27.0	4490
B-12A	12	12	SS	-16.7	3990
B-12A	10	10	SS	-22.7	4335
B-12A	10	10	SS	-26.7	4567
B-12A	11	11	SS	-31.7	4800
B-13A	58	58	SS	-18.7	4045
B-13A	18	18	SS	-23.7	4333
B-13A	22	22	SS	-28.7	4622
B-13A	28	28	SS	-33.7	4910
B-14	10	12	D&M	-15.8	4760
B-14A	18	18	SS	-12.8	3635
B-14A	26	26	SS	-17.8	3922
B-14A	30	30	SS	-22.8	4210
B-14A	25	25	SS	-27.8	4500
B-15	17	21	D&M	-24.8	4150
B-15	20	25	D&M	-29.5	4430
B-16	12	15	D&M	-29.7	5570
B-17	20	25	D&M	-35.0	5950
B-18	17	21	D&M	-20.5	4710
B-18	15	19	D&M	-23.0	4850

Table 2.4-5 (CONTINUED)
PENETRATION RESISTANCE FROM BORINGS, SAND B (LOWER SAND)

Boring No.	Blow Count, N	Adjusted Blow Count, N'	Type Sampler	Elevation, ft	Overburden Effective Stress, psf
Group 1 Borings (continued)					
B-18	13	16	D&M	-28.5	5170
B-18	17	21	D&M	-32.5	5400
B-19A	15	15	SS	-24.2	4242
B-19A	20	20	SS	-29.2	4530
B-19A	19	19	SS	-34.2	4818
B-23A	14	14	SS	-29.0	2683
B-23A	68	68	SS	-33.0	2971
B-24	18	22	D&M	-23.6	5420
B-24	17	21	D&M	-28.5	5700
B-25	62	77	D&M	-4.5	4250
Group 2 Borings					
B-20A	11	11	SS	-24.9	2099
B-20A	20	20	SS	-29.9	2387
B-20A	20	20	SS	-34.9	2675
B-45	9	9	SS	-29.3	2380
B-45	19	24	D&M	-32.8	2580
B-47	19	19	SS	-25.0	2100
B-47	16	20	D&M	-28.0	2280
B-47	27	27	SS	-31.2	2460
B-47	16	20	D&M	-34.0	2620
B-48	27	34	D&M	-39.3	2870
B-50	14	14	SS	-21.2	1790
B-50A	8	8	SS	-21.1	2036
B-50A	13	13	SS	-26.6	2352
B-50A	23	23	SS	-31.6	2640

Table 2.4-5 (CONTINUED)
PENETRATION RESISTANCE FROM BORINGS, SAND B (LOWER SAND)

Boring No.	Blow Count, N	Adjusted Blow Count, N'	Type Sampler	Elevation, ft	Overburden Effective Stress, psf
Group 2 Borings (continued)					
B-50A	35	35	SS	-35.6	2928

Notes: D&M - 2.5-inch i.d. sampler driven using 300-lb weight falling 18 inches.

SS - standard penetration test, 1-3/8 inch-i.d. sampler driven by 140-lb weight falling 30 inch.

Plotting of data from samples taken alternatively with both samplers indicates that soil requiring 10 blows per foot for standard penetration test would require eight blows per foot with the D&M sampler. N' values have been adjusted by this ratio for samples taken with D&M sampler.

Boring designated by suffix A or 8A were made 3 feet south or 3 feet north of original boring. Where supplementary boring has been made, original boring has been omitted.

Table 2.4-6
DIFFERENTIAL MOVEMENT (FT)

Interface[a]	Survey 1 11-10-75	Survey 2 5-20-76	Survey 3 1-10-77	Survey 4 5-26-77
1	.005	.004	.005	.001
2	.006	.001	.004	.003
3	.004	.003	.002	.001
4	.003	.001	.006	.001
5	.005	.002	.010	.001
6	.008	.005	.006	.004
7	.002	.003	.001	.001
8	.002	.009	.013	.005
9	.009	.012	.016	.012
10	.001	.004	.004	.006
11	.001	.001	.001	.001

a. Interface Designations (see Figure 2.4-10)

1. Northwest corner, auxiliary building/southeast side, Unit 1 cable vault.
2. South side, Unit 1 containment/southwest corner, Unit 1 auxiliary feed pump room.
3. Northwest side, Unit 1 containment spray pump room/southwest side, Unit 1 safeguards valve pit.
4. Northeast corner, Unit 1 safeguards valve pit/west side, Unit 1 containment.
5. Northeast side, Unit 1 containment/northwest corner, fuel building.
6. Northeast corner, fuel building/northwest side, Unit 2 containment.
7. Southeast corner, Unit 2 containment/northeast corner, Unit 2 containment spray pump room.
8. Southeast corner, Unit 2 auxiliary feed pump room/southside, Unit 2 containment.
9. North side, service building/south side, Unit 2 containment.
10. Southwest corner, Unit 2 cable vault/northeast corner, auxiliary building.
11. North side, service building/southeast corner, auxiliary building.

Table 2.4-7
PIEZOMETER COMPARISON DATA

		Piezometric Level	
Piezometer	Tip in Sand	11-2-67	1-26-71
P1A	A	+1.1	+1.0
P1B	A	+1.3	+0.7
P1C	B	+1.9	+1.3
P2A	A	+3.7	+2.8
P2B	B	+3.5	+2.3

Table 2.4-8
COMPUTED GROUND MOTION AND INTENSITY, LIQUEFACTION ANALYSIS

Ground Motion			
		Intensity, MM	
Velocity, in./sec	Acceleration, g	After Neuman	Medvedev
6.3	0.07	7.7	8.6
8.3	0.10	8.2	8.9

Table 2.4-9
MODAL DYNAMIC ANALYSIS

	Shear Stress, lb/ft^2			
	At Elevation -5		At Elevation -30	
	5 largest peaks		5 largest peaks	
Velocity at surface, in./sec	Max	Avg	Max	Avg
6.1	250	180	380	280
8.3	350	250	540	390

Table 2.4-10
SHEAR STRESS VALUE FOR YARD AREA,
LIQUEFACTION ANALYSIS

	Shear Stress, lb/ft^2 (average of 8 largest peaks)	
Ground Acceleration	At Elevation -5	At Elevation -30
0.15g (DBE)	390	620
0.25g (hypothetical)	640	1025

Table 2.4-11
ALLOWABLE PILE HOLDINGS

I. Vertical Loads	Allowable Pile Loading
Static load (dead load and fluid and equipment and design live load on floors)	60 tons each
Static and earthquake load	60 tons each, plus 1/3 increase for OBE, or 60 tons each, plus 1/2 increase for DBE
II. Lateral Loads	
OBE	12 kips each
DBE	22 kips each

Table 2.4-12
FOUNDATION TYPES

Structure	Type of Foundation
Reactor containment	10-ft reinforced-concrete mat on Miocene clay
Fuel building	6-ft reinforced-concrete mat into preconsolidated Miocene clays, pile load 60 tons each
Auxiliary building	4-ft reinforced-concrete mat on compacted granular fill, replacing Sand A
Control house	Reinforced-concrete mat on compacted granular fill, replacing Sand A
Intake structure	3-ft reinforced-concrete mat on Pleistocene clays

Table 2.4-13
DISPLACEMENTS UNDER EARTHQUAKE[a]

	Displacement, in.±					
	0.07g Acceleration			0.15g Acceleration		
Structure[b]	E-W	N-S	Vertical at External Wall	E-W	N-S	Vertical at External Wall
Containment structure						
At mat (Elevation -40)	0.15	0.15		0.25	0.25	
At Elevation +70	0.5	0.5	0.25	0.8	0.8	0.5
At top of dome	0.75	0.75		1.25	1.25	
Fuel building						
Pile movement only	0.12	0.12		0.25	0.25	
At foundation mat	0.25	0.35		0.5	0.65	
At roof (Elevation +72)	0.4	0.6	0.2	0.7	1.1	0.4
Auxiliary building						
At foundation mat	0.2	0.2		0.4	0.4	
At roof (Elevation +66)	0.5	0.5	0.25	0.9	0.9	0.5

a. Basic procedures used to compute values shown in this table, values that essentially represent motions of structures relative to the static position of ground, are given in Section 2.4.8. Soil values and computational procedures used in making these computations are given in Reference 16. The fuel building is supported on fixed end piles, and pile deflections, as indicated, are added to computed soil deflections for this structure in arriving at values shown in this table.

b. Clearance between structures: Fuel building to vapor containment and auxiliary building - 6-in. minimum at all levels.
Auxiliary building to vapor containment - 3-in. minimum at all levels.
Auxiliary building to control room and battery area - 3-in. minimum at all levels.

Table 2.4-13 (CONTINUED)
DISPLACEMENTS UNDER EARTHQUAKE[a]

	Displacement, in.±					
	0.07g Acceleration			0.15g Acceleration		
Structure[b]	E-W	N-S	Vertical at External Wall	E-W	N-S	Vertical at External Wall
Control room and battery area						
At foundation mat	-	0.1		0.1	0.15	
At Elevation +10	-	0.1	0.3	0.1	0.15	0.6
At Elevation +113 (roof trusses of turbine building)	0.2	0.5		0.4	1.2	
Turbine pedestal						
At mat	0.2	0.25	0.1	0.3	0.4	0.2
At Elevation 58.5	0.3	0.5		0.5	0.8	

a. Basic procedures used to compute values shown in this table, values that essentially represent motions of structures relative to the static position of ground, are given in Section 2.4.8. Soil values and computational procedures used in making these computations are given in Reference 16. The fuel building is supported on fixed end piles, and pile deflections, as indicated, are added to computed soil deflections for this structure in arriving at values shown in this table.

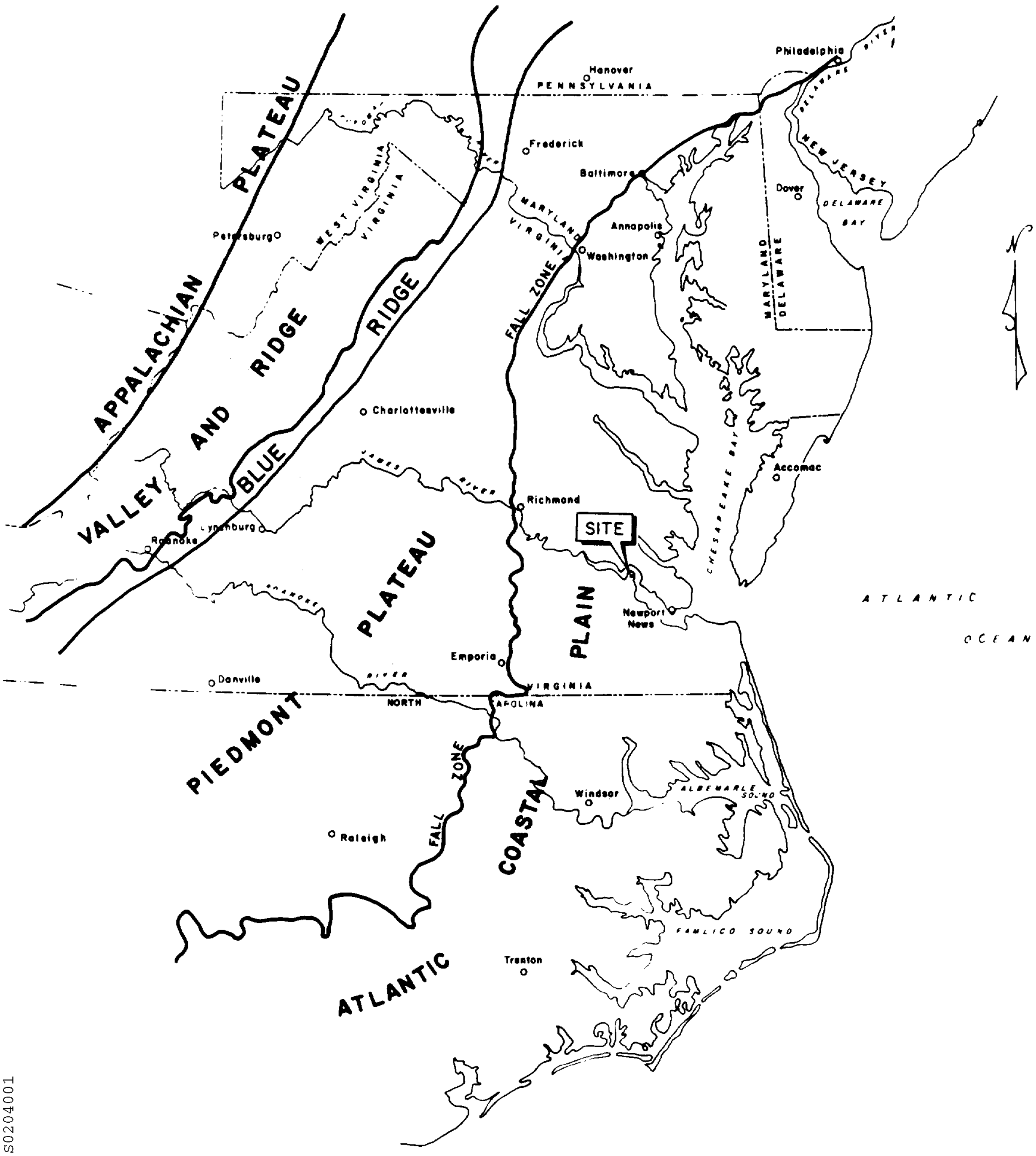
b. Clearance between structures: Fuel building to vapor containment and auxiliary building - 6-in. minimum at all levels.
Auxiliary building to vapor containment - 3-in. minimum at all levels.
Auxiliary building to control room and battery area - 3-in. minimum at all levels.

Table 2.4-14
COMPUTED DEFLECTIONS FOR CONCRETE-FILLED PIPE PILINGS

Shear Load at Top, kips	Deflection, Free-End Pile, in.	Deflection, Fixed-End Pile, in.
12	0.34	0.12
22	0.6	0.23

Note: The two shear loadings quoted correspond to the shear per pile at 0.07g operating-basis earthquake and 0.15g design-basis earthquake ground accelerations, and 0.05 and 0.10 damping, respectively.

Figure 2.4-1
REGIONAL PHYSIOGRAPHY



S0204001

Figure 2.4-2
REGIONAL GEOLOGY

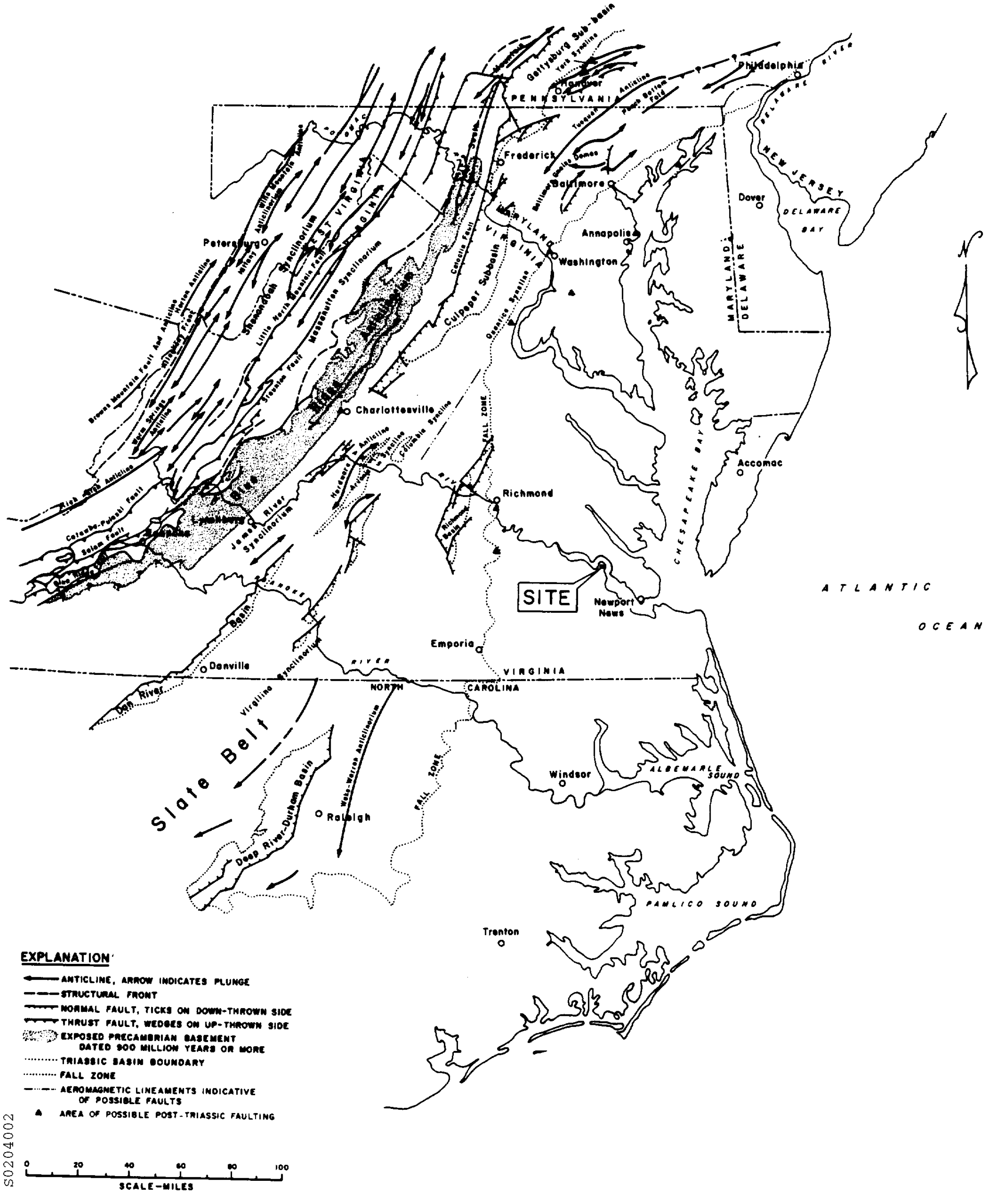
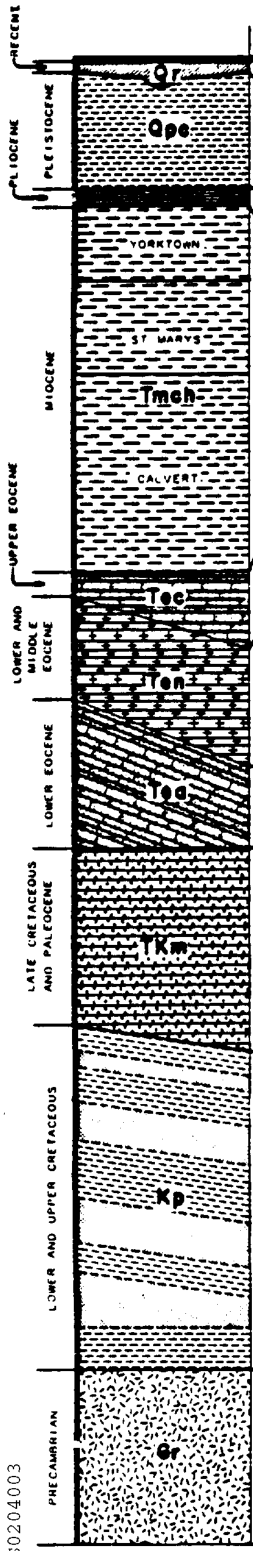
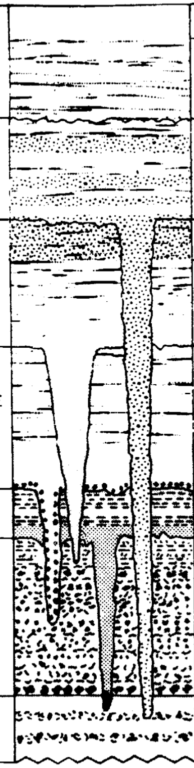


Figure 2.4-3
COLUMNAR GEOLOGIC SECTION



GEOLOGIC AGE AND DESCRIPTION	ORIGIN	DISTRIBUTION	WATER-BEARING PROPERTIES
Recent alluvium, beach and organic sediments such as found on Hog Island Waterfowl Refuge.	Deposited by ocean currents.	Thick deposits present only at Hampton	May yield a little water to shallow wells.
Pleistocene Columbia group. Consists of clays and sands that make up the surficial terraces. Marly strata are present in easternmost terraces only.	The higher westerly terraces are of continental origin, but the lower easterly terraces are of marine origin.	Exposed at the surface throughout the area.	Excellent water-bearing formation for domestic and small industrial supplies.
Bacon's Castle formation and Sedley formation of Pliocene age.	Sediments of Bacon's Castle formation are of fluvial origin. Sedley formation is of marine origin.		
The Chesapeake group of Miocene age consists of shell marl, dark-blue or gray clay, and subordinate sandy strata. The Yorktown formation is sandy and very fossiliferous. The St. Marys formation consists of tough blue or gray clays. The Calvert formation is diatomaceous and sandy but is less fossiliferous than the Yorktown formation.	Deposited in marine waters but may have extended inland some distance west of the present Fall Line.	Exposed in stream beds except at Hampton and lower Warwick, where it is concealed by younger sediments. The Yorktown and St. Marys formations crop out throughout the central and western area and the Calvert formation crops out along the Fall Line.	Yorktown formation yields small quantities of hard water to wells. St. Marys formation is not water-bearing. Calvert formation yields small to moderate supplies of water in many places. At Yorktown and in the lower peninsula area the water may be somewhat brackish.
Upper Eocene Chickahominy formation. Consists of gray marl beds containing glauconite and pyrite. Highly foraminiferal.	Deposited in marine waters.	Known from well cuttings at Yorktown, Camp Peary, Jamestown, Fort Eustis, Newport News, and Fort Monroe. Thins to a vanishing point before approaching the Fall Line.	Not a water-bearing formation at Yorktown. Some thin water-bearing sand beds in central part of the peninsula are probably Chickahominy formation.
Lower and Middle Eocene Nanjemoy formation. Consists of gray marl glauconite and quartz sand, and thin limestone beds.	Deposited in marine waters.	Typical exposure from the Fall Line to Williamsburg, but may be thinner or absent east of Williamsburg. Lower Eocene part of the formation thins to a vanishing point about 20 miles east of the Fall Line. Middle Eocene part may be quite thin in vicinity of Newport News.	Yields ample water for domestic supplies along the lower Chickahominy River and at the head of the York River. Water for industrial use is pumped at West Point.
Lower Eocene Aquia formation. Consists of glauconitic marl and basal quartz sand beds. Maximum thickness about 125 feet.	Deposited in marine waters.	Occurs along the Fall Line. Formation is exposed at the surface near Richmond. No unconformity with underlying Mattaponi formation.	Basal sands yield moderate supplies of water to wells in Hanover, Henrico, and western King William Counties.
Late Cretaceous and Paleocene Mattaponi formation. Consists of mottled clay, glauconitic sand and marl, and thick basal quartz sand.	Deposited in estuaries and bays.	Occurs at depth in central and eastern parts of the Coastal Plain as far west as the Fall Line.	A prolific water-bearing formation tapped by many domestic and a few industrial wells, notable at West Point and Newport News. The formation constitutes a vast reserve of fresh water in the central Coastal Plain. East of Williamsburg, the formation yields brackish water.
Potomac group of lower and Upper Cretaceous sands and clay beds.	Deltaic sediments deposited in fresh to slightly brackish waters.	The formation crops out in the vicinity of Richmond but lies beyond the reach of most wells a short distance east of the Fall Line (See plate 1).	The formation yields water to a few wells near the Fall Line but elsewhere it is not yet reached by wells.
Pre-Cambrian metamorphosed igneous and sedimentary rock. Granite.	Igneous intrusive rocks.	Crops out along the Fall Line except where Triassic units are present. Underlies entire Coastal Plain.	Yields small to moderate supplies of water to wells along or near the Fall Line.

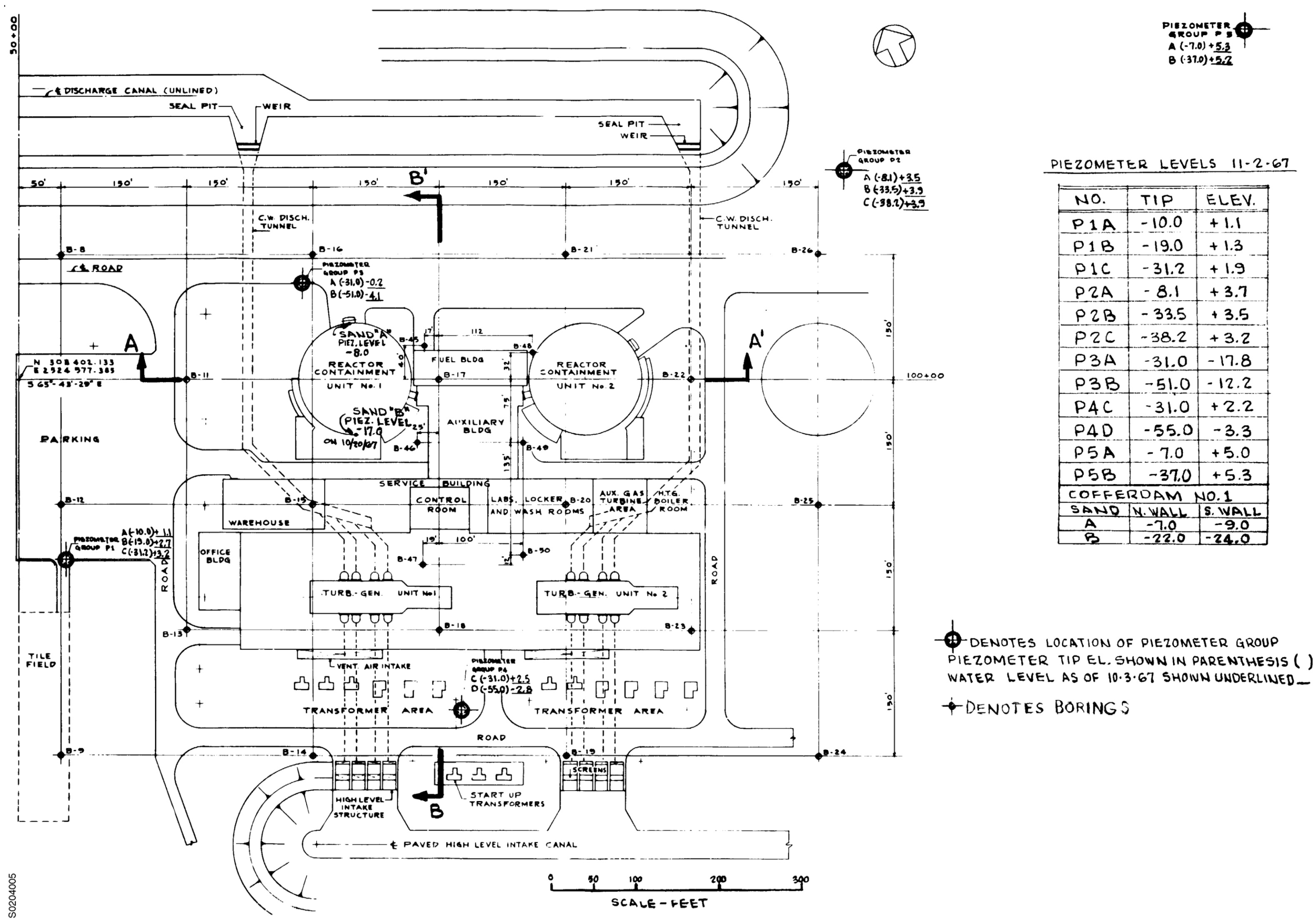
Figure 2.4-4
SITE STRATIGRAPHIC COLUMN OF QUATERNARY AND UPPER MIOCENE FORMATIONS



		DESCRIPTION	ORIGIN	DISTRIBUTION	WATER BEARING PROPERTIES	THICKNESS
HOLOCENE	ALLUVIUM	CHIEFLY ORGANIC SILTS AND CLAYS OF SWAMPS AND MARSHES, SOME CHANNEL AND BEACH SANDS	FLUVIAL AND TIDAL-MARSH	ALONG STREAM VALLEYS, TIDAL MARSHES AND CHANNELS, AND BEACH SANDS.	MAY YIELD A LITTLE WATER TO SHALLOW WELLS.	0-50 FT.
PLEISTOCENE	NORFOLK FORMATION	INTERBEDDED SANDS, CLAYS, AND ORGANIC SILTS, AND SANDY GRAVEL	FLUVIAL ESTUARINE	EXPOSED AT THE SURFACE THROUGHOUT THE SITE VICINITY	EXCELLENT WATER-BEARING FORMATION FOR DOMESTIC AND SMALL INDUSTRIAL SUPPLIES	70-80 FT.
PLEISTOCENE	WINDSOR FORMATION	UPPER MEMBER-POORLY SORTED MIXTURE OF SAND, SILT AND CLAY	LITTORAL	NOT FOUND AT THE SITE		0
		LOWER MEMBER-INTERTONGUED SANDS AND CLAYS. LOWER PART CHIEFLY CROSS-BEDDED SAND, UPPER PART CHIEFLY CLAY	FLUVIAL ESTUARINE			
PLIOCENE &/OR PLEISTOCENE	BACONS CASTLE FORMATION	INTERTONGUED SANDS AND CLAYS PROMINENT RED COLORATION LOWER PART CHIEFLY CROSS-BEDDED SANDS, UPPER PART CHIEFLY CLAY, GRAVEL AT BASE	FLUVIAL	NOT FOUND AT THE SITE		0
PLIOCENE &/OR PLEISTOCENE	SEDLEY FORMATION	BROWN SANDS AND CLAYS	ESTUARINE	NOT FOUND AT THE SITE		0
MIOCENE	YORKTOWN FORMATION	UNIT-4 GRAY CLAY WITH INTERCALATED 1" BEDS OF SHELL DEBRIS UNIT-3 HIGHLY FOSSILIFEROUS BEDS UNIT-2 HIGHLY FOSSILIFEROUS BEDS CONTAINING CHAMA CONGREGATA UNIT-1 SANDY FOSSILIFEROUS BEDS PECTEN CLINTONIUS BASAL 6"-8"	MARINE	CROPS OUT WEST OF THE SITE AREA AND FOUND IN BORINGS AT THE SITE AT EL. -40±	YIELDS SMALL QUANTITIES OF HARD WATER TO WELLS. WATER MAY BE BRACKISH	130± FT. ESTIMATED FROM DEEP WELLS IN THE AREA
MIOCENE	ST. MARYS FORMATION	INTERBEDDED SANDS AND HIGH FOSSILIFEROUS SANDS CONTAINING ISOGNOMON MAXILLATA	MARINE	CROPS OUT WEST OF THE SITE AREA FOUND IN DEEP WELLS IN THE VICINITY OF THE SITE.	THIS FORMATION IS NOT WATER BEARING	40± FT. ESTIMATED FROM DEEP WELLS IN THE AREA

S0204004

Figure 2.4-5
PLAN LOCATION OF BORINGS AND PIEZOMETERS



PIEZOMETER LEVELS 11-2-67

NO.	TIP	ELEV.
P1A	-10.0	+ 1.1
P1B	-19.0	+ 1.3
P1C	-31.2	+ 1.9
P2A	- 8.1	+ 3.7
P2B	- 33.5	+ 3.5
P2C	-38.2	+ 3.2
P3A	-31.0	- 17.8
P3B	-51.0	- 12.2
P4C	-31.0	+ 2.2
P4D	-55.0	- 3.3
P5A	- 7.0	+ 5.0
P5B	-37.0	+ 5.3
COFFERDAM NO. 1		
SAND	N. WALL	S. WALL
A	-7.0	-9.0
B	-22.0	-24.0

DENOTES LOCATION OF PIEZOMETER GROUP
PIEZOMETER TIP EL. SHOWN IN PARENTHESIS ( )
WATER LEVEL AS OF 10-3-67 SHOWN UNDERLINED

DENOTES BORINGS

Figure 2.4-6
SUBSURFACE PROFILES—SHEET 1

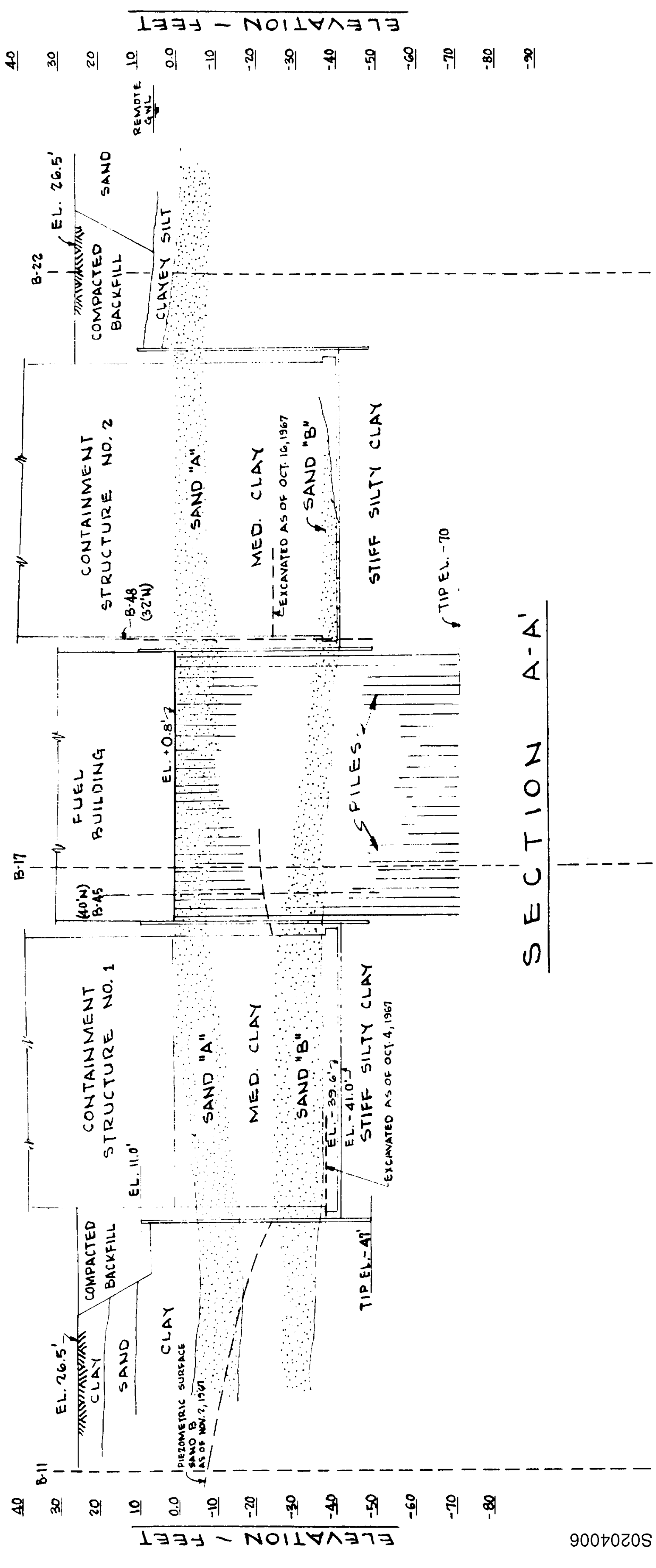


Figure 2.4-7
SUBSURFACE PROFILES—SHEET 2

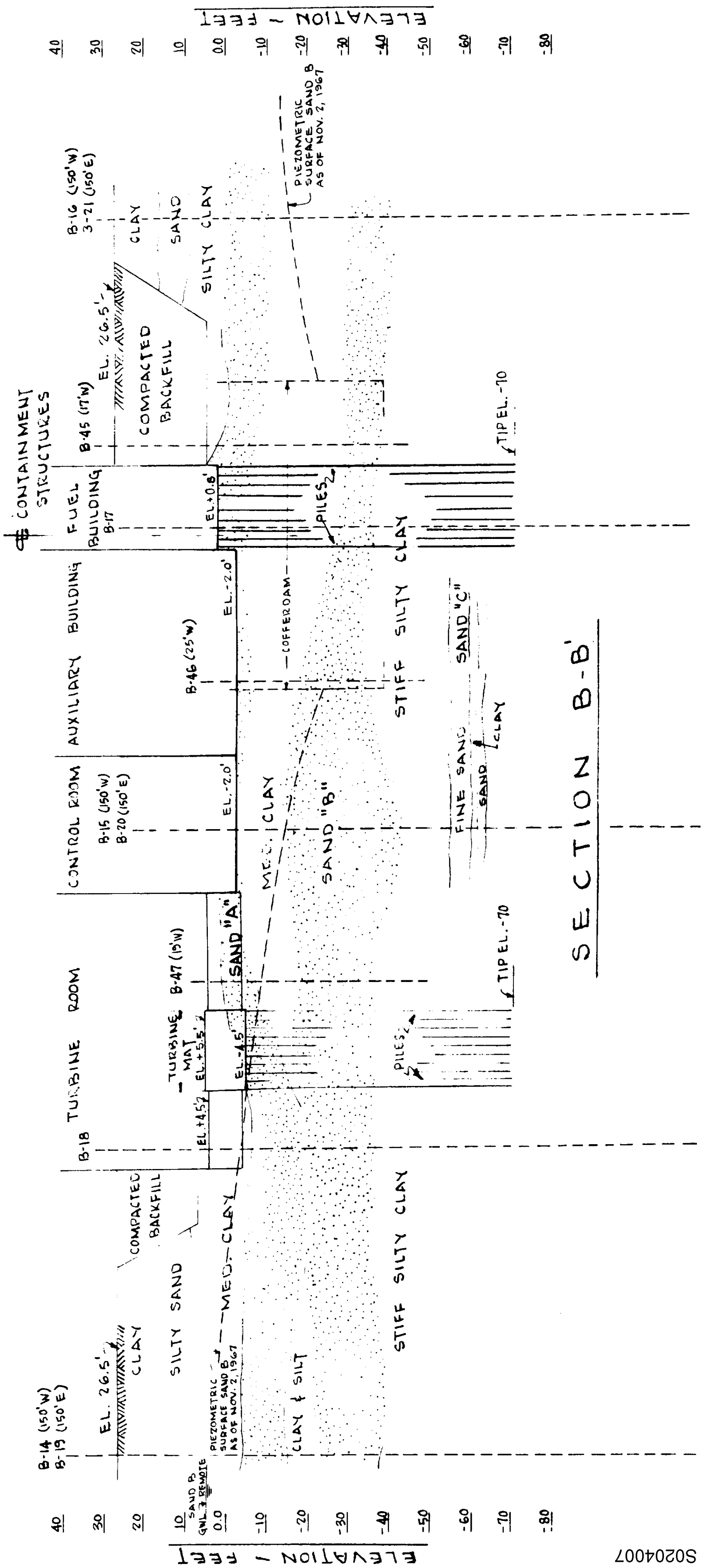
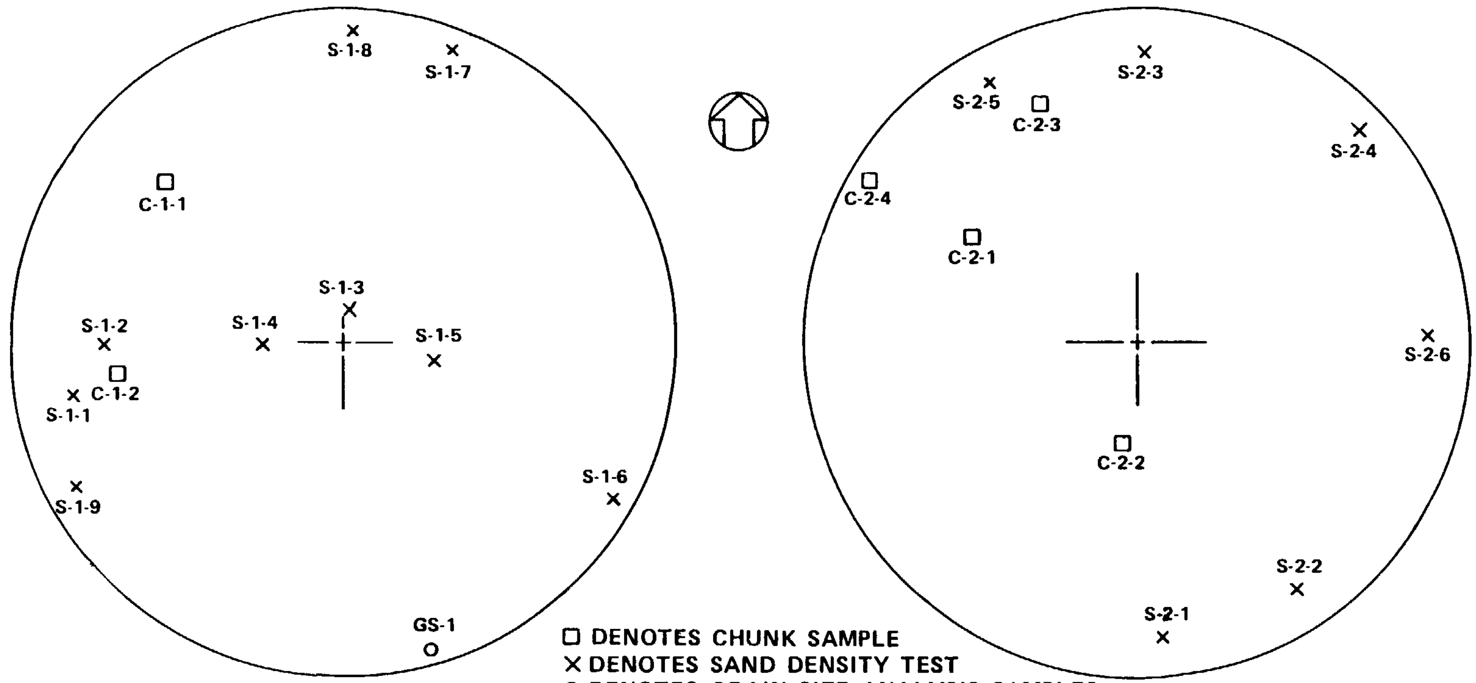


Figure 2.4-8
UNDISTURBED SAMPLE LOCATIONS CONTAINMENT COFFERDAMS



□ DENOTES CHUNK SAMPLE
× DENOTES SAND DENSITY TEST
○ DENOTES GRAIN SIZE ANALYSIS SAMPLES

COFFERDAM NO. 1

SAND DENSITY TESTS

NO.	ELEV.	SAND MEMBER
S-1-1	–13.2	A
S-1-2	–13	A
S-1-3	–24	B
S-1-4	–27	B
S-1-5	–27	B
S-1-6	–32.1	B
S-1-7	–35.6	B
S-1-8	–34.6	B
S-1-9	–29.0	B

CHUNK SAMPLES

C-1-1 ELEV. –14
C-1-2 ELEV. –16

GRAIN SIZE ANALYSIS SAMPLES

G-S-1, –25.6' to –36.6', 12 SAMPLES

COFFERDAM NO. 2

SAND DENSITY TESTS

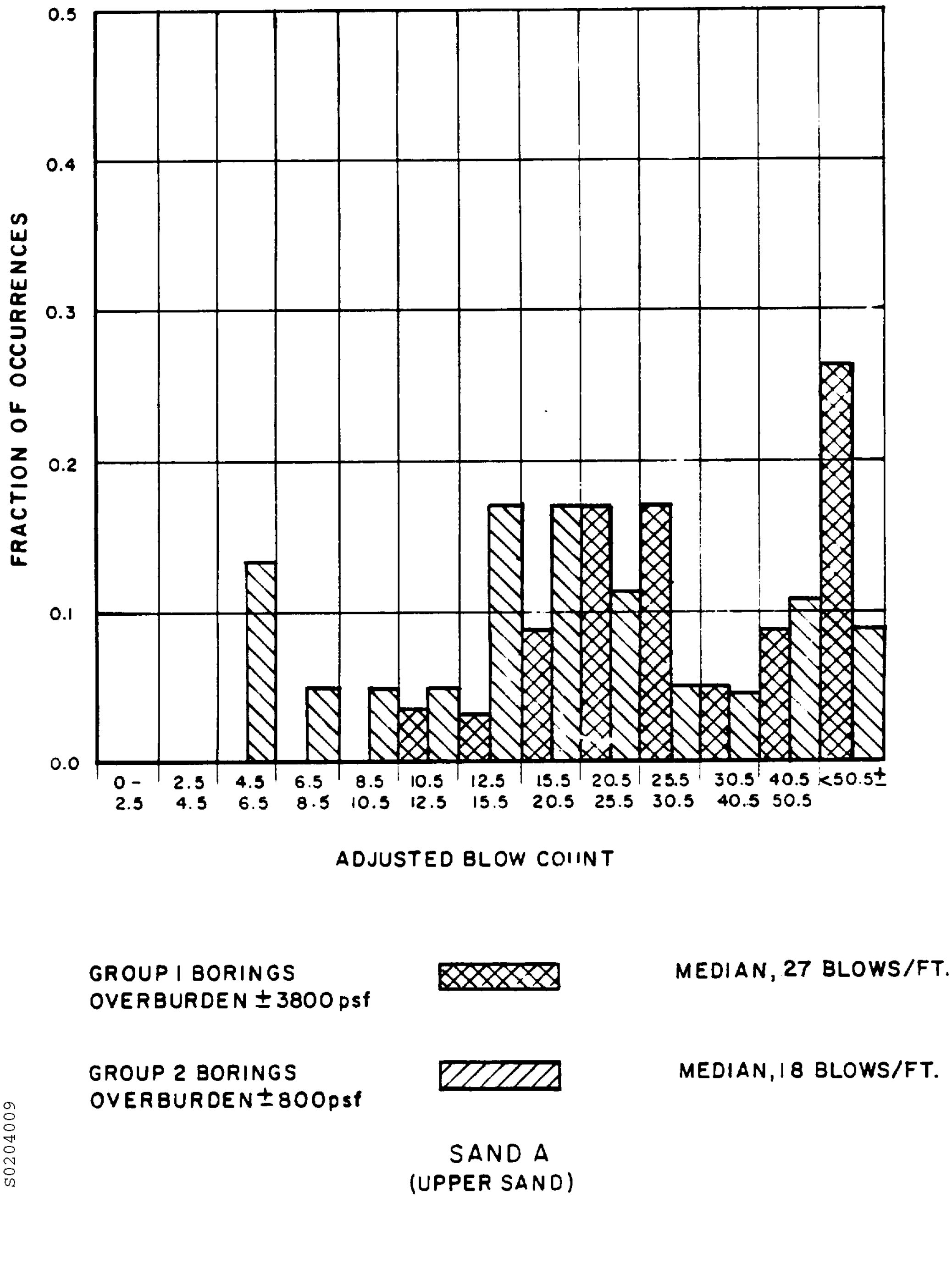
NO.	ELEV.	SAND MEMBER
S-2-1	–2	A
S-2-2	+3	A
S-2-3	–3	A
S-2-4	+1	A
S-2-5	–2	A
S-2-6	+1	A

CHUNK SAMPLES

C-2-1	ELEV. –8.5
C-2-2	–9
C-2-3	–20
C-2-4	–25

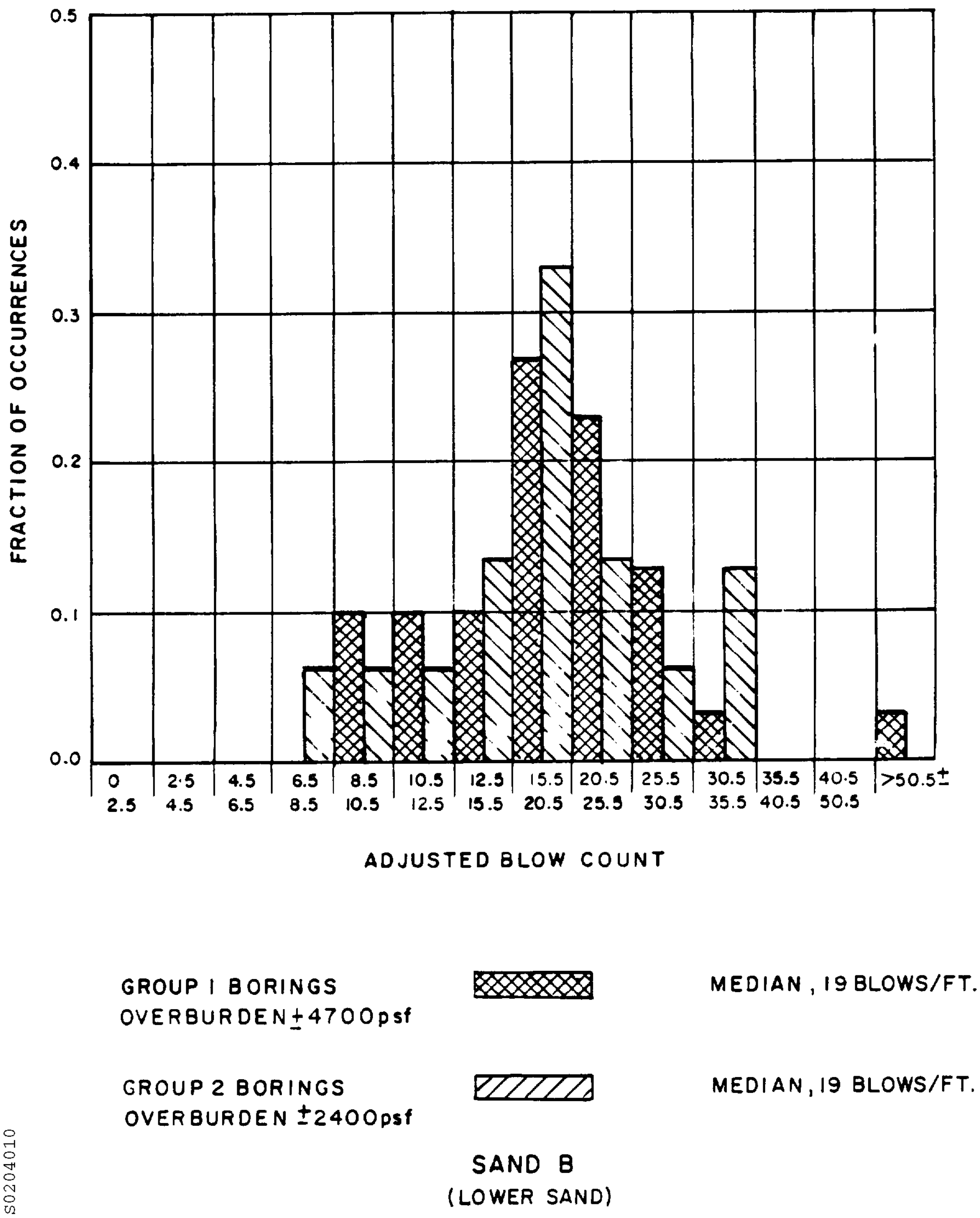
S0204008

Figure 2.4-9
PENETRATION TEST DATA, SAND A



S0204009

Figure 2.4-10
PENETRATION TEST DATA, SAND B



S0204010

Figure 2.4-11
VERTICAL EFFECTIVE STRESS AT SAMPLE LOCATION

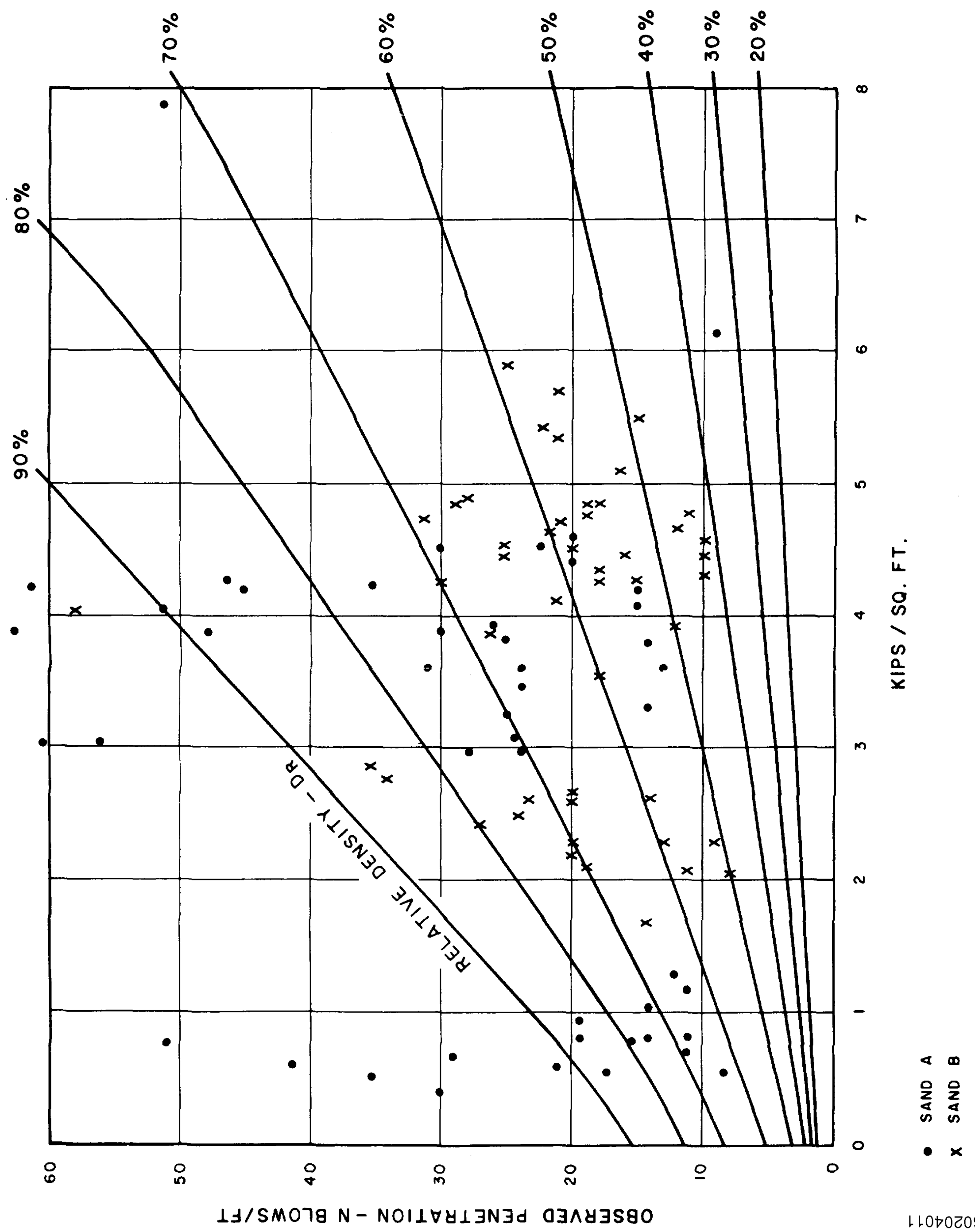
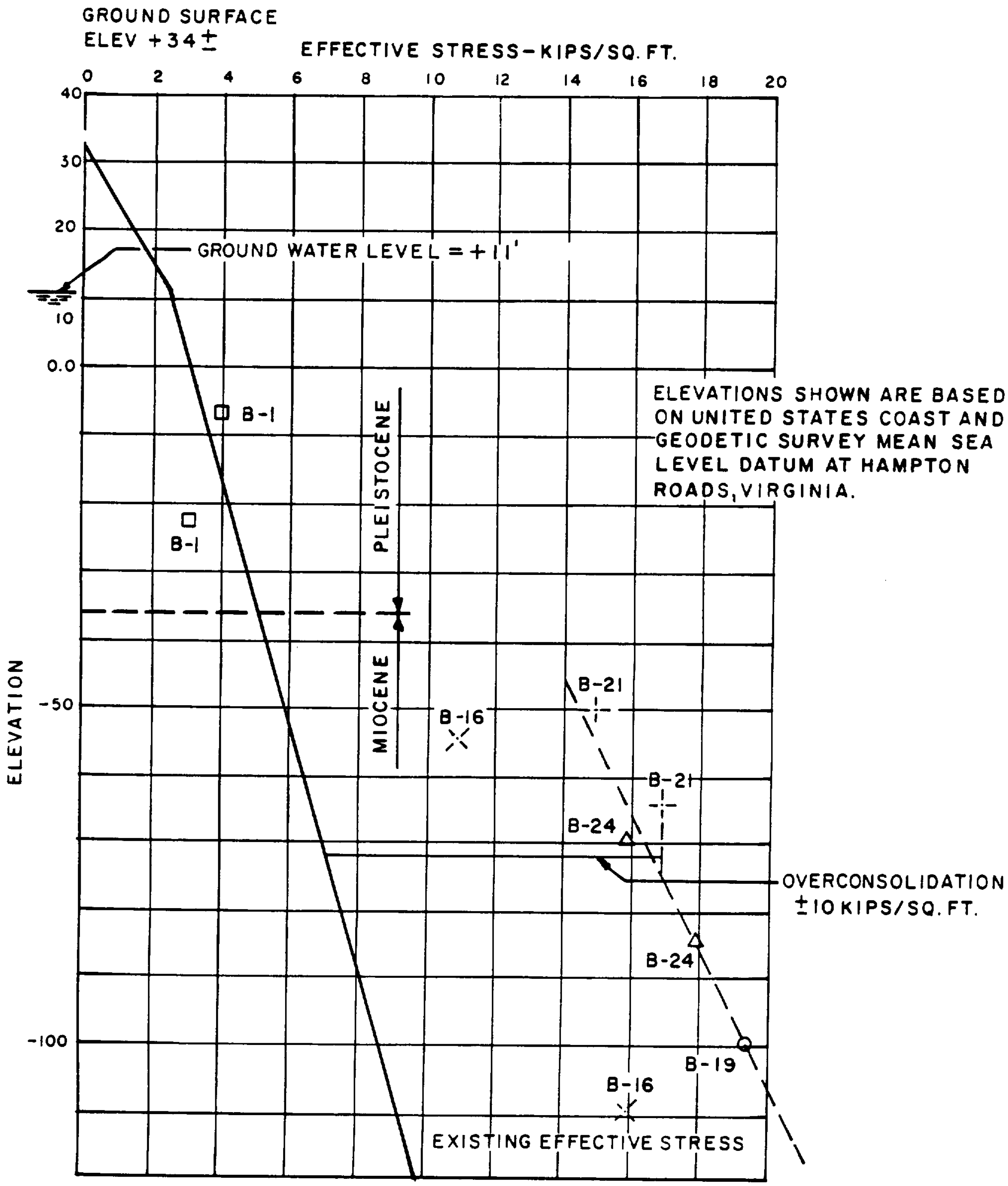


Figure 2.4-12
PRECONSOLIDATION LOADS



FOR LOCATION OF BORINGS,
SEE FIG. 2.4-2

S0204012

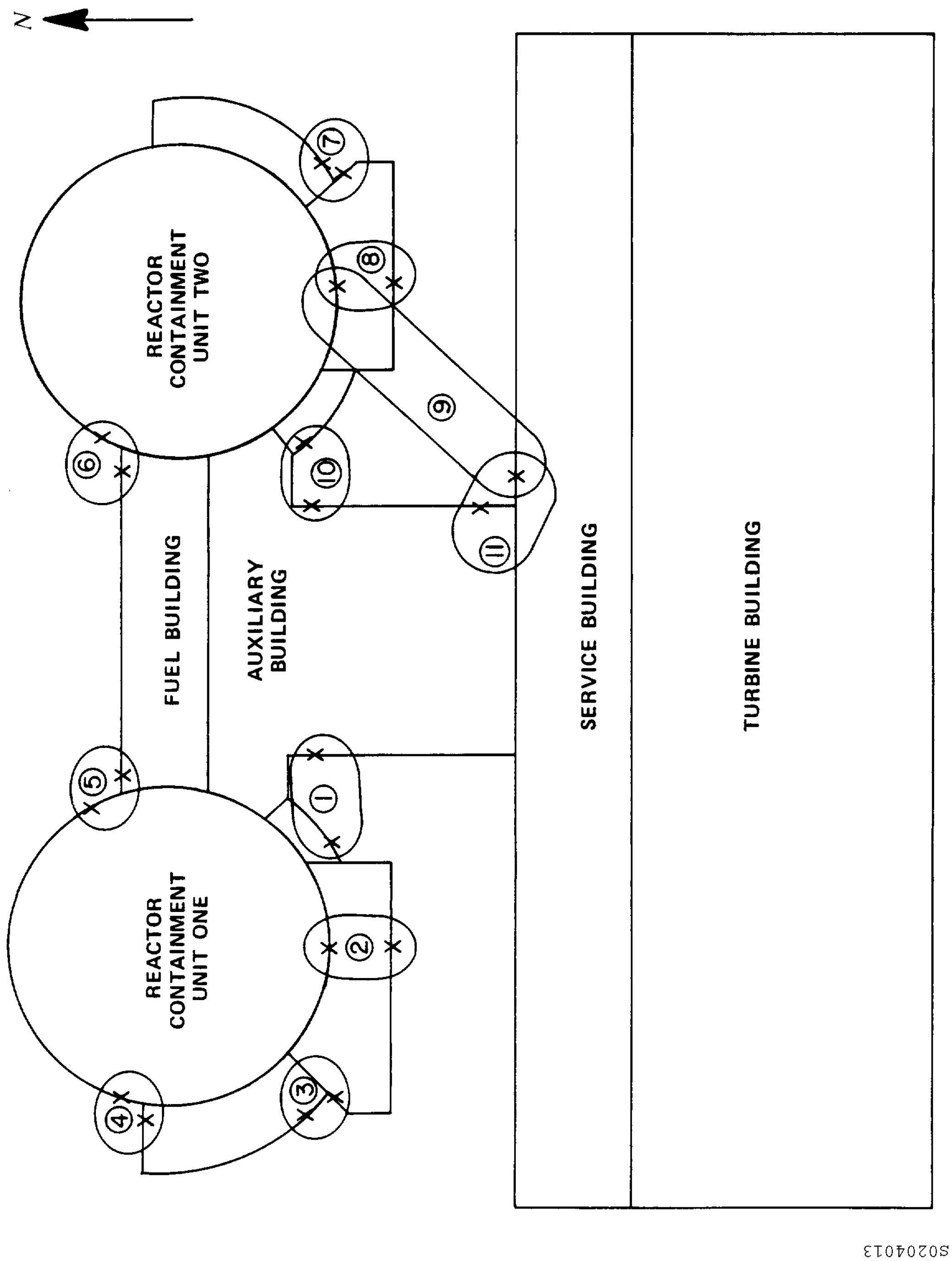


Figure 2.4-13
INTERFACE LOCATIONS

Figure 2.4-14
PIEZOMETRIC READINGS - 1970

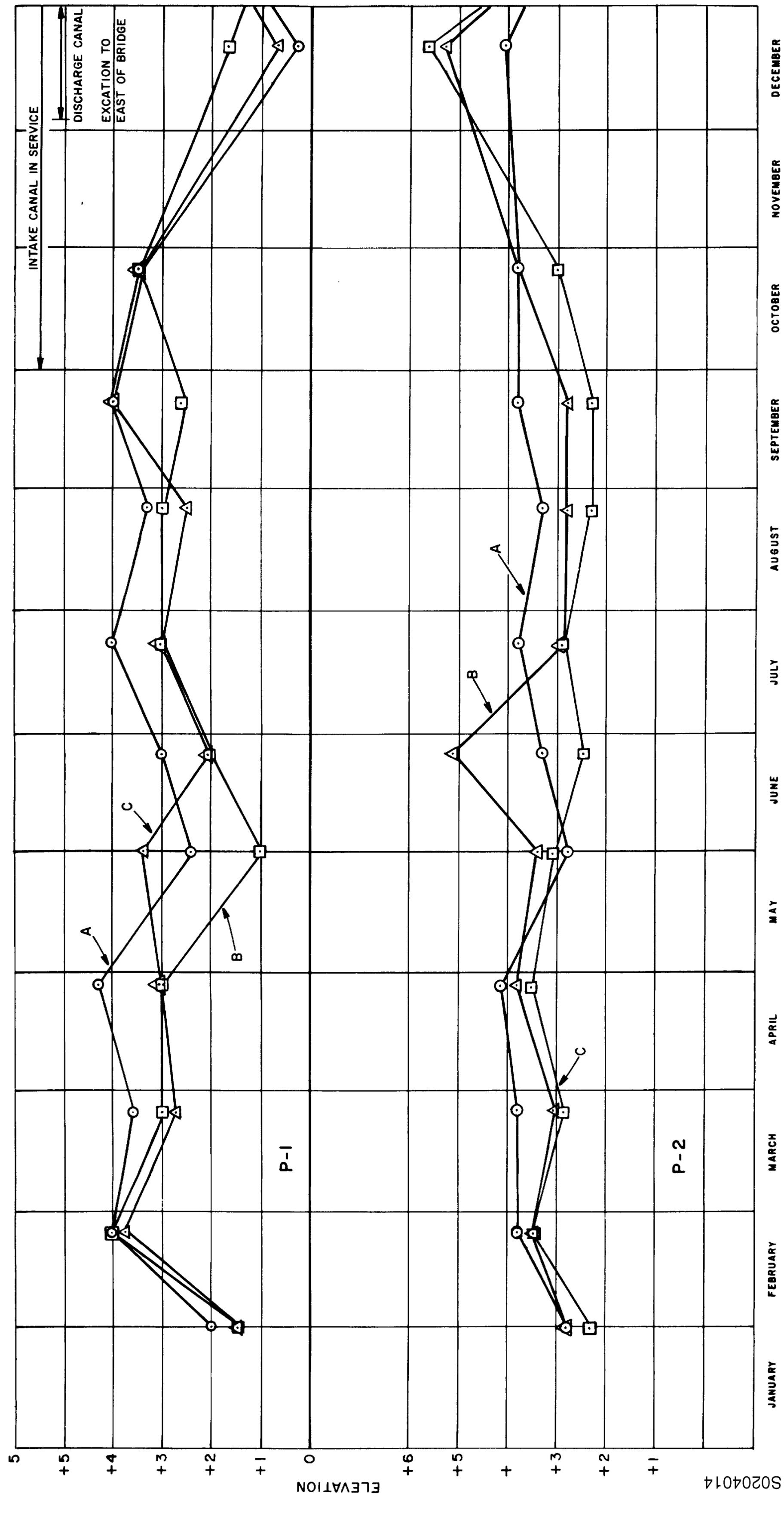


Figure 2.4-15
PIEZOMETRIC READINGS - 1970

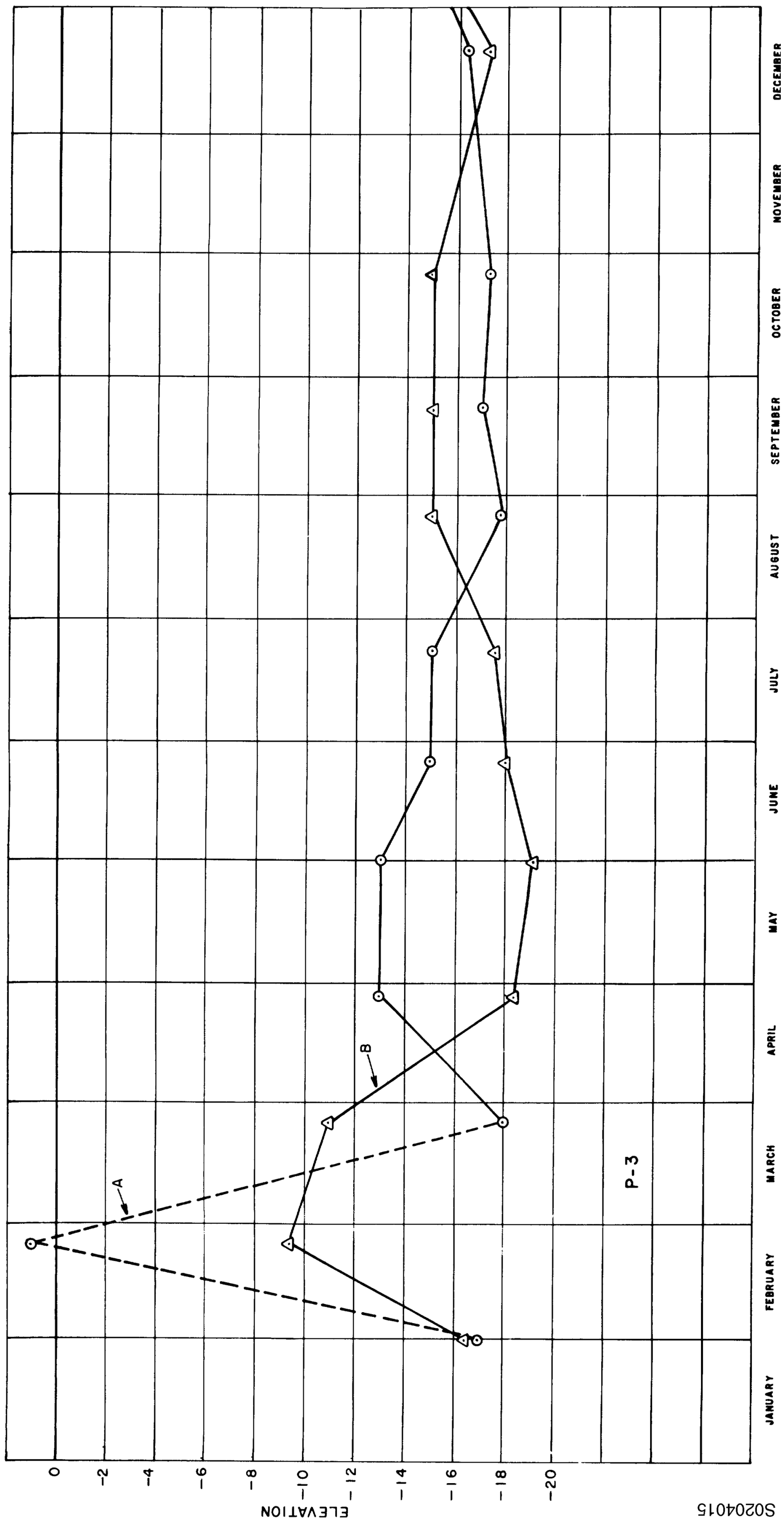
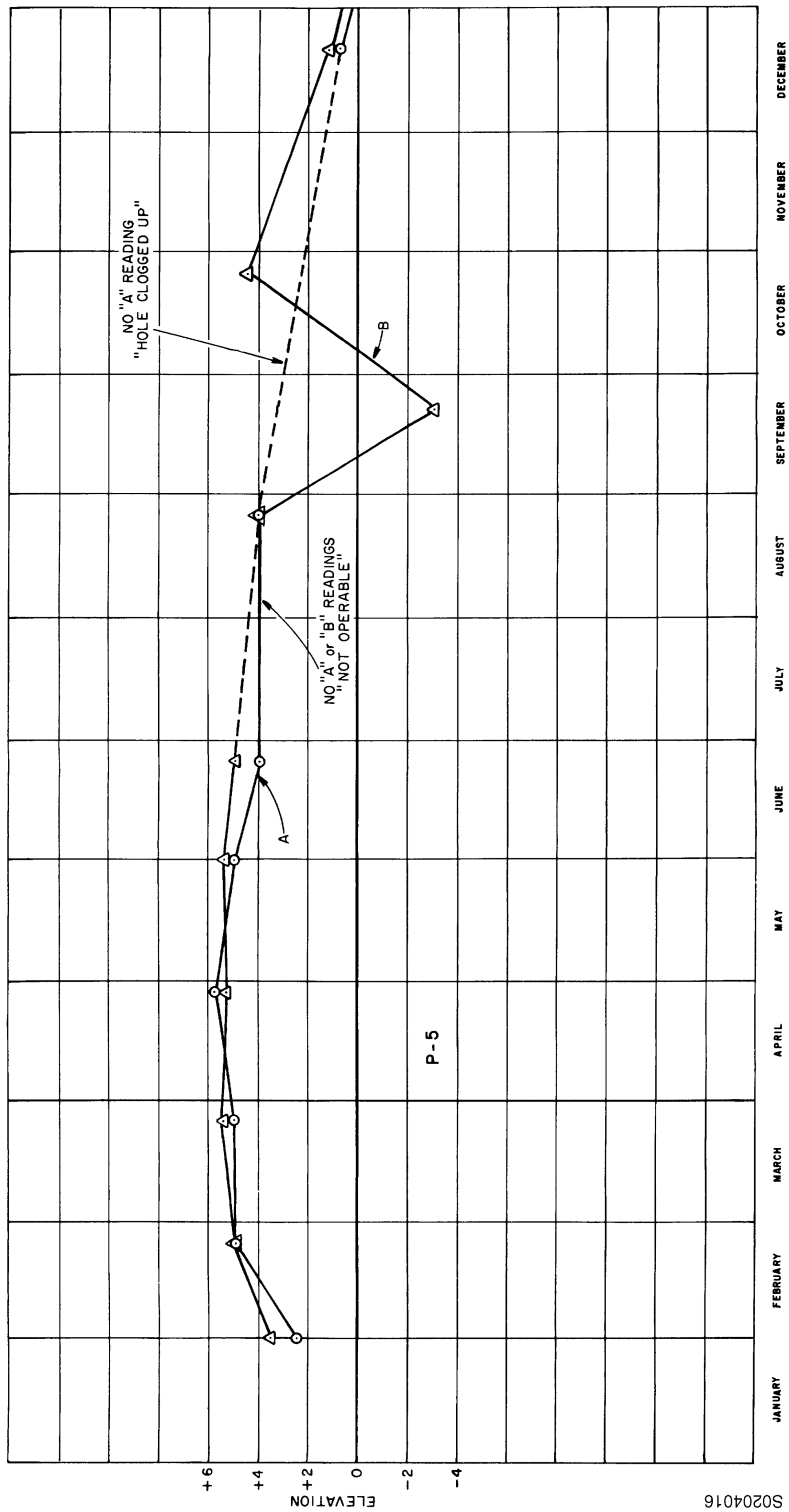


Figure 2.4-16
PIEZOMETRIC READINGS - 1970



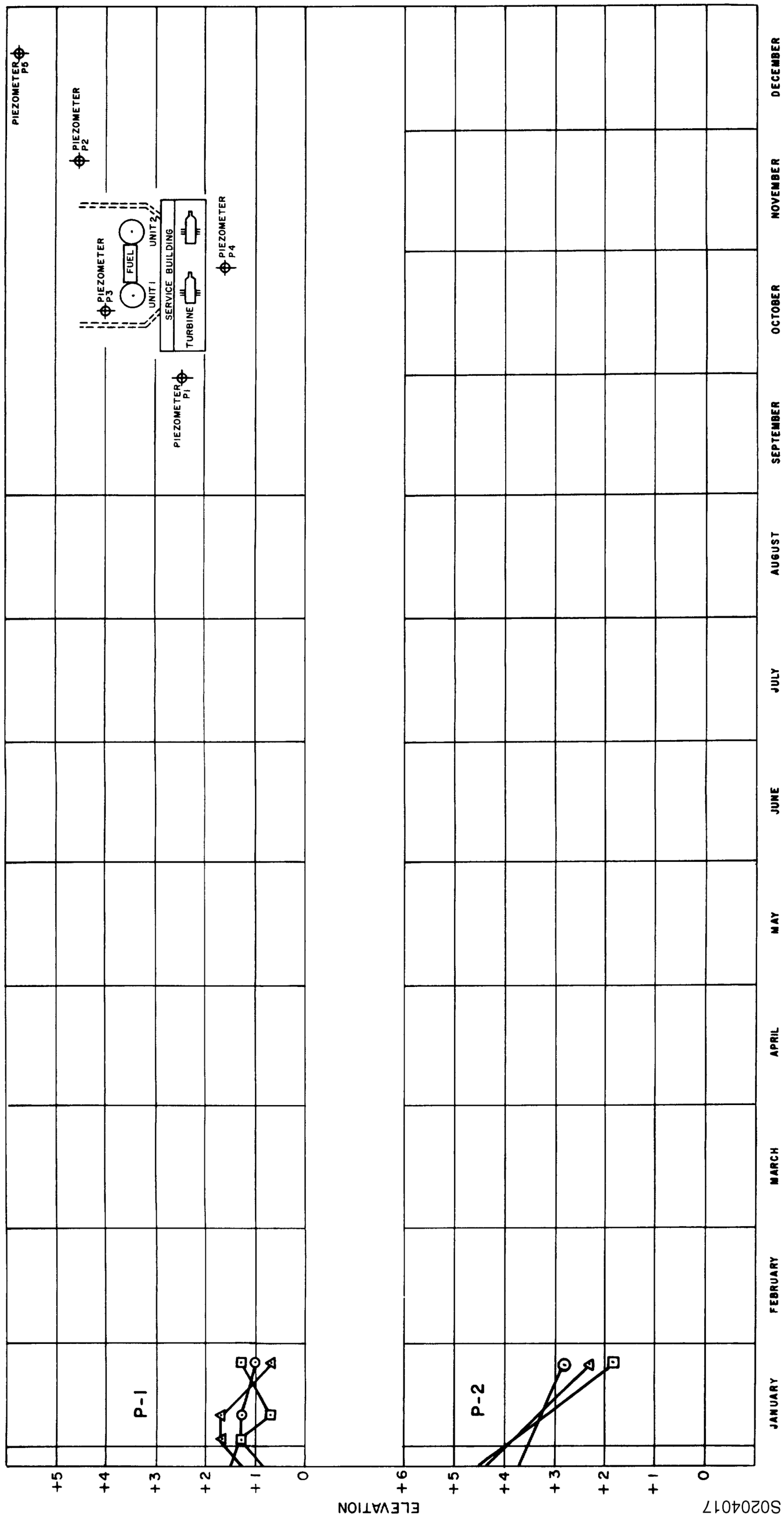


Figure 2.4-17
PIEZOMETRIC READINGS - 1971

Figure 2.4-18
PIEZOMETRIC READINGS - 1971

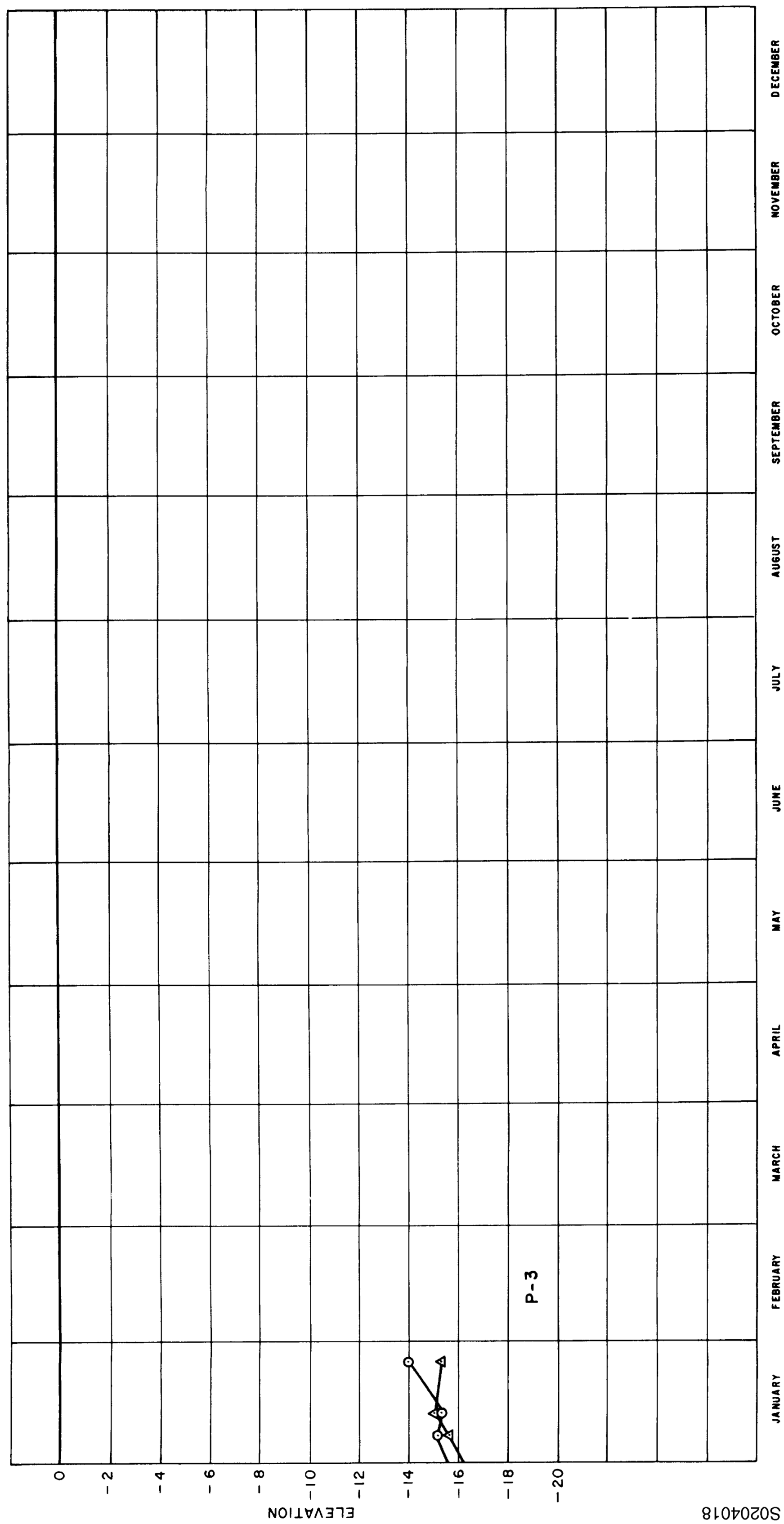


Figure 2.4-19
PIEZOMETRIC READINGS - 1971

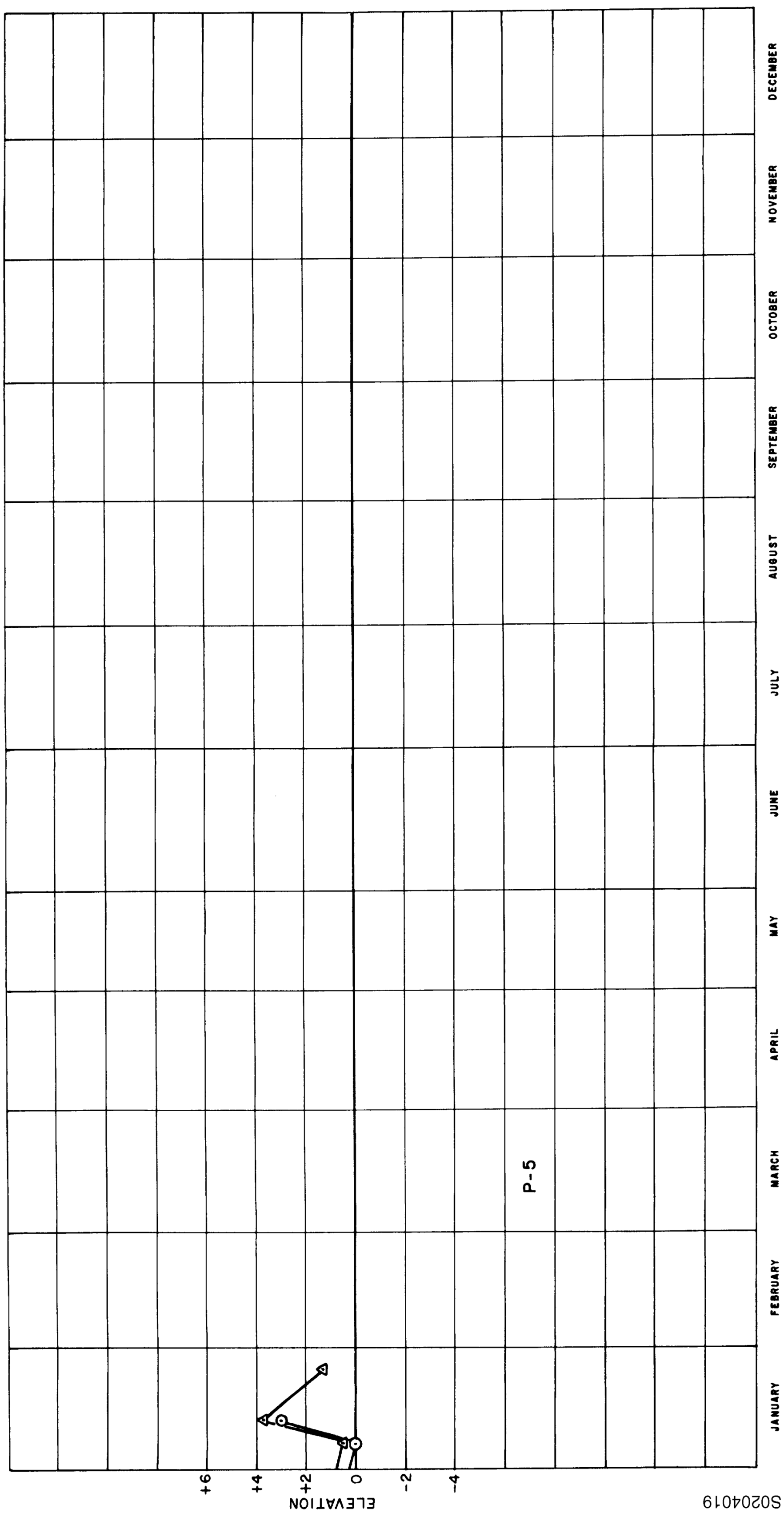


Figure 2.4-20
PRECIPITATION DATA VICINITY OF SURRY STATION

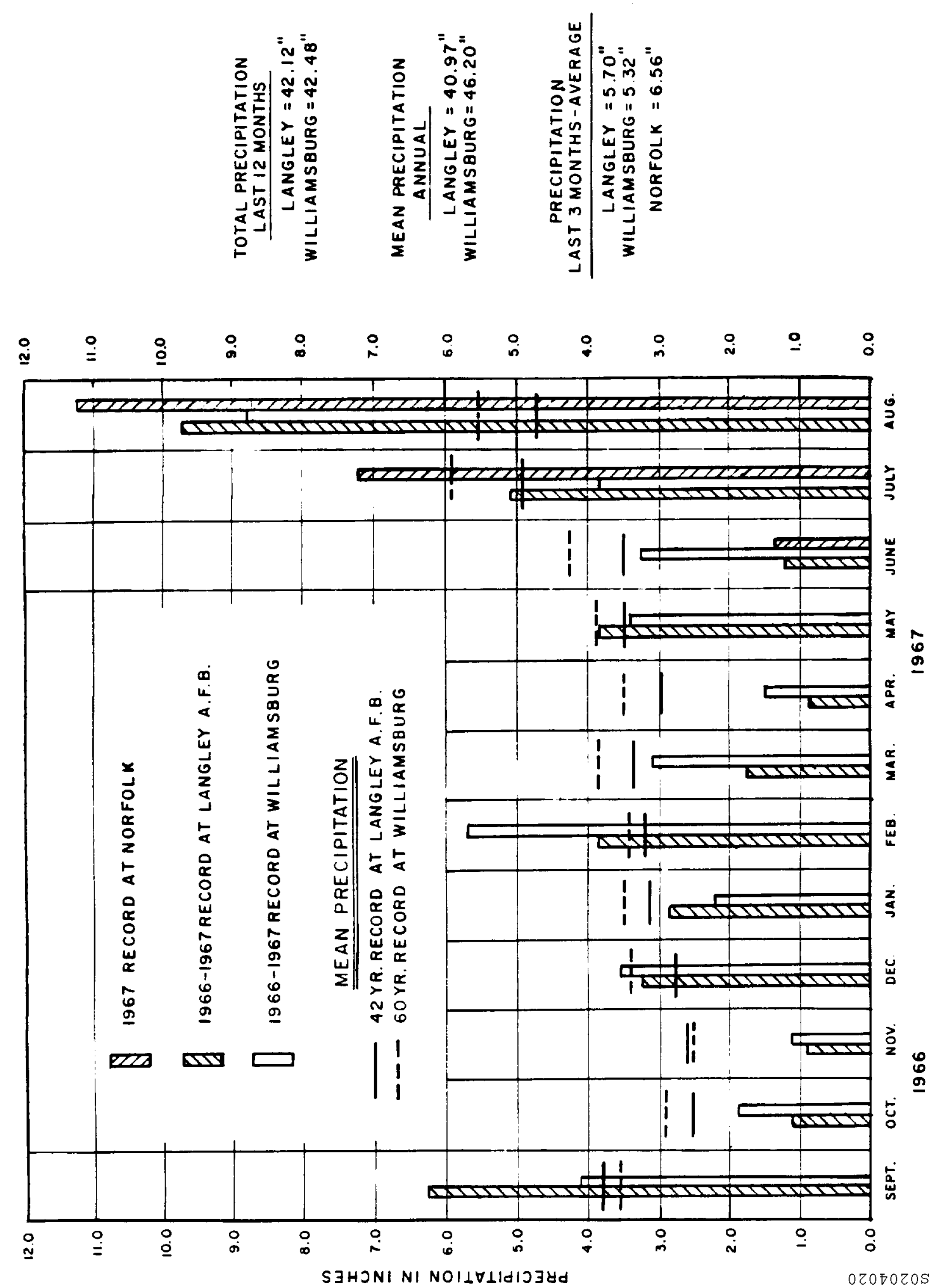


Figure 2.4-21
GROUND MOTION DUE TO EARTHQUAKE

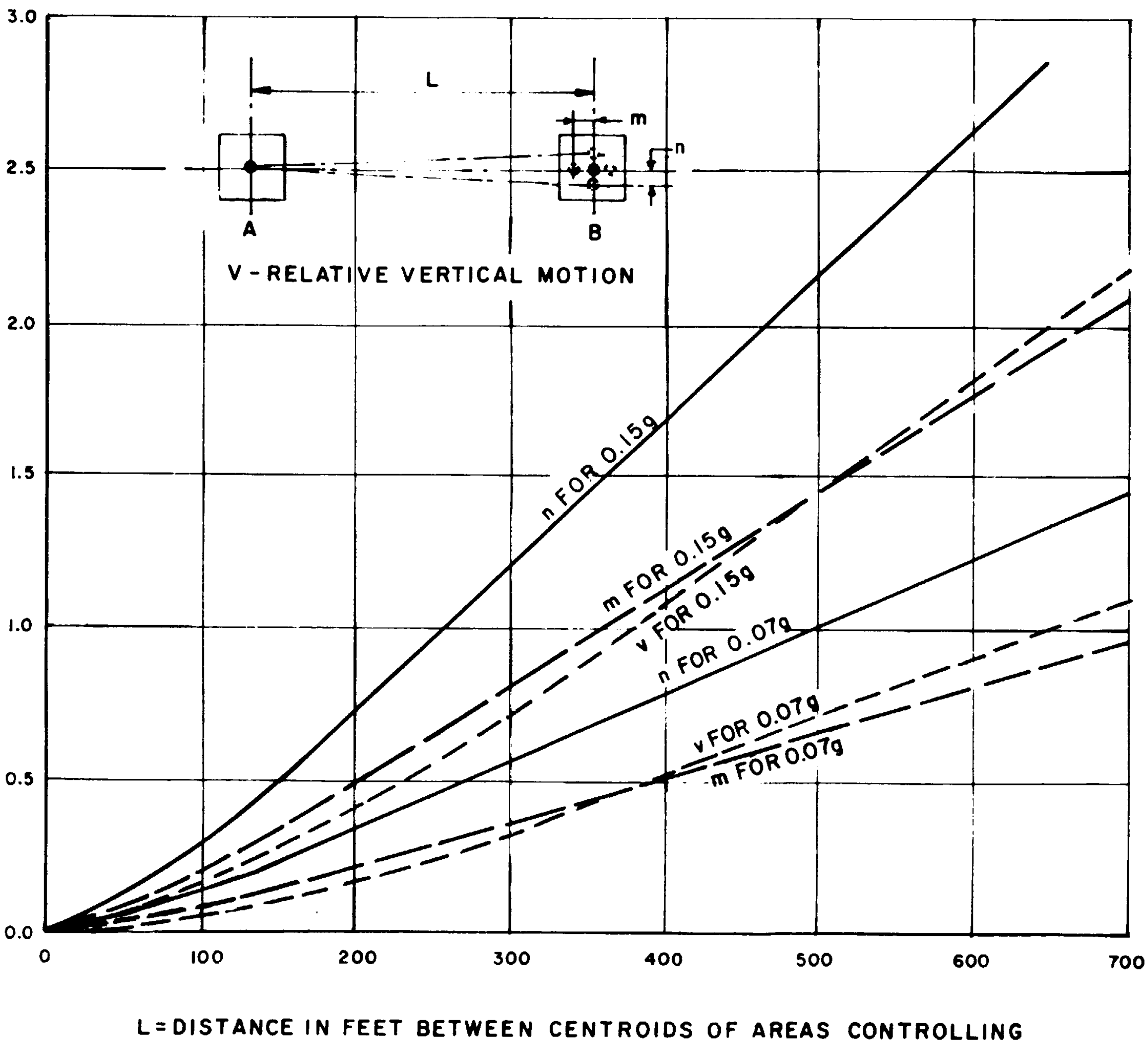
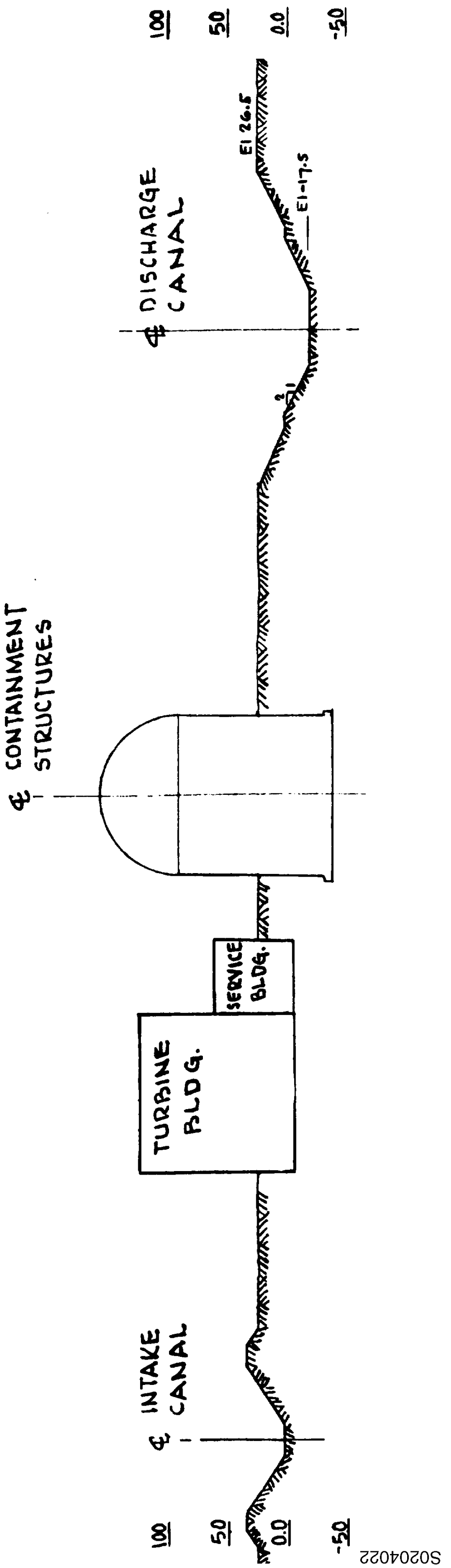


Figure 2.4-22
NORTH-SOUTH SECTION THROUGH SURRY UNIT 2



2.5 SEISMOLOGY

2.5.1 General

Site engineering seismology studies were performed to:

1. Evaluate the seismicity of the area.
2. Select the operating-basis earthquake (OBE) and design-basis earthquake (DBE) conditions.

A comprehensive description of the region seismicity (Reference 1) has been prepared, and a brief description of the seismic history of the region is included herein to assist in reviewing the seismicity of the site area.

2.5.2 Tectonics

The tectonics of the region are largely dependent on the study of the Appalachian Highlands, especially that of the Blue Ridge and Piedmont provinces. The appearance of the Coastal Plain is a relatively recent event and is related to the late tectonic history of the Piedmont. Coastal Plain tectonics will be introduced after a basic discussion of the early tectonics of the Appalachian Highlands which form the structural basis for the region. The tectonic features of the region are shown on Figure 2.5-1.

The Appalachian Highlands form a continuous mountain chain extending the length of the eastern North American shoreline from central Alabama to Newfoundland. The tectonic trends (fold axis, faults, foliation, structural pattern, igneous intrusives, etc.) or the Highlands, though locally irregular, generally are remarkably even. They are parallel to one another, and parallel to the general northeast-southwest trend of the mountain chain. Taken broadly, the chain is a series of arcs convex to the northwest. The central arc extends from New York City to southern Virginia (approximately 400 miles), and delineates the region known as the central Appalachians. Most of the site region is within this area. To the south is another arc which extends from southern Virginia to central Alabama (approximately 500 miles), and delineates the region known as southern Appalachians. It includes the most southern parts of the site region.

One of the most prominent structural features of the region is the western edge of the Blue Ridge province, known as the tectonic front (Reference 2). It marks the boundary between the highly deformed and metamorphosed crystalline rocks of the Blue Ridge and Piedmont provinces to the east and unmetamorphosed sedimentary rocks of the Valley and Ridge and Appalachian Plateau provinces to the west. Through most of central and northern Virginia there is no marked evidence of major faulting along the front. South of about latitude 36 degrees North the front is continuously faulted for the entire length of the southern Appalachians, 500 miles. From latitude 36 degrees to the Roanoke area the faulting is high-angle reverse. South of Roanoke it abruptly changes character to systems or low-angle thrust sheets. Some of these thrust faults have throws as great as 10 miles to the northwest. The closest approach of this faulted front to the site is 130 miles to the west.

Immediately northwest of the tectonic front is the Valley and Ridge province and the Appalachian Plateau. These are separated by the Allegheny front, which marks the sharp transition between the intensely folded and faulted, rocks of the Valley and Ridge and the gently folded, and only locally-faulted, plateau rocks. The Allegheny front is approximately 200 miles from the site area.

Within the central Appalachian region, the Valley and Ridge province is structurally dominated by large, parallel, northeast-southwest trending fold systems rather than by faults as in the southern Appalachians. The main fold belts are the Massanutten synclinorium, Shenandoah synclinorium, and Nittany anticlinorium, approximately 140, 165 and 180 miles northwest of the site area, respectively. Two major fault zones also traverse the Valley and Ridge province in this area, the Staunton fault and the Little North Mountain fault. The Staunton fault is approximately 145 miles west-northwest of the site area and trends northeast to southwest, parallel with the regional structural fabric. It is a high-angle reverse fault along its 95-mile length through the central Appalachians. Near Roanoke, it joins the Catawba-Pulaski fault system which are low-angle thrust faults. Further northwest, about 150 miles from the site, is the Little North Mountain fault zone. This zone trends parallel to regional structure for a total length of about 190 miles and is a high-angle reverse fault, dipping southeast at its surface exposures.

All of the above mentioned tectonic features of the Valley and Ridge Province, regardless of their tectonic origin, date back to Paleozoic age with the most intense activity during the Allegheny orogeny, 230 to 260 million years ago. No active surface faulting is known in this area.

East of the tectonic front are the Blue Ridge and Piedmont provinces. The Blue Ridge province has been structurally folded and faulted into a complex anticlinorium. Through the area of study it is composed of metamorphosed Precambrian age, 1100 million-year-old gneiss with some small areas of younger Precambrian or Cambrian schists. Small faults are common throughout the anticlinorium. However, as shown on Figure 2.5-1, there is one large fault zone about 55 miles long trending northeast, parallel with the regional structure, just west of Charlottesville, Virginia. The faulting is high-angle reverse. It is about 120 miles northwest of the site. All of the above-mentioned tectonic features of the Blue Ridge are of Paleozoic age, with the most intense activity during the Taconic orogeny, 450 to 500 million years ago. No active surface faulting is known in this area.

Further east is the Piedmont province. It is primarily composed of early-to mid-Paleozoic sedimentary and igneous rocks that have been metamorphosed into schist, gneiss, and granitic gneisses. Within the older crystalline rocks are basins of unmetamorphosed sediments of Triassic age, 180+ million years old.

The boundary between the older Precambrian rocks of the Blue Ridge and the Piedmont does not appear to contain major faulting within the study area. In southern Virginia this transition is marked by a major fold belt known as the James River synclinorium which is faulted along the northwest. The synclinorium is 110 miles west of the site.

In Northern Virginia, the eastern Blue Ridge boundary is slowly approached by the western fault system of the Culpeper Triassic Basin until, near the Maryland border, it intersects the Blue Ridge basement rock complex. This Triassic basin border fault, as well as all other known Triassic basin border faults, is a high-angle normal fault.

It is downfaulted on the east side with a vertical displacement of about 10,000 feet, a magnitude common to most large Triassic fault basins. The fault is part of a system that extends a distance of about 125 miles to the northeast and joints the Gettysburg and Newark-Delaware basin system, which are out of the area of study. It is about 110 miles northwest of the site. Other Triassic faults and associated sedimentary basins, which are of common origin and character, located within the study area are:

1. A Triassic basin just south of Charlottesville, Virginia, approximately 110 miles west of the site. It is about 25 miles long and faulted on both the east and west sides.
2. Dan River basin, approximately 120 miles west of the site. It is about 110 miles long and faulted on the west side.
3. Central Triassic faulting, located south of Arvonia syncline approximately 95 miles west of the site. The faulting extends intermittently for 70 miles along a northeast trend. The small basins formed are faulted on the west side.
4. Richmond basin, approximately 55 miles west of the site. It is the closest known faulting to the site area. The basin trends north-northeast and away from the site area. It appears to be about 65 miles long and faulted on both the east and west sides.
5. Deep River-Durham basin approximately 120 miles southwest of the site area. It is faulted primarily on the east side for about 160 miles.
6. Recent aeromagnetic data indicate the possibility of additional Triassic basin faulting east of the Baltimore area as shown on Figure 2.5-1.

Other Piedmont tectonic structures are of Paleozoic age, most of which are contemporaneous with the intense metamorphic and tectonic activity related to the Taconic and Acadian orogenies of 450 and 360 million years ago. The major fold belts include the James River synclinorium, previously mentioned, the Hardware anticline, the Arvonia-Columbia-Quantico syncline trend, the Virginia synclinorium and the Wake-Warren anticlinorium, about 110 miles west, 105 miles northwest, 90 miles northwest, and 80 miles southwest of the site, respectively. Faulting, though common on a localized scale throughout the Piedmont, is not prominent on a regional scale. Aeromagnetic data (Reference 3) indicate a major Paleozoic age lineament through central Virginia. It trends northeast across the State of Virginia and is about 100 miles northwest of the site. The lineament has not been identified by field mapping, but is inferred to be a metamorphosed and recrystallized fault trend (Reference 4).

Additional Paleozoic faulting is associated with the northwest side of the James River synclinorium, about 12 miles west of the site, and two faults associated with the Baltimore, Maryland, area 140 miles north of the site. The James River synclinorium faults are westerly thrust faults, about 50 miles long, trending northeast. The Baltimore area faults trend northeast to north, are normal faults, and extend for a length of about 10 miles.

East of the Piedmont is the Atlantic Coastal Plain. The Coastal Plain is essentially an irregular, thick, dissected, eastward-facing wedge of unconsolidated to semi-consolidated sediments. The basement of this wedge consists of Paleozoic-age Piedmont-type rocks. They are largely igneous and low- to high-grade metamorphic rocks.

The site is located in the Coastal Plain, Physiographic Province. In Virginia, the province is bounded on the east by the Atlantic Ocean and on the west by the Fall Line and the Piedmont Physiographic Province. The crystalline basement rock crops out near the Fall Zone about 50 miles west of the site. From the Fall Zone, the basement surface slopes gently to the southeast, and is overlain by Cretaceous and Tertiary sediments that are about 1300 feet thick at the site.

The Coastal Plain sediments effectively mask the crystalline basement rock so that no faulting can be identified in the area. However, the available regional data and the geologic studies at the site indicate that the overlying Cretaceous and Tertiary sediments are essentially underformed in the site area. The absence of folding and faulting in the exposed sedimentary strata of the Coastal Plain in the vicinity of the site indicates that any displacements along possible unknown faults have been negligible.

2.5.3 Seismicity

2.5.3.1 **Earthquake History**

The site is situated in a region that has experienced only infrequent minor earthquake activity. The closest major earthquakes to the site, the Charleston earthquakes of 1886, had their epicenters about 350 miles southwest of the site. No shock within 50 miles of the site has been large enough to cause structural damage. Since the region has been populated for over 300 years, it is probable that any earthquake of moderate intensity, VI or greater, would have been reported during this period. It is very likely that all earthquakes with intensities of V or greater within the last 200 years have been reported.

The first record of earthquake occurrence in the vicinity of the site was made in the late Eighteenth century. Since then, only about eight earthquakes with epicentral intensities of Modified Mercalli V or greater have been reported within 100 miles of the site. All intensity values in this report refer to the Modified Mercalli Scale as abridged in 1956 by Richter (Table 2.5-1). The intensity scale is a means of indicating the relative size of an earthquake in terms of its perceptible effects. Modified Mercalli intensity, where abbreviated, is designated as "MM."

Forty-four earthquakes of intensity V (MM) or greater have been reported within 200 miles of the site from 1774 through September 1995. The largest of these are of epicentral intensity VIII

(MM). There has been no resultant structural damage at the site and the associated acceleration is estimated to have been less than 0.05g.

Listed in Table 2.5-2 and shown in Figure 2.5-2 are all known earthquakes from 1774 through September 1995 with epicentral locations within a 50-mile radius of the site and all earthquakes of intensity V (MM) or greater with epicentral locations within 200 miles of the site. There are no known epicentral locations within a 30-mile radius of the site. The historical earthquakes of the region that are believed to have been felt at the site (Reference 5) are discussed in greater detail in Reference 6.

Most of the nearest recorded earthquakes in the region have occurred in the Piedmont Province, west of the Fall Zone. The closest approach of the Fall Zone to the site is about 50 miles. These shocks are generally related to known faults in the Piedmont rocks. Several shocks have occurred in the Richmond, Virginia, area, which is on the Fall Zone. This activity along the Fall Zone is consistent with similar occurrences both to the north and south of the site area.

2.5.3.2 Correlation of Epicenters with Geologic Structures

Relative to the site, the most significant earthquakes and associated seismotectonic zones are believed to be the following:

1. 1897 Giles County, Virginia; intensity VIII (MM) - associated with the Appalachian seismic zone.
2. 1875 Richmond, Virginia; intensity VII (MM) - associated with the central Virginia seismic zone.
3. 1866 Charleston, South Carolina; intensity X (MM) - associated with the Charleston seismic area.

Giles County, Virginia

The 1887 earthquake of Giles County, Virginia, of epicentral intensity VIII (MM), is part of what has been described by Bollinger (Reference 7) as the southern Appalachian seismic zone, and its northern extension the northern Virginia-Maryland seismic zone. The zone is characterized by a general northeast-southwest alignment of the epicenters of the larger shocks in the site region. The zone is roughly coincident with tectonic features of the Blue Ridge and the eastern side of the Valley and Ridge provinces. It is indicative of continued deep-seated crustal adjustments along zones of intense ancient tectonic deformations. The latest intense period of major deformation was the Allegheny orogeny, approximately 230 to 260 million years ago. There is no evidence of active surface faulting along this trend today.

Richmond, Virginia

The Richmond area is the eastern-most extension of the central Virginia seismic zone described by Bollinger (References 8 & 9).

The central Virginia seismic zone is a relatively narrow, isolated zone of activity, offset from the Appalachian seismic zone and located in the Piedmont province, oblique to the northeast-southwest structural grain. This zone includes an east-west elongate cluster of low to moderate seismic activity. It extends from Richmond, Virginia, to the edge of the Blue Ridge province. It covers a relatively small area of about 16,500 square miles (Reference 9) and appears to be related to deep seismic activity in the vicinity of Triassic faulting.

The historical record of the region attests to the areal extent of the zone as described above. The historical record is over 200 years old within a relatively well populated area. Therefore, shocks of intensity V (MM) and greater would have been recorded by the local populace. Bollinger (Reference 9) has worked out the theoretical earthquake recurrence ratio for different levels of earthquake intensity for the eastern United States. For the large earthquake intensities the recurrence rates are VIII (MM) (51 years), and VII (MM) (13 years) and much less for the lower intensities.

Charleston, South Carolina

The seismic history of the southeastern United States is dominated by earthquake activity in the Charleston area. Charleston is about 350 miles south of the site and represents the closest zone of major earthquake activity. Of the 850 earthquakes reported for the southeastern United States in the period of 1754 to 1971, 402 have been in the Charleston area. All of these shocks have been localized to a very limited area around Charleston. Based on the character of the epicentral record and the high frequency of shocks consistently within a small area, the Charleston area is treated as a seismotectonic province by itself. The largest shock that occurred here was the shock of epicentral intensity X (MM) on August 31, 1886. It was felt at the site with an intensity V (MM).

Other Events

Another significant series of earthquakes in the Coastal Plain occurred near the northern New Jersey coast about 250 miles northwest of the Surry site, in 1927. The maximum reported epicentral intensity of these earthquakes was VII. Three shocks were felt over an area of about 3000 square miles, from Sandy Hook to Toms River, New Jersey. Highest intensities were felt from Asbury Park to Long Branch, where several chimneys fell, plaster cracked, and articles were thrown from shelves. This shock has not been related to any known geologic feature, although there is some suggestion that it could be related to possible geologic structures associated with the Hudson River Valley to the north.

There have been small shocks in the Coastal Plain closer to the site. Few of these earthquakes caused any structural damage, and they are of interest only in that they indicate the possible presence of unidentified faulting in the basement rock beneath the Coastal Plain.

The closest reported earthquakes to the site were two small shocks felt only at Suffolk, Virginia, on April 19, 1918. It is possible that these shocks were not of tectonic origin; however, if they were valid earthquakes, they could indicate the presence of minor faulting in the basement rock close to the site.

2.5.3.3 **Identification of Active Faults**

Based on the studies listed below, there is no known evidence for active faulting in the vicinity of the site (Reference 6).

1. Photo interpretation - Airphotos, topographic maps, and Earth Resources Observing Satellite (EROS) photos of the site area were examined. No evidence of surface rupture, surface warping, or offset of geomorphic features possibly indicative of faulting was found.
2. Aeromagnetic studies - Aeromagnetic mapping of the site and region was examined. There was no aeromagnetic feature indicative of faulting in the vicinity of the site. Some distant, regional features indicative of bedrock faulting were found. They are shown on Figure 2.5-1.
3. No macroseismic activity has been detected in the site area. The closest epicentral location is about 30 miles southeast of the site. It is of intensity III (MM) and not correlative with any known surface feature.
4. Detailed geologic mapping of the site area and vicinity in References 10, 11 and 12 show no evidence of surface or active faulting.
5. Borings drilled at the site indicate continuity of strata and are indicative of no significant (5 feet) fault displacements, dating back at least 2 million years as shown by the top of the erosional Micocene surface.

Regionally, there is no known active surface faulting. Surface expression in the form of active fault scarps have not been observed. Seismic activity within the region is believed to be due to deep-seated crustal adjustments along previous zones of structural deformation and weakness.

2.5.4 Seismic Design

2.5.4.1 **Operating-Basis Earthquake (OBE)**

The number of cycles of significant motion in a number of earthquake records has been analyzed. Observation indicates maximum acceleration occurs as a single peak (Reference 13) (never appears more than once). Table 2.5-3 shows the number of cycles of motion in which an acceleration of half the peak is equalled or exceeded in a number of earthquake records. These were taken from accelerograms of the earthquakes listed. A decrease in acceleration to one-half the peak value corresponds approximately to a decrease of one order of intensity on the Modified Mercalli scale and, as a result, conservatively defines the number of cycles of significant motion.

For this site, the operating-basis earthquake is most probably characterized as a sharp, short local earthquake of Intensity VI or less. As indicated on Table 2.5-3, small, sharp earthquakes of this type, such as Golden Gate '57 or Hollister, showed only a few cycles of significant motion. For the design-basis earthquake, longer duration as well as larger accelerations would be expected. Even for great earthquakes such as El Centro '40 and Taft '52, which were much more intense than anticipated for the design-basis earthquake at Surry, there are only about 10 cycles of significant motion. Use of eight to ten cycles in analyses for the design-basis earthquake is reasonable and conservative.

The number of cycles of significant motion is important in demonstrating that fatigue failure due to stress reversals is not a critical consideration in designing the containment structure. The number of loading cycles is also considered when evaluating the hazard of liquefaction for the design-basis earthquake.

The maximum estimated earthquake intensity at the Surry site is VI (MM). Based on correlations between intensity and peak acceleration (Reference 14), the peak acceleration values for intensity VI would be 0.0425g vertical and 0.066g horizontal. Also, monitoring sites are differentiated by geological classification (soft, intermediate, and hard). The Surry site most closely resembles the soft site condition (i.e., shallow and deep alluvium) as opposed to intermediate (sedimentary rock) or hard (igneous and metamorphic rock). The interpretation of their graph, of acceleration and intensity (Reference 14) indicates that the mean peak ground acceleration in the maximum direction (horizontal) on a soft site is about 65 cm/sec (Reference 2) or less than 0.07g.

On the basis of the seismic history of the area, it does not appear likely that the site will experience earthquake ground motion of more than a few percent of gravity during the economic life of the facility. However, Class I structures and equipment are designed to withstand a maximum horizontal ground acceleration of 7% of gravity. Vertical acceleration is taken as being two-thirds of horizontal, assumed acting simultaneously and in proper phase to be additive to loads or stresses from horizontal motions. It is believed that this magnitude of ground motion would not be exceeded at the site during an earthquake similar to any previously experienced in the area.

2.5.4.2 **Design-Basis Earthquake (DBE)**

For the safe and orderly shutdown of the station, all Class I structures and equipment are designed using a seismic factor equal to the ground acceleration at foundation level that might occur due to the maximum credible earthquake. The design-basis earthquake for this site would be a shock similar to one of the following:

1. The eastern Virginia earthquake of 1875 occurred as close to the site as its related geologic structure. It is estimated that the magnitude, m, of this earthquake was about 5 on the Richter Scale. It is probable that this earthquake was related to Piedmont structure, near the Fall Zone. However, it is impossible to locate precisely the epicenter of this shock from the limited data available. Since the earthquake and a subsequent aftershock were felt in Williamsburg, the epicenter of this shock may have been located east of the Fall Zone, in the

basement rock of the Coastal Plain. Thus, the conservative assumption is made that an epicentral intensity-VI earthquake could conceivably occur in the basement rock associated with some hypothetical geologic structure. The possibility of such an occurrence is believed to be quite remote.

2. The northern New Jersey earthquake of 1927 occurred close to the site. Since this shock occurred in the Coastal Plain and has not been related to any known geologic structure, the conservative assumption is made that it could be related to a hypothetical geological structure in the basement rock near the site. The magnitude, m, of this epicentral intensity-VII earthquake is estimated to have been about 5. Again, the possibility of such an occurrence is quite remote.

Based on the foregoing evaluation, the design-basis earthquake magnitude is very conservatively assumed to be as large as 5 to 5.5 (epicentral intensity-VII shock), originating in the basement rock close to the site. An occurrence of a shock of the same size as the largest of the 1886 Charleston shocks at a distance of 200 miles or so would result in significantly lower accelerations at the site.

2.5.4.3 **Seismicity Measurement**

A seismic sensing and recording system, incorporating three remote triaxial accelerometers, is installed at the Surry Power Station. The system provides data on the frequency, amplitude, and phase relationship of the seismic response of the Unit 1 reactor containment structure, and provides data on the input vibratory ground motion at the site.

System calibration, testing, recording, and playback are accomplished at the recorder unit located in the control room. Two triaxial accelerometers are installed in the Unit 1 reactor containment structure. One instrument is located on the basement floor (Elevation -27 ft. 7 in.) and the other instrument is located on the uppermost floor (Elevation 47 ft. 4 in.). The instruments are oriented so that the corresponding axes of each accelerometer are aligned in the same direction, and are located approximately above each other. They are mounted rigidly to the containment structure, so that the accelerometer records can be related to the containment structure movement, as required by Safety Guide 12, dated March 10, 1971.

The third triaxial accelerometer is installed in the free field accelerometer enclosure, located approximately 8 feet west of the security fence and 8 feet south of the sally port. The instrument enclosure is located on a 24-inch concrete foundation, and will record data on the free-field ground motion.

The system is capable of performing its required functions over the appropriate range of environmental conditions. A maintenance program is provided in accordance with the supplier’s instruction manual.

The recorder unit will begin recording and initiate an alarm in the control room when actuated by the seismic trigger unit located with the free-field accelerometer. Recording will continue until several seconds after the strong motion ground accelerations have decreased below the trigger setting, and this information will be available to the control room operator.

2.5.5 Estimated Ground Acceleration for Design-Basis Earthquake

2.5.5.1 **General**

It is estimated that the maximum horizontal particle acceleration at planned foundation levels at the site, due to the design-basis earthquake, would be no more than about 15% of gravity. The vertical motion is taken to be two-thirds of the horizontal motion, acting simultaneously with it.

This estimate has been arrived at by several procedures. One procedure was to compare the physical characteristics of the Surry site with those at sites where strong motion records are available (for example, Taft and El Centro, California). If the propagation of earthquake wave motion through the soil strata at the Surry site is comparable to other locations, and there is no unusual amplification of motion, especially in the frequency regions of significance to structures, then the available strong motion records can be used in estimating maximum ground acceleration at Surry. This comparison of site conditions was based upon the amplification spectrum.

Another procedure was based upon empirical formulas developed from a study of world earthquake occurrence by Japanese seismologists.

2.5.5.2 **Amplification Spectrum**

The amplification spectrum was developed by computing wave motion through a layered model of the earth's material, from basement rock up through any desired elevation within the overlying soil. In the model, vertically traveling waves were assumed to propagate through a medium in accordance with wave propagation theory for that medium, assuming any desired degree of damping. Thus, it was possible to model the subsurface conditions on the basis of the following physical properties for each stratum:

1. Thickness.
2. Shear wave velocity.
3. Density.
4. Damping.

A complete description of the procedure is presented in the Duke, Leeds, Matthieson, and Frazer paper (Reference 15).

Amplification spectra for the Surry site and the Taft and El Centro strong motion stations were compared using 10% of critical damping in the overlying soil strata. This damping value is considered conservative under the fairly large earthquake motion assumed for the design-basis earthquake.

This comparison indicates that the amplification spectrum at the Surry site is approximately the same as that at the Taft, California, strong motion site, and appears to be lower than that at the El Centro, California, strong motion site.

The maximum expected amplification at the Surry site is about 2, and occurs at longer periods, about 0.75 seconds or more.

Amplification at long periods has been observed in other areas of deep soil strata (Mexico City, San Francisco, etc.). Available records on rocks and earthquake motion indicate that maximum acceleration and dominant frequencies occur at relatively short periods when the amplification ratio for the site is less than 2, and that at periods on the order of 0.75 seconds and longer, accelerations are much smaller. Since the motion at the ground surface is the product of the rock motion times the amplification ratio, it is apparent that, for an amplification spectrum as described here, the maximum acceleration at or near ground surface will be less than twice the maximum accelerations at the rock surface. Orbital particle velocities and displacements at the ground surface would be larger than at the rock surface, since these are larger for the longer periods.

In discussions with consultants of the Atomic Energy Commission, it was agreed that a maximum rock acceleration of 0.07g was appropriate at this site. If it were assumed that the amplification ratio was 2.0 even in the short period portions of the spectrum, a very conservative assumption, the maximum acceleration at the ground surface would be about 0.14g. It is pertinent to compare these theoretical studies with observations. Some recent observations have indicated amplification or soil ground motion over that of bedrock motion on the order of 3 to 4, and increased amplification as the soil thickness increases. These possibilities have been investigated by the use of the amplification spectrum. Figure 2.5-3 presents the results of varying layer thickness. Under small earthquake motions, the soil layers would act essentially as elastic media, and with small amounts of damping, amplification of 3 to 6 would be expected. As the earthquake motion increases in magnitude, damping would increase, thereby reducing the amplification of basement motion for larger earthquakes.

The computed amplification of 3 to 4 is consistent with observed amplification in small earthquakes and moderate soil thickness. Apparently, though, if the properties of the various strata remain essentially similar, the greater the thickness of overburden material, the lower the amplification as a result of damping in the soil.

This fact of decreasing amplification with increasing depth can be more easily visualized for the one-layer system as presented in Reference 16.

Thus these studies indicate:

1. On the basis of computed amplification ratios for the design-basis earthquake, a maximum horizontal ground acceleration of 0.15g is conservative.

2. The amplification spectra for the site compare closely with those at other overburden sites for which instrumental records are available. No unusual amplifications would be expected because of the deep overburden. Accordingly, it is possible to evaluate the expected ground motion at Surry by comparison with available instrumental records from other overburden sites.

2.5.5.3 **Available Strong Motion Data**

The magnitude 5 to 5.5 earthquake selected for the design-basis earthquake corresponds to a maximum epicentral intensity of about VII. The maximum intensity reported during any historical earthquake is referenced to the worst conditions at a particular location; i.e., the maximum amplitude of ground motion, adverse subsurface soil conditions, and poor construction.

These conditions may well have existed near the epicenters of the 1875 shock and the 1927 shock, and may have contributed to the maximum intensity reported. It is probable that similar earthquakes near the Surry Power Station site would result in a much lower maximum intensity for structures founded upon the firmer soils of the site. Therefore, the use of an intensity-VII shock as the design-basis earthquake is a conservative assumption. But, given the importance of the proposed facility, it has been assumed that the maximum expected ground motions, based on a historical evaluation of recorded ground motions, will occur at the Surry site.

Since the east coast of the United States has in general been seismically quiet, little data are available for the region around the site. However, a reasonable amount of instrument data is available for California earthquakes in the range of magnitudes from 5 to 5.5 at sites with subsurface conditions similar to the Surry site. Much of these data were originally presented by Gutenberg and Richter (Reference 17), and an attempt was made to develop an empirical relationship between epicentral intensity and maximum ground acceleration. The ground acceleration indicated for a maximum intensity of VII according to the Gutenberg and Richter formula is about 7% of gravity. This work was later continued by Hershberger (Reference 18). Hershberger used these additional data to refine the Gutenberg and Richter formulas. The ground acceleration indicated for a maximum intensity of VII, according to Hershberger's data, is about 13% of gravity.

Several other investigators have also compiled instrumental data regarding earthquakes in the range of magnitudes being considered in the current study William K. Cloud (Reference 19), in a paper reporting maximum accelerations during earthquakes, gives instrumental data for several shocks with magnitudes between 5 and 6. All but one of these records correspond to sites on soil. The maximum accelerations recorded during these shocks ranged between 10.2% and 17.3% of gravity, at epicentral distances of less than 13 miles. The average of these accelerations is about 14.5% of gravity.

John H. Wiggins, Jr. (Reference 20), reports maximum ground accelerations at epicentral distances of less than 20 miles for six California earthquakes with magnitudes between 5.2 and

5.6. The maximum recorded acceleration for any of these shocks was 15.9% of gravity for a magnitude 5.2 shock at a distance of 12 miles. The epicentral intensity of the shock was VII.

2.5.5.4 **Theoretical Studies**

The possible ground accelerations at the site have also been analyzed on the basis of empirical formulas developed by Dr. Kiyoshi Kanai of Japan.

Using data from Japanese earthquakes, Dr. Kanai (Reference 21) has developed formulas relating earthquake magnitude to maximum particle acceleration in basement rock. According to the Kanai formulas, acceleration in the basement rock at Surry would be about 4 to 7% of gravity, and the maximum ground acceleration at foundation level would be about 10 to 13% of gravity.

2.5.5.5 **Summary**

The preceding studies have evaluated the probable maximum acceleration for the design-basis earthquake at or near the ground surface by three different approaches. All three have indicated that a maximum horizontal ground acceleration of 0.15g at foundation levels is a conservative and reasonable value.

2.5.6 Conclusions

It is concluded that the site will not experience any significant earthquake ground motion during the estimated useful life of the nuclear facility. Historically, there is no basis for expecting more than very minor ground motion at the site. However, to provide protection against the remote contingency of an earthquake, the Class I structures and equipment are designed to withstand and remain operating at an earthquake ground motion producing accelerations as high as 7% of gravity. For a safe and orderly shutdown of the station, a maximum horizontal ground acceleration of 15% of gravity is used. This ground acceleration might result from a magnitude 5 to 5.5 earthquake in the basement rock near the site. The seismic history and the known tectonics of the region indicate that the possibility of such an occurrence is quite remote. Vertical accelerations are taken as two-thirds the appropriate maximum ground accelerations acting simultaneously and in phase to produce maximum loads or stresses.

Design is based on the use of response spectra.

Dr. N. M. Newmark has indicated that the primary influence on the response of structures with varying natural frequencies results from:

1. The maximum ground acceleration for structures having a frequency of more than 2 cycles per second.
2. The maximum ground velocity for structures with natural frequencies between 0.3 cycles and 2 cycles per second.
3. The maximum ground displacement for structures with natural frequencies less than about 0.3 cycles per second.

As previously indicated, the greatest amplification of the bedrock motion occurs for the longer periods. To allow for this, the spectra have been adjusted in the longer-period portions by normalizing these portions to somewhat higher values than the standard Housner spectra.

For frequencies higher than about 2 cycles per second, the Housner spectra have been followed, normalized to a horizontal ground acceleration of 7% of gravity for the operating-basis earthquake, and 15% of gravity for the design basis earthquake.

In the frequency range between 0.3 cycles per second and 2 cycles per second, Housner's average spectra have been normalized to a maximum ground velocity of about 4 in/sec for the operating-basis earthquake, and 9 in/sec for the design-basis earthquake.

For frequencies lower than about 0.3 cycles per second, the spectra were prepared using data suggested by Drs. Newmark and Hall in a recent paper (Reference 22).

Although a relatively high degree of conservatism is introduced into the intermediate frequency range through this approach, the basic principal of average response spectra recorded for sites on deep overburden is adhered to. The resulting spectra used in design are shown on Figures 2.5-5 and 2.5-6 for the operating-basis earthquake and the design-basis earthquake, respectively.

2.5 REFERENCES

1. Weston Geophysical Research, Inc., *Seismic Analysis, Surry Nuclear Power Plant Site, Virginia Electric and Power Company*, Weston, Massachusetts.
2. G. W. Fischer, F. J. Pettijohn, J. C. Reed, Jr., and N. K. Weaver, "Studies of Appalachian Geology Central and Southern," *Interscience*, New York, 1970.
3. S. K. Neuschel, "Correlation of Aeromagnetics and Aeroradio Activity with Lithology in the Spotsylvania Area," *Geologic Society of America Bulletin*, V. 81, 1970, pp. 3575-3582.
4. M. W. Higgins, Personal Communications, 1973.
5. Weston Geophysical Research Inc., *Seismic Analysis, Surry Nuclear Power Plant Site, Virginia Electric Power Company*, 1967.
6. Virginia Electric and Power Company, Surry Power Station "Independent Spent Fuel Storage Installation," *Safety Analysis Report*, October 1982.
7. G. A. Bollinger, "Historical and Recent Seismic Activity in South Carolina," *Bulletin of the Seismological Society of America*, Vol. 62, No. 3, 1972.
8. G. A. Bollinger, "Virginia's Two Largest Earthquakes - December 22, 1875 and May 31, 1897," *Bulletin of the Seismological Society of America*, Vol. 61, No. 4, pp. 1033-1039, 1971.

9. G. A. Bollinger, "Seismicity of the Southeastern United States," *Bulletin of the Seismological Society of America*, Vol. 63, No. 5, pp. 1785-1808, October 1973.

10. G. H. Johnson, "Geology of Yorktown, Poquoson West, and Poquoson East Quadrangles," *Virginia Division of Mineral Resources, Report of Investigations 30*, 1972.

11. K. F. Bick and N. K. Coch, "Geology of the Williamsburg, Hog Island, and Bacon's Castle Quadrangles, Virginia," *Virginia Division of Mineral Resources, Department of Invest*, No. 18, 1969.

12. Dames & Moore, *Environmental Studies-Proposed Nuclear Power Plant, Surry, Virginia*, Virginia Electric and Power Company, December 1, 1966.

13. N. H. Ambrasey and S. K. Sarma, "Response of Dams to Strong Earthquakes," *Geotechnique*, September 1967.

14. Trifunac and Brady, "The Correlation of Seismic Intensity Scales with the Peaks of Recorded Strong Ground Motion," *Bulletin of the Seismological Society of America*, Vol. 65, No. 1, pp. 139-162, February 1975.

15. R. B. Matthieson, C. M. Duke, D. J. Leeds, and J. C. Fraser, *Site Characteristics of Southern California, Strong-Motion Earthquake Stations*, UCLA Report No. 64-B, February 1964.

16. Surry PSAR, Supplement, pp. S9.13-13 to -18 and Figures S9.13A-l, -2, and -3.

17. B. Gutenberg and C. F. Richter, "Earthquake Magnitude, Intensity, Energy and Acceleration," Second Paper, *Seismological Society of America Bulletin*, Vol. 46, pp. 45-145, 1956.

18. J. Hershberger, "A Comparison of Earthquake Accelerations with Intensity Ratings," *Seismological Society of America Bulletin*, Vol. 46, pp. 317-320, 1956.

19. W. K. Cloud, *Maximum Accelerations During Earthquakes*, unpublished report.

20. J. H. Wiggins, Jr., "Construction of Strong Motion Response Spectra from Magnitude and Distance Data," *Seismological Society of America Bulletin*, Vol. 54, pp. 1257-1269, 1964.

21. K. Kanai, "Improved Empirical Formulae for the Characteristics of Strong Earthquake Motions," *Proceedings of Japan Earthquake Engineering Symposium*, 1966, pp. 1-4.

22. N. M. Newmark and W. J. Hall, *Seismic Design Criteria for Nuclear Reactor Facilities*, May 25, 1967.

Table 2.5-1
MODIFIED MERCALLI INTENSITY (DAMAGE) SCALE OF 1931
(ABRIDGED)

I. Not felt except by a very few under especially favorable circumstances. (I Rossi-Forel Scale).

II. Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing. (I to II Rossi-Forel Scale.)

III. Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motorcars may rock slightly. Vibration like passing of truck. Duration estimated. (III Rossi-Forel Scale.)

IV. During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed. Walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rocked noticeably. (IV to V Rossi-Forel Scale.)

V. Felt by nearly everyone, many awakened. Some dishes, windows, ect., broken. A few instances of cracked plaster. Unstable objects overturned. Disturbance of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop. (V to VI Rossi-Forel Scale.)

VI. Felt by all. Many frightened and run outdoors. Some heavy furniture moved. A few instances of fallen plaster or damaged chimneys. Damage slight. (VI to VIII Rossi-Forel Scale.)

VII. Everybody runs outdoors. Damage negligible in buildings of good design and construction. Slight to moderate in well-built ordinary structures. Considerably in poorly-built or badly-designed structures. Some chimneys broken. Noticed by persons driving motorcars. (VIII Rossi-Forel Scale.)

VIII. Damage slight in specially-designed structures. Considerable in ordinary substantial buildings with partial collapse. Great in poorly-built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Persons driving motorcars disturbed. (VIII+ to IX Rossi-Forel Scale.)

IX. Damage considerable in specially-designed structures. Well-designed frame structures thrown out of plumb. Great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken. (IX+ Rossi-Forel Scale.)

X. Some well-built wooden structures destroyed. Most masonry and frame structures destroyed with foundations. Ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks. (X Rossi-Forel Scale.)

XI. Few, if any, (masonry) structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipelines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.

XII. Damage total. Waves seen on ground surface. Lines of sight and level distorted. Objects thrown into the air.

Table 2.5-2
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1774	Feb. 21	14:	VI	Va.	37.3	77.4	58,000	43.5
1774	Feb. 22	05:	V-VI	Va.	37.5	77.5	-	50.8
1802	Aug. 23	05:	V	Richmond, Va.	37.6	77.4	-	49.3
1807	Apr. 30	04:00	V	Richmond-Fredricksburg Area	-	-	-	-
1811[a]	Dec. 16	02:00	XII	New Madrid, Mo.	36.6	89.6	2,000,000	705
1812[a]	Jan. 23	-	XII	New Madrid, Mo.	36.6	89.6	-	705
1812[a]	Feb. 7	-	XII	New Madrid, Mo.	36.6	89.6	-	705
1812	Apr. 22	04:00	IV	Richmond, Va.	37.6	77.4	-	-
1816	Dec. 31	13:00	III	Norfolk, Va.	36.8	76.3	-	33.5
1824	July 15	11:20	V	W. Va.-Ohio	-	-	63,000	-
1826	Aug. 9	21:00	I-III	Richmond, Va.	37.6	77.4	-	-
1826	Aug. 10	12:00	II-III	Richmond, Va.	37.6	77.4	-	49.3
1828	Mar. 9	22:00	V	W.-Central Va.	-	-	218,000	49.3
1833	Aug. 27	06:00	V	Charlottesville-Richmond, Va. 1852	37.75	78.	61,000	84.3

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-2 (CONTINUED)
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1852[a]	Apr. 29	13:00	VI	Va.-N.C.-Tenn. (Mt. Rogers in Va.)	36.6	81.6	187,000	270
1852	Nov. 2	18:35	VI	Eastern Va.	37.75	78.	32,000	84.3
1853	May 2	09:20	V-VI	Va.-W Va.-Ohio	38.5	79.5	72,000	179
1861	Aug. 31	05:22	VI	SW Va.-W N.C.	-	-	300,000	-
1870[a]	Oct. 20	11:25	IX	Canada (Baie St. Paul)	47.4	70.5	1,000,000	780
1871	Oct. 9	-	VII	Wilmington, Del.	39.75	75.5	-	195
1872	June 4	22:00	III	Chesterfield	37.60	77.4	9000	46.4
1875	Dec. 22	-	VI	Arvonia, Va.	37.5	77.5	50,000	50.8
1883	Mar. 11	18:57	IV-V	Harford County, Md.	39.5	76.5	-	164.5
1883	Mar. 12	00:	V	Harford County, Md.	39.5	76.4	-	163.7
1885	Jan. 2	21:16	V	Loudon Co. Va Md.-Va. Border	39.2	77.5	9000	149.5
1885	Aug. 9	23:35	V	Va.	37.7	78.8	29,000	121.5
1886[a]	Aug. 31	21:51	X	Charleston, S.C.	32.9	80.0	2,000,000	352
1889	Mar. 8	18:40	VI	SE Pa.	40.0	76.75	4000	197
1897[a]	May 3	12:18	VI	Pulaski, Va.	37.1	80.7	150,000	222.5

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-2 (CONTINUED)
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1897[a]	May 31	13:58	VIII	Giles County, Va.	37.3	80.7	280,000	222
1897	June 28	-	V	Roanoke, Va.	37.3	79.9	9500	176.5
1897	Dec. 18	18:45	V	Ashland, Va.	37.7	77.5	10,000	57.2
1906	May 8	12:41	V	Del.	38.7	75.7	400	118.2
1907	Feb. 11	08:22	VI	Arvonia, Va.	37.7	78.3	2000	94.6
1908	Aug. 23	04:30	V	Powhatan, Va.	37.5	77.9	450	71.0
1909	Apr. 2	02:25	V-VI	W. Va.-Md.-Pa.	39.4	78.0	2500	174.5
1910	May 8	16:10	V	Arvonia, Va.	37.7	78.4	350	99.5
1918	Apr. 9	21:09	V-VI	Luray, Va.	38.7	78.4	100,00	139.0
1918	Apr. 19	11:55	III	Norfolk, Va.	36.9	76.3	-	33.2
1919	Sept. 5	21:46	VI	Front Royal, Va.	38.8	78.2	-	141.0
1921	Aug. 7	01:30	VI	New Canton, Va.	37.8	78.4	2800	100.5
1923	Dec. 31	-	V	Clarke County, Va. Boyse Section	39.2	78.	-	156.5
1924	Jan. 1	-	IV-V	Clarke County, Va.	39.2	78.	-	156.5
1924	Dec. 25	-	V	Roanoke, Va.	37.3	75.9	-	177.0

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-2 (CONTINUED)
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1925	July 14	16:20	IV	Richmond, Va.	37.6	77.4	-	49.3
1927	June 10	02:16	V	Augusta County, Va.	38.	79.	2500	140.0
1928	Oct. 30	06:45	IV	Richmond, Va.	37.5	77.5	3100	50.8
1929	Dec. 25	21:56	VI	Albemarle County, Va.	38.1	78.5	1000	120.0
1932	Jan. 4	23:05	V	Buckingham County, Va.	37.6	78.6	800	110.3
1935[a]	Nov. 1	03:30	V	Elkins, W.Va.	38.9	75.9	-	212.0
1939	Nov. 14	21:54	V	Salem County, N.J.	39.6	75.2	6000	187.2
1940	Mar. 25	-	V	Shenandoah Valley, Va.	38.9	78.6	400	157.5
1948	Jan. 4	-	VI	Buckingham, Va.	37.5	78.5	1700	108.3
1949	May 8	06:01	IV-V	Powhatan-Richmond, Va.	37.6	77.9	2700	72.5
1950	Nov. 26	02:45	V	Buckingham County, Va.	37.7	78.4	900	99.5
1951	Mar. 9	02:00	-	Richmond, Va.	37.6	77.4	-	49.3
1959[a]	Apr. 23	20:58:41	VI	Giles County, Va.	37.5	80.5	3000	210.0
Beyond 200-mile distance but significant to study.								
1966	May 31	06:14:02	V	Powhatan, Va.	37.6	78.0	28,000	78.8

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-2 (CONTINUED)
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND
ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1968[a]	Dec. 10	04:12	V	SE N. J.	39.7	74.6	-	208.0
1969	Dec. 11	18:44	V	Richmond, Va.	37.8	77.4	6500	61.0
1969	Dec. 11	23:44	V	Richmond, Va.	37.8	77.4	3500	61.0
1973	Mar. 1	03:30	V-VI	Delaware County, Pa.	39.8	75.3	-	200
1974	Mar. 23	09:49	-	Shenandoah Valley, Va.	38.92	77.78	-	135.06
1974	Apr. 28	09:19	IV	Wilmington, Del.	39.75	75.5	-	195.0
1974	Nov. 7	16:31	IV	Charlottesville, Va.	37.75	78.20	-	92.45
1977	Feb. 10	19:14	V (VI)	Wilmington, Del.	39.75	75.5	-	195.0
1977	Feb. 27	20:05	V	Charlottesville, Va.	37.90	78.63	-	118.11
1977	Sept. 30	20:53	-	Louisburg, N.C.	36.05	78.35	-	120.46
1978	Feb. 25	03:53	IV	Reidsville, N.C.	36.19	79.30	-	159.98
1978	Apr. 26	19:30	-	Martinsburg, W. Va.	39.63	78.20	-	189.00
1978	Jul. 16	06:40	V	Lancaster, Pa.	39.93	76.34	-	191.85
1978	Oct. 6	19:25	V	York, Pa.	39.97	76.51	-	193.93
1978	Oct. 29	12:22	-	Louisa County, Va.	38.03	78.10	-	97.86

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-2 (CONTINUED)
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1978	Nov. 15	08:33	-	Richmond, Va.	37.65	77.55	-	58.13
1979	Nov. 6	04:05	-	Cumberland County, Va.	37.44	78.26	-	88.72
1979	Nov. 11	07:22	-	Richmond, Va.	37.72	77.47	-	43.48
1980	Apr. 26	03:60	-	Hanover County, Va.	37.77	77.58	-	64.47
1980	May 18	03:31	-	Powhatan County, Va.	37.58	77.94	-	74.70
1980	May 18	22:34	-	Louisa County, Va.	37.97	78.07	-	94.08
1980	Aug. 4	10:13	-	Louisa County, Va.	38.07	77.76	-	85.85
1980	Sept. 21	10:03	-	Marlinton, W. Va.	38.18	80.07	-	198.04
1980	Sept. 26	01:32	-	Louisa County, Va.	38.07	77.76	-	86.22
1980	Sept. 26	05:04	-	Warrenton, Va.	38.78	77.72	-	124.97
1980	Oct. 11	22:40	-	Louisa County, Va.	38.12	77.81	-	90.22
1980	Oct. 14	01:20	-	Floyd County, Va.	37.08	80.23	-	195.53
1980	Nov. 5	21:48	Felt	Marlinton, W. Va.	38.18	79.90	-	189.37
1980	Nov. 25	07:44	-	Marlinton, W. Va.	38.10	80.12	-	198.83
1981	Jan. 19	21:54	-	Buckingham County, Va.	37.73	78.44	-	103.95

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-2 (CONTINUED)
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1981	Jan. 21	16:30	-	Buckingham County, Va.	37.77	78.42	-	103.99
1981	Feb. 11	13:44	IV	Buckingham County, Va.	37.72	78.44	-	103.70
1981	Feb. 11	13:51	III	Buckingham County, Va.	37.75	78.41	-	102.95
1981	Feb. 11	13:52	Felt	Buckingham County, Va.	37.72	78.45	-	104.21
1981	Mar. 20	04:02	-	Richmond, Va.	37.52	77.68	-	59.96
1981	Apr. 9	07:13	-	Powhatan County, Va.	37.48	77.82	-	66.12
1981	Apr. 9	07:35	-	Powhatan County, Va.	37.47	77.87	-	68.51
1981	Apr. 16	13:49	-	Cumberland County, Va.	37.61	78.22	-	89.78
1981	June 6	08:06	-	Bath County, Va.	38.21	79.51	-	170.57
1981	July 30	12:00	-	Louisa County, Va.	38.19	78.09	-	104.50
1981	Oct. 3	09:56	-	Burlington, N.C.	36.01	79.35	-	168.20
1981	Nov. 23	13:15	-	Augusta County, Va.	38.24	79.05	-	149.15
1984	Apr. 23	01:36	-	Lancaster County, Pa.	39.95	76.32	-	192.5
1984	Aug. 17	18:05	-	Fluvanna County, Va.	37.87	78.32	-	101.3
1986	Feb. 2	21:50	-	Hanover County, Va.	37.60	77.39	-	48.2

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-2 (CONTINUED)
SIGNIFICANT EARTHQUAKES OF ALL EARTHQUAKES WITHIN 50 MILES OF SITE AND ALL EARTHQUAKES OF INTENSITY V OR GREATER WITHIN 200 MILES OF SITE[b]

Year	Date	Time	Epicentral Intensity	Approximate Location	N Lat	W Long	Perceptible Area (Sq Mi)	Distance from Site
1986	Dec. 10	11:30	-	Richmond, Va.	37.59	77.47	-	51.0
1990	Jan. 13	20:47	-	Baltimore County, Md.	39.37	76.85	-	151.7
1991	Mar. 15	06:54	-	Goochland County, Va.	37.75	77.91	-	77.4
1993	Mar. 15	04:29	-	Howard County, Md.	39.20	76.87	-	140.1
1994	Aug. 6	19:54	-	Pamlico County, N.C.	35.10	76.79	-	142.7
1995	Aug. 3	13:07	-	James City County, Va.	37.40	76.69	-	15.9

a. Beyond 200-mile distance but significant to study.
b. 1774 through 1995.

Table 2.5-3
EARTHQUAKE CYCLES OF SIGNIFICANT MOTION

Earthquake Record	Number of Cycles of Significant Motion[a]
Taft 1952 S69E	9
Taft 1952 N21E	9
El Centro 1940 NS	10
El Centro 1940 NS	2
Golden Gate 1957 NE	3
Golden Gate 1957 S80E	5
Olympia 1949 S86W	7
Helena 1935 NS	5
Helena 1935 EW	5
Eureka N79 E	4
Eureka N11W	7
Parkfield Site 2	2
Parkfield Site 5 N5W	1
Parkfield Site 5 N85E	1
Hollister	3

a. Number of cycles in which acceleration equals or exceeds one-half the peak acceleration for direction recorded.

Figure 2.5-1
REGIONAL TECTONICS

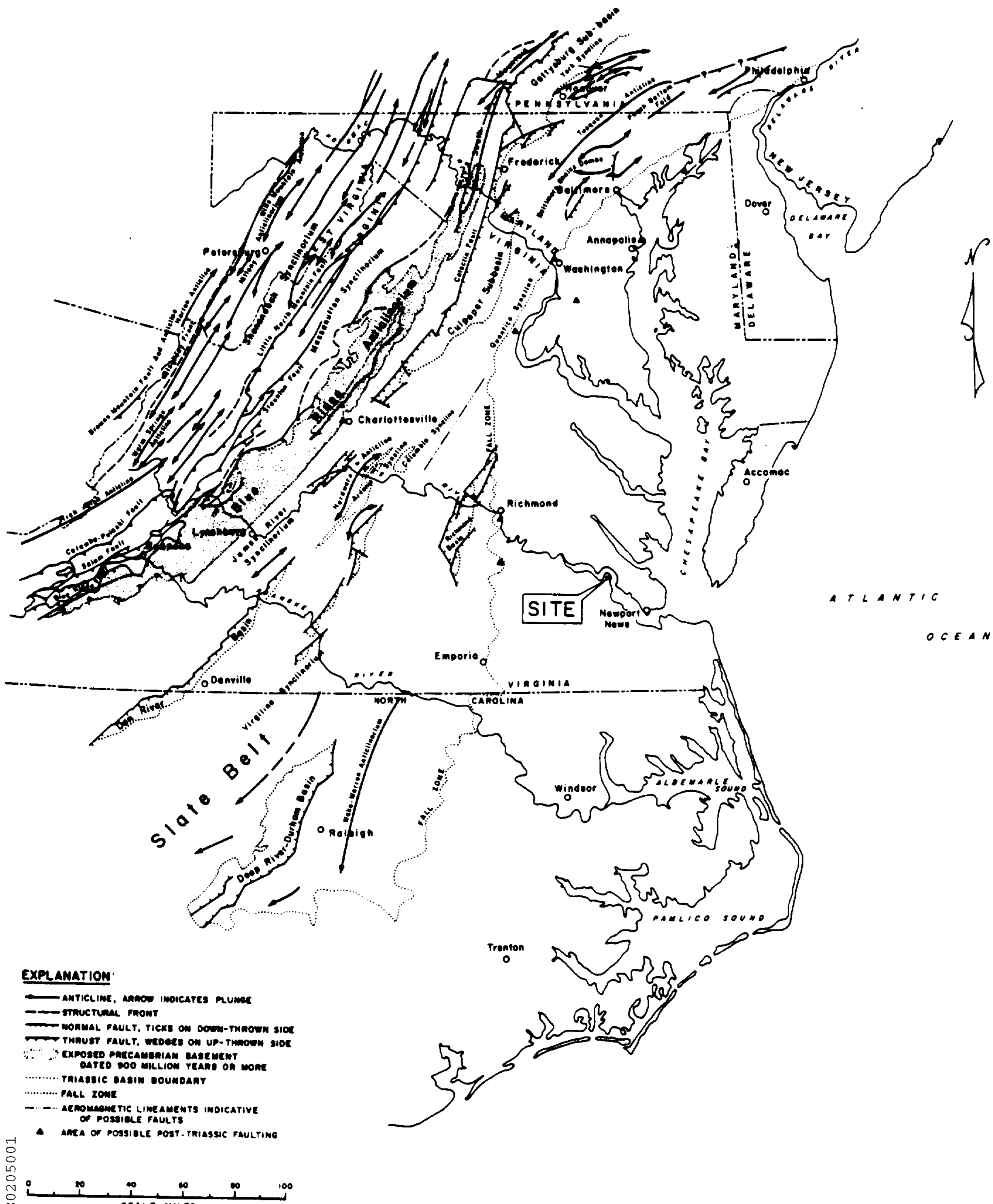


Figure 2.5-2
REGIONAL EPICENTER MAP

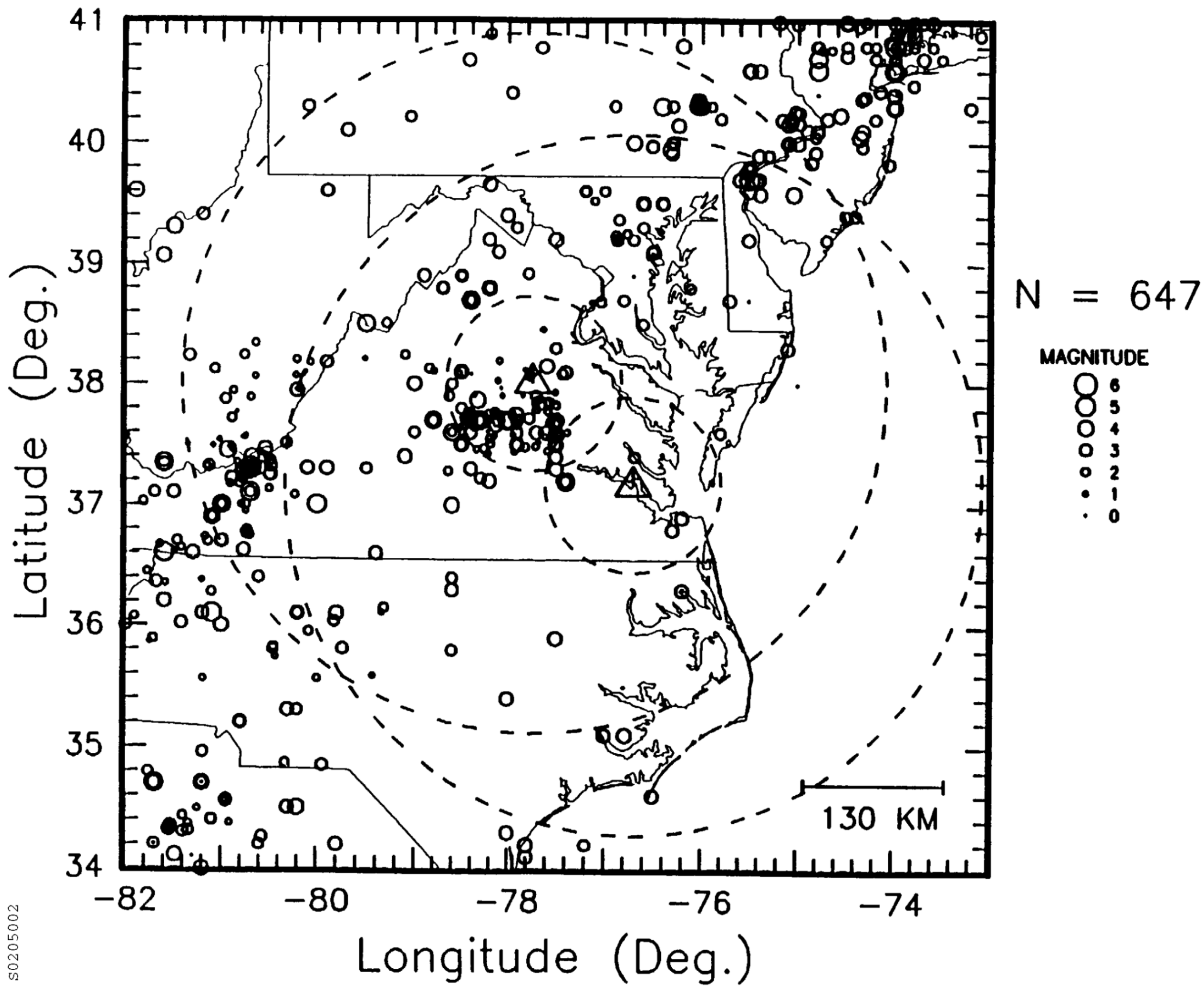


Figure 2.5-3
AMPLIFICATION SPECTRA FOR THREE TYPICAL EARTHQUAKES 10% DAMPING

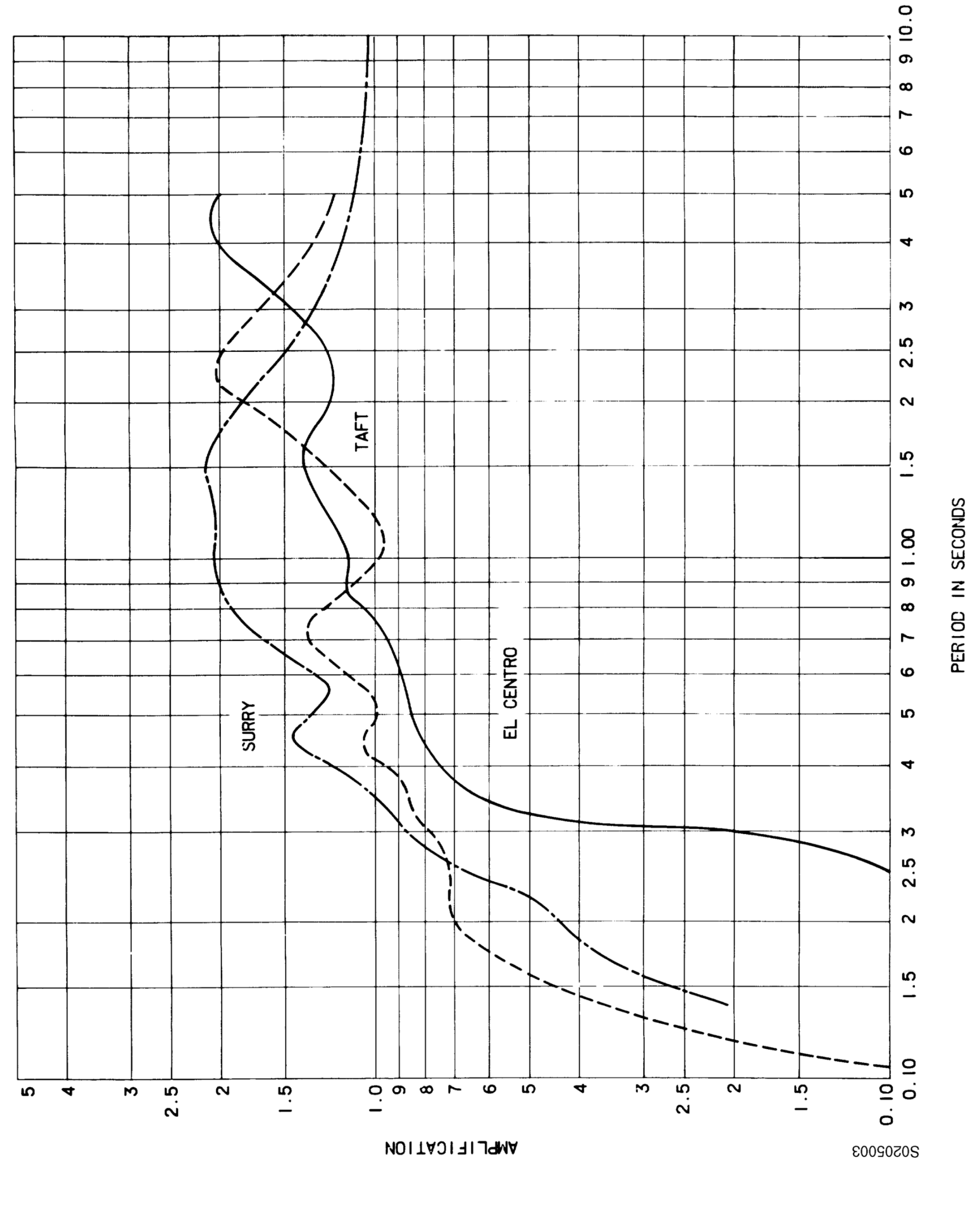


Figure 2.5-4
AMPLIFICATION SPECTRA FOR FOUR OVERBURDEN DEPTHS 10% DAMPING

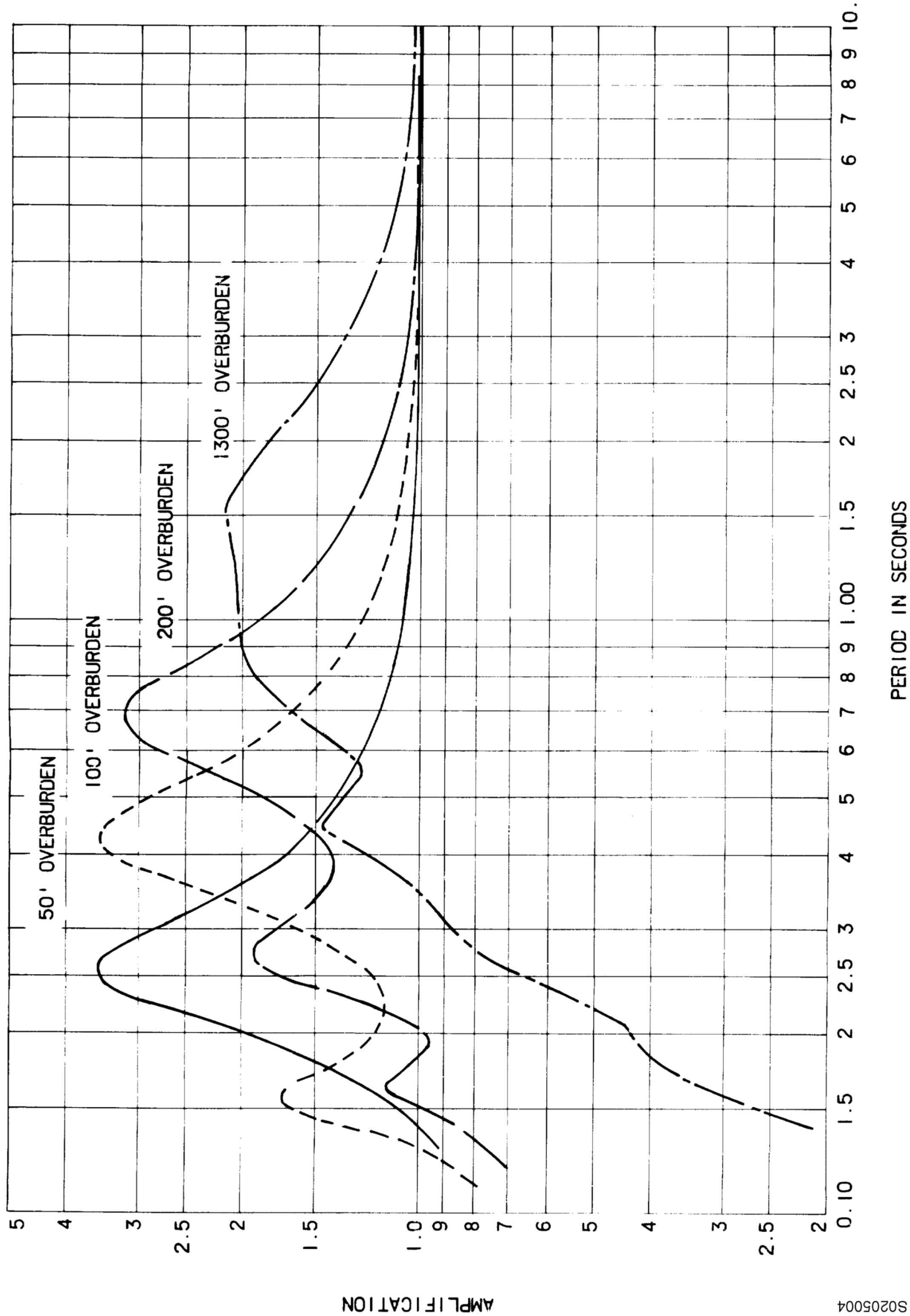


Figure 2.5-5
RESPONSE SPECTRA OPERATIONAL-BASIS EARTHQUAKE

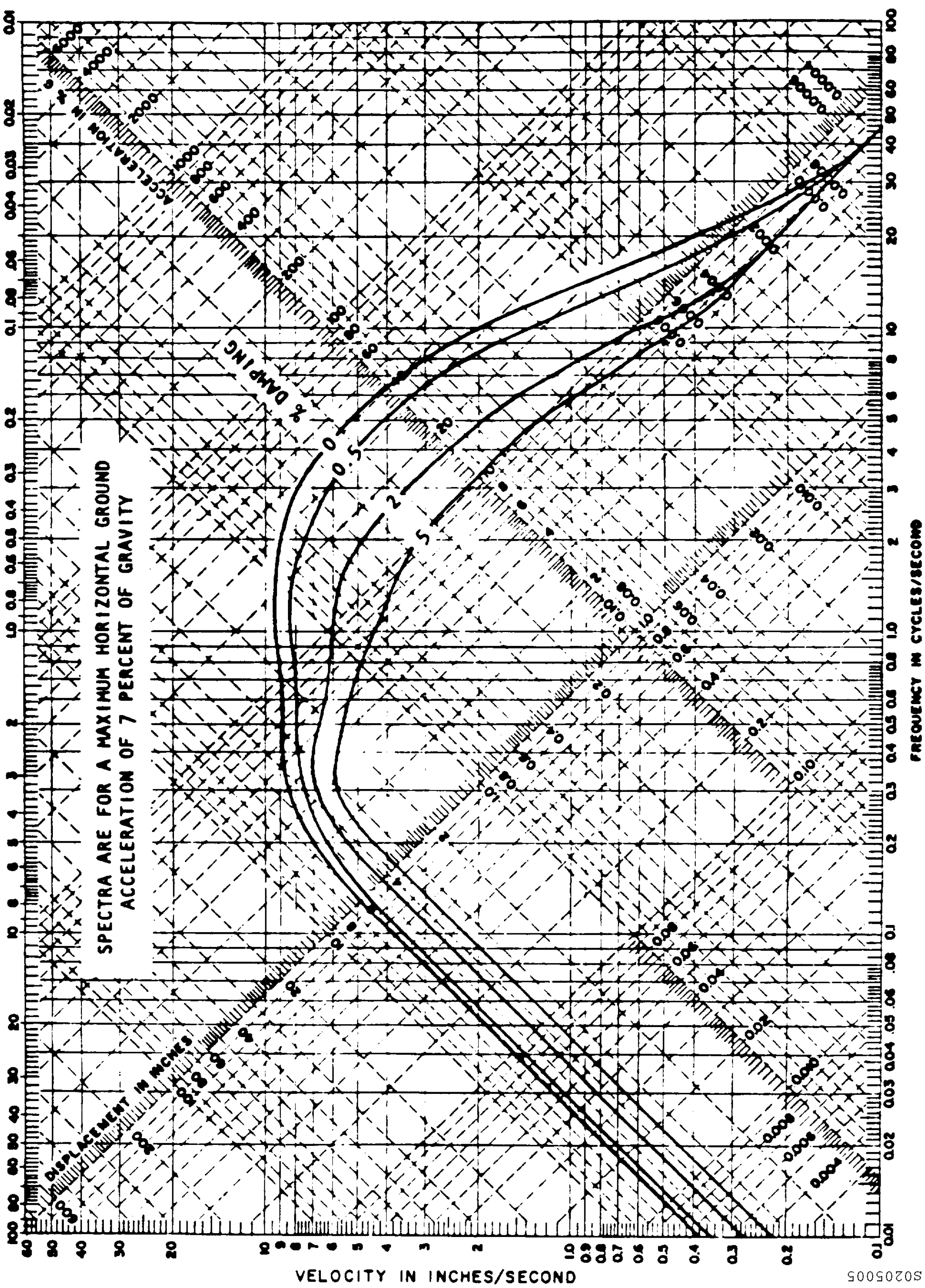
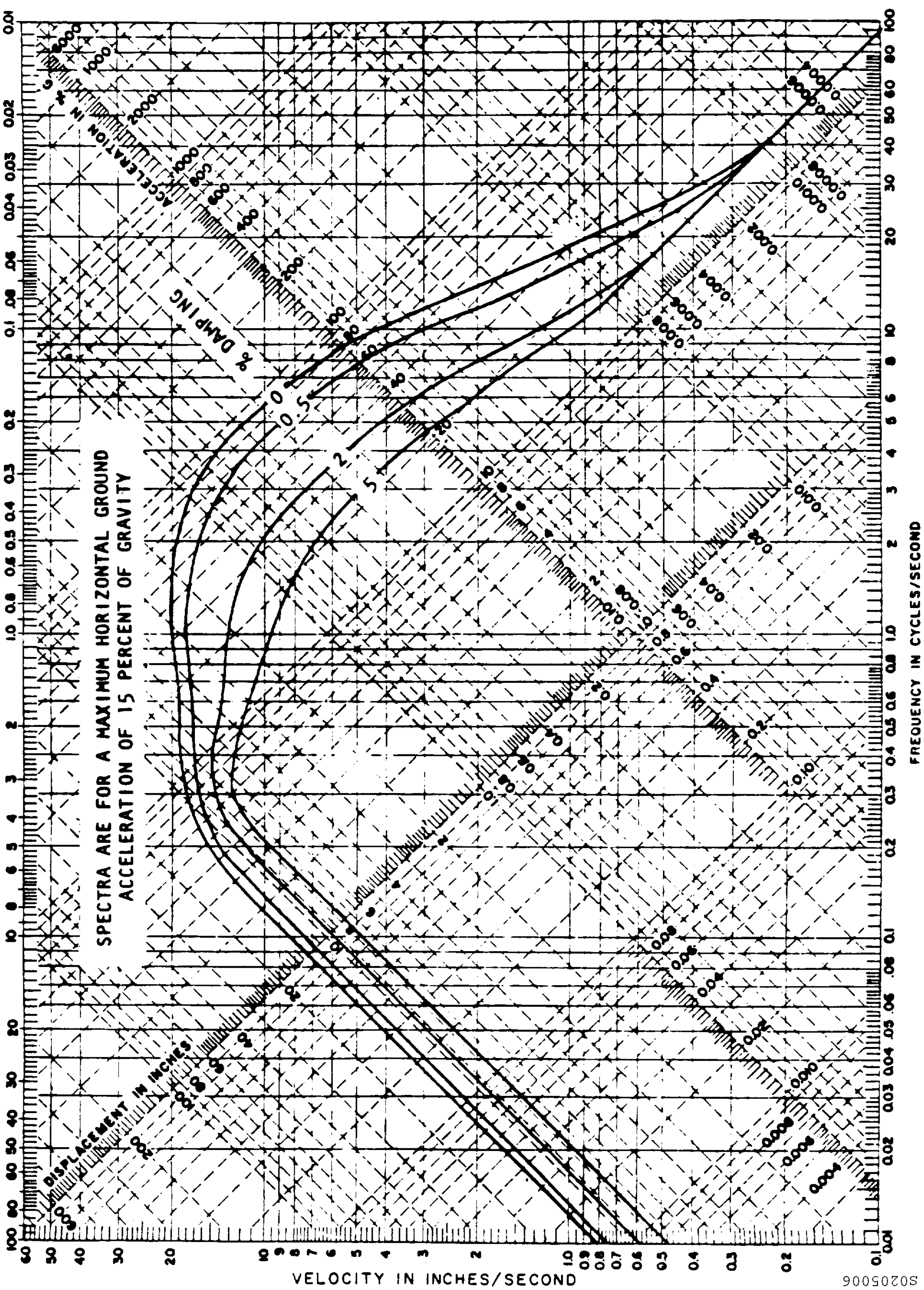


Figure 2.5-6
RESPONSE SPECTRA DESIGN-BASIS EARTHQUAKE



Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 3

Intentionally Blank

Chapter 3: Reactor
Table of Contents

Chapter 3: Reactor
Table of Contents (continued)

Chapter 3: Reactor
Table of Contents (continued)

Chapter 3: Reactor

List of Tables

Chapter 3: Reactor

List of Figures

Chapter 3: Reactor

List of Figures (continued)

CHAPTER 3 REACTOR

3.1 GENERAL

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

The reactor core is a multi-region cycled core. The fuel rods are coldworked, partially annealed zirconium alloy tubes containing slightly enriched uranium dioxide fuel. All fuel rods are pressurized with helium during fabrication to reduce stresses and strains and to increase fatigue life. Beginning in Cycle 21, some fuel rods contain fuel with a thin layer of boride coating on the outer surface to act as integral fuel burnable absorber (IFBA, References 1 & 2).

The fuel assembly is a canless type with the basic assembly consisting of the control rod guide thimbles joined to the grids and the top and bottom nozzles. The fuel rods are supported at several points along their length by the grids.

Control rod assemblies, flux suppression inserts (Unit 1 only, Cycles 13 through 20), and burnable poison rods are inserted into the guide thimbles of the fuel assemblies. Flux suppression inserts were removed after Cycle 20 of Unit 1. Beginning in Cycle 21, cores may use IFBA and/or discrete (fixed) burnable absorber rods. The absorber sections of the control rods are fabricated of silver-indium-cadmium alloy sealed in stainless steel tubes. The absorber material in the fixed burnable poison rods is in the form of either borosilicate glass sealed in stainless steel tubes, or Al_2O_3 - B_4C pellets in Zircaloy-4 tubes. The flux suppression inserts in Unit 1 consist of hafnium bar encapsulated in Zircaloy-4 tubing.

The control rod drive mechanisms are of the magnetic latch type. The latches are controlled by three magnetic coils. They are so designed that upon a loss of power to the coils, the control rod assembly is released and falls by gravity to shut down the reactor.

3.1 REFERENCES

1. S. L. Davidson et al., *Reference Core Report, VANTAGE 5 Fuel Assembly,* WCAP-10444-P-A, September 1985.
2. S. L. Davidson et al., *VANTAGE+ Fuel Assembly Reference Core Report,* WCAP-12610-P-A, April 1995.

Intentionally Blank

3.2 DESIGN BASES

3.2.1 Performance Objectives

The reactor core average thermal power is 2587 MWt. The nuclear steam supply system power rating is 2599 MWt, which includes 12 MWt pump heat. This is the maximum thermal power rating for which the plant heat removal systems are designed.

The reactor core fuel loading and incore fuel management are designed to yield prespecified cycle average and core average burn-up values. Data for successive reload cycles can be found in the respective reload safety evaluations prepared by Vepco. Typical nuclear design data (representative of the initial core) can be found in Table 3.3-1.

The fuel rod cladding is designed to maintain its integrity for the anticipated rod life. The effects of fission gas release, fuel dimensional changes, and corrosion-induced and irradiation-induced changes in the mechanical properties of cladding are considered in the design of the fuel assemblies.

The control rods, being long and slender, are relatively free to conform to any small misalignments. Tests have shown that the rods are very easily inserted and not subject to binding even under conditions of severe misalignment.

The control rods provide sufficient reactivity control to terminate any credible power transient before reaching the departure from nucleate boiling ratio (DNBR) design limit (Section 3.2.3). This is accomplished by ensuring sufficient control rod worth to shut the reactor down by at least 1.77% in the hot condition with the most reactive control rod stuck in the fully withdrawn position. Redundant equipment is provided to add soluble poison to the reactor coolant to maintain shutdown margin when the reactor coolant is cooled to ambient temperatures.

During initial core design, experimental measurements from critical experiments or operating reactors, or both, were used to validate the methods employed in the design. Nuclear parameters were calculated for every critical phase of operation and, where applicable, were compared with design limits to show that an adequate margin of safety exists. This same general design procedure has been employed for all the subsequent reload cycles.

In the thermal/hydraulic design of reload cores, the maximum fuel and clad temperatures during normal reactor operation and at thermal overpower conditions are conservatively evaluated and verified to be consistent with safe operating limitations.

3.2.2 Design Criteria

3.2.2.1 Reactor Core Design

The reactor core, together with reliable process and decay heat removal systems and control and protection instrumentation, is designed to function throughout its design life without exceeding the following limits, which preclude fuel damage with appropriate margins for transients:

1. Minimum DNBR not less than the applicable DNBR safety analysis limit (Section 3.2.3).
2. Fuel Rod Design criteria limits defined in Section 3.5.2.6.1.

Additional information on nuclear design can be found in Section 3.3.

3.2.2.2 **Suppression of Power Oscillations**

The design of the reactor core and related protection systems ensures that power oscillations that could cause fuel damage in excess of acceptable limits are not possible. Any tendency toward oscillation is readily suppressed.

The potential for possible spatial oscillations of power distribution for this core was reviewed as part of the core stability evaluation effort described in Section 1.6.1. Ex-core instrumentation is provided to obtain necessary information concerning axial and azimuthal power distributions. This instrumentation is adequate to enable the operator to monitor and control xenon-induced oscillations. Based on the deviations detected by the long ion chambers, provisions in the reactor control and reactor protection systems reduce trip setpoints and, if necessary, initiate load cutback to maintain DNBR margin as a result of these potential oscillations in power distribution. Incore instrumentation is used to periodically calibrate and verify the information provided by the ex-core instrumentation.

3.2.2.3 **Redundancy of Reactivity Control**

Control rods and soluble boron in the reactor coolant are the two independent reactivity control systems that are provided to ensure compliance with General Design Criterion 27, as discussed in Section 1.4.

3.2.2.4 **Reactivity Hot Shutdown Capability**

The control rods and soluble boron in the reactor coolant are designed so that the core can be made and held subcritical from any hot standby or operating condition, thus complying with General Design Criterion 28 as discussed in Section 1.4.

3.2.2.5 **Reactivity Shutdown Capability**

The worth of the control rods is designed to ensure a 1.77% delta k/k shutdown margin under any operating condition with the most reactive rod stuck in the fully withdrawn position. The control rods and dissolved boron from the safety injection system also ensures no DNB occurs for the most severe cooldown transient caused by a single active failure, as discussed in Section 1.4.

3.2.2.6 **Reactivity Holddown Capability**

The reactor is normally shut down within 2 seconds of a reactor trip signal with the control rods. Sufficient soluble boron is continually available for injection to maintain the core subcritical during approach to, and at, cold shutdown.

3.2.2.7 **Reactivity Control Systems Malfunction**

The reactor protection system is capable of protecting against any single malfunction of the reactivity control system, as discussed in response to General Design Criterion 31 in Section 1.4. Reactor shutdown with control rod assemblies is completely independent of normal control functions, as discussed in Chapter 7. The protection system limits reactivity transients so that the DNBR is not less than the applicable DNBR safety analysis limit (Section 3.2.3) for any single malfunction in either the reactor coolant system or in the de-boration control system.

3.2.2.8 **Maximum Reactivity Worth of Control Rods**

Limits that include considerable margin are placed on the rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot rupture the reactor coolant boundary or disrupt the core, its support structures, or other vessel internals so as to lose the capability to cool the core.

3.2.3 Safety Limits

The reactor is capable of meeting the performance objectives described in Section 3.2.1 throughout the core life under both steady-state and transient conditions without compromising the integrity of the fuel elements. Thus, the release of unacceptable amounts of fission products to the coolant is prevented.

Design parameters pertaining to safety limits are given below for the nuclear, thermal/hydraulic, and mechanical aspects of the design. This information can be considered as the basis for the identification of Technical Specification limits and setpoints. These limits and setpoints are subject to change after each reload, or if the operating strategy during a given cycle is altered for some reason.

3.2.3.1 **Nuclear Limits**

As required by Technical Specifications, the nuclear heat flux hot channel factors, $F_q(Z)$, do not exceed the limits assumed in the safety analysis.

The nuclear axial peaking factor, F_Z^N, and the nuclear enthalpy rise hot channel factor, $F_{\Delta H}^N$, are limited in their combined relationship so as not to exceed the F_q^N or DNBR limits.

The limiting nuclear hot-channel factors are higher than those calculated at full power for the range from all control rod assemblies fully withdrawn to maximum allowable control rod assembly insertion. Control rod assembly insertion limits as a function of power are delineated in the Technical Specifications to ensure that somewhat worse hot-channel factors do not occur at lower power levels due to control rod insertion, and that the DNBR is always greater at partial power than at full power.

The reactor protection system ensures that the reactor core nuclear limits are not exceeded.

3.2.3.2 **Reactivity Control Limits**

The control system and operating procedures provide adequate control of core reactivity and power distribution. The following control limits are met:

1. Sufficient control is available to produce a minimum hot shutdown margin of 1.77% delta k/k.
2. The shutdown margin is maintained with the most reactive control rod assembly stuck in the fully withdrawn position.
3. The shutdown margin is maintained at ambient temperature by the use of soluble poison.
4. There will be no DNB following a trip as a result of any single active failure in the steam system (e.g., safety valve, relief valve, or bypass valve sticking open), even if the most reactive control rod remains fully withdrawn.

3.2.3.3 **Thermal/Hydraulic Limits**

The reactor core is designed to meet the following limiting thermal/ hydraulic criteria:

1. The minimum DNBR during normal operation, including anticipated transients, will not be less than the applicable DNBR safety analysis limits. The DNBR limits are listed in Table 3.2-1.
2. No fuel melting during Condition I and II operation.

To maintain fuel rod integrity and prevent fission product release, it is necessary to prevent clad overheating under all anticipated operating conditions. This is accomplished by preventing departure from nucleate boiling (DNB), which, if it were to occur, would cause a large decrease in the heat transfer coefficient between the fuel rods and the reactor coolant, resulting in high clad temperatures.

The ratio of the heat flux causing DNB at a particular core location, as predicted by the applicable correlation, to the existing heat flux at the same core location is the DNBR. DNB is not, however, an observable parameter during reactor operation. Therefore, the observable parameters, reactor power, reactor coolant temperature and pressure have been related to DNB through the applicable DNBR correlation. Reactor Core Safety Limit curves provided in the Core Operating Limits Report (COLR) show the loci of points of thermal power, reactor coolant system average temperature, and reactor coolant system pressure for which the minimum DNBR is not less than the safety analysis limit, that fuel centerline temperature remains below melting, that the average enthalpy at the exit of the vessel is less than or equal to the enthalpy of saturated liquid, or that the core exit quality is within limits defined by the DNBR correlation.

The core thermal and hydraulic design basis requires that departure from nucleate boiling (DNB) be avoided with a 95% probability at a 95% confidence level during normal operation and operational transients. This is one of the key analysis criteria in many of the Chapter 14 safety analyses. Historically, demonstration of compliance with this design basis has been accomplished by (1) deterministic application of key DNBR analysis uncertainties in transient analysis and (2) comparing the resultant departure from nucleate boiling ratio (DNBR) to the applicable DNBR correlation limit. The correlation DNBR limit is established to ensure that there is a 95% probability with 95% confidence that DNB will not occur when the calculated DNBR is at the DNBR limit. For normal operation, operational transients, and during transients which experience minor variations in power, temperature, and pressure near hot-full-power (HFP) conditions, a statistical application of key DNBR analysis uncertainties to the correlation DNBR limit may be employed as described below and in Section 3.4.3.2.

The Statistical DNBR Evaluation Methodology (Reference 1) is employed to determine a revised DNBR limit. This new limit combines the correlation uncertainty with the uncertainties of key DNBR analysis input parameters. Transient analysis with the revised methodology does not require that the uncertainties be applied in the initial conditions. Instead, nominal values may be used.

The Statistical DNBR Limit is developed by means of a Monte Carlo process. The variation of actual operating conditions about nominal statepoints due to parameter measurement and other key DNB uncertainties is modeled with a random number generator-based algorithm. This algorithm produces thousands of statepoints at each nominal statepoint. The random statepoints are then supplied to the core thermal-hydraulic code, COBRA or VIPRE-D, which calculates the minimum DNBR. Each DNBR is randomized by a correlation factor as described in the topical report (Reference 1). The standard deviation of the resultant DNBR distribution is increased by a small sample correction factor to obtain its 95% upper confidence limit, thereafter being combined Root-Sum-Square with code and model uncertainties to obtain the total DNBR standard deviation, σ_{total}. The Statistical DNBR Limit (SDL) is then:

$$SDL = 1 + 1.645 \text{ x } \sigma_{total}$$

in which the 1.645 multiplier is the z-value for one-sided 95% probability of a normal distribution. Thus, this SDL is consistent with the design basis that departure from nucleate boiling (DNB) will not occur on at least 95% of the limiting fuel rods during normal operation and operational transients, and any transient conditions arising from faults of moderate frequency (Conditions I and II events) at a 95% confidence level. As an additional criterion, the SDL ensures that at least 99.9% of the core avoids DNB for these conditions.

The Statistical DNBR Evaluation Methodology is employed on a transient specific basis (References 4 & 6) as indicated in Table 3.2-2 and in the transient analysis summaries in Chapter 14.

In the evaluation of DNB thermal-hydraulic performance, the design limit is conservatively increased to a safety analysis limit to provide DNB margin to offset the effect of rod bow (see Section 3.4.3.5), and any other DNB penalties that may occur and to provide flexibility in design and operation of the plant. For non-statistical (deterministic) DNB analyses, the deterministic design limit (DDL) is set equal to the applicable code/correlation limit. For statistical DNB analyses, the design DNBR limit is set equal to the applicable statistical design limit (SDL). The DNBR limits are presented in Table 3.2-1. The difference between the safety analysis limit and the design limit is the available retained DNBR margin, against which penalties may be assessed to account for the DNB effect of changes in the fuel product, plant operating conditions, or analysis methodology (e.g., fuel rod bowing).

The DNB analysis of the Westinghouse 15 x 15 SIF is based on the Statistical DNBR Evaluation Methodology (Reference 1), the COBRA-IIIC/MIT code (Reference 2), and the WRB-l DNB correlation (Reference 3) as submitted to the NRC in Reference 4, and approved by the NRC in Reference 5. The W-3 DNB correlation and a deterministic treatment of key DNBR analysis uncertainties are used when any of the conditions are outside the range of the WRB-l DNB correlation and Statistical DNBR Evaluation Methodology. (See Section 3.4.3.2.) The DNB limits applicable for use in the COBRA code with the W-3 and WRB-l correlations are listed in Table 3.2-1 for application with the deterministic and statistical DNB methodologies.

The DNB analysis of the Westinghouse 15 x 15 Upgrade is based on the Statistical DNBR Evaluation Methodology (Reference 1), the VIPRE-D code (Reference 6), and the WRB-1 DNB correlation (Reference 6) as submitted to the NRC in Reference 7, and approved by the NRC in References 8 and 9. The W-3, ABB-NV, or WLOP DNB correlations and a deterministic treatment of key DNBR analysis uncertainties are used when any of the conditions are outside the range of the WRB-l DNB correlation and Statistical DNBR Evaluation Methodology. (See Section 3.4.3.2.) The DNB limits applicable for use in the VIPRE-D code with the WRB-1, W-3, ABB-NV, and WLOP correlations are listed in Table 3.2-1 for application with the deterministic and statistical DNB methodologies.

Additional information on thermal/hydraulic design can be found in Section 3.4.

3.2.3.4 **Mechanical Limits**

3.2.3.4.1 Reactor Internals

The reactor internal components are designed to withstand the stresses resulting from start-up, steady-state operation with any number of pumps running, and shutdown conditions. No damage to the reactor internals occurs as a result of loss of pumping power.

Lateral deflection and torsional rotation of the lower end of the core barrel are limited to prevent excessive movements resulting from seismic disturbances, thus preventing interference with control rod assemblies. Core drop in the event of failure of the normal supports is limited so that the control rod assemblies do not disengage from the fuel assembly guide thimbles.

The structural components are designed to maintain their functional integrity in the event of a major loss-of-coolant accident (LOCA). The dynamic loading resulting from the pressure oscillations because of a LOCA does not prevent insertion of the control rod assemblies.

Seismic design criteria for the reactor internals are discussed in Appendix 15A. Additional information on mechanical design can be found in Section 3.5.

3.2.3.4.2 Fuel Assemblies

The fuel assemblies are designed to perform satisfactorily throughout their required lifetime. The loads, stresses, and strains resulting from the combined effects of flow-induced vibrations, earthquakes, reactor pressure, fission gas pressure, fuel growth, thermal strain, and differential expansion during both steady-state and transient reactor operating conditions have been considered in the design of the fuel rods and fuel assembly. The assembly is also structurally designed to withstand handling and shipping loads prior to irradiation, and to maintain sufficient integrity at the completion of design burnup to permit safe removal from the core, handling, shipment, and fuel reprocessing.

The fuel rods are supported at several locations along their length within the fuel assemblies by brazed or welded grid assemblies, which are designed to maintain control of the lateral spacing between the rods throughout the design life of the assemblies. The magnitude of the support loads provided by the grids is established to minimize possible fretting without overstressing the cladding at the points of contact between the grids and fuel rods, and without imposing restraints of sufficient magnitude to result in buckling or distortion of the rods.

The fuel rod cladding is designed to withstand operating pressure loads without rupture, and to maintain encapsulation of the fuel throughout its design life.

3.2.3.4.3 Control Rod Assemblies

The criteria used for the design of the cladding on the individual control rods in the control rod assemblies are similar to those used for the fuel rod cladding. The cladding is designed to be free-standing under all operating conditions and to maintain encapsulation of the absorber material throughout the control rod design life. Allowance for wear during operation is included for the control rod cladding thickness.

Adequate clearance is provided between the control rods and the guide thimbles that position the rods within the fuel assemblies so that coolant flow along the length of the control rods is sufficient to remove the heat generated without overheating of the absorber cladding. The clearance is also sufficient to compensate for any misalignment between the control rods and guide thimbles and to prevent mechanical interference between the rods and guide thimbles under any operating condition.

3.2.3.4.4 Control Rod Drive Mechanisms

Each control rod drive mechanism is designed as a hermetically sealed unit to prevent leakage of reactor coolant water. All pressure-containing components are designed to meet the requirements of ASME Code Section III for Class A vessels.

The control rod drive mechanisms for the control rod assemblies provide control rod assembly insertion and withdrawal rates consistent with the required reactivity changes for reactor operational load changes. This rate is based on the worths of the various rod groups, which are established to limit power-peaking flux patterns. The maximum reactivity addition rate is specified to limit the magnitude of a possible nuclear excursion resulting from a control system or operator malfunction. Also, the control rod drive mechanisms provide a fast insertion rate during a trip of the control rod assemblies, which results in a rapid shutdown of the reactor for conditions that cannot be handled by the reactor control system.

3.2 REFERENCES

1. R. C. Anderson, *Statistical DNBR Evaluation Methodology*, VEP-NE-2-A, June 1987.
2. F. W. Sliz and K. L. Basehore, *Vepco Reactor Core Thermal-Hydraulic Analysis Using the COBRA-IIIC/MIT Computer Code*, VEP-FRD-33-A, October 1983.
3. R. C. Anderson and N. P. Wolfhope, *Qualification of the WRB-1 CHF Correlation in the Virginia Power Cobra Code,* VEP-NE-3-A, July 1990.
4. Letter from W. L. Stewart (Virginia Power) to NRC, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Proposed Technical Specification Changes, F Delta H Increase/Statistical DNBR Methodology*, Serial No. 91-374, July 8, 1991.
5. Letter from B. C. Buckley (NRC) to W. L. Stewart (Virginia Electric and Power Company), *Surry Units 1 and 2 - Issuance of Amendments Re: F Delta H Limit and Statistical DNBR Methodology*, Serial No. 92-405, June 1, 1992.
6. B. L. Mount, *Reactor Core Thermal-Hydraulics Using the VIPRE-D Computer Code*, DOM-NAF-2-P-A, Rev. 0.3, September 2014.
7. Letter from J. A. Price (Dominion) to NRC, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Proposed License Amendment Request, Relocation of Core Operating Limits to the Core Operating Limits Report (COLR) and Addition of COLR References*, Serial No. 09-581, October 16, 2009.
8. Letter from K. Cotton (NRC) to D. A. Heacock, *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Request for Technical Specification Revisions Related to the Core Operating Limits Report (TAC Nos. ME2591 and ME2592)*, Serial No. 10-645, October 19, 2010.
9. Letter from K. Cotton (NRC) to D. A. Heacock, *Surry Power Station, Unit Nos. 1 and 2, Correction to Amendments Regarding Technical Specification Revisions Related to the Core Operating Limits Report (TAC Nos. ME2591 and ME2592)*, Serial No. 10-648, October 21, 2010.

Table 3.2-1
DNBR LIMITS

Limits for 15 x 15 SIF Fuel			
Code	Correlation	Limit Type[1]	Limit Value
COBRA	W-3	DDL (≥1,000 psia)	1.30
		SAL (≥1,000 psia)	1.44
		Retained DNBR Margin (≥1,000 psia)	9.7%
		DDL (<1,000 psia)	1.45
		SAL (<1,000 psia)	1.45
		Retained DNBR Margin[2] (<1,000 psia)	13.3%
	WRB-1	DDL	1.17
		SAL	1.46
		Retained DNBR Margin	19.9%
		SDL	1.27
		SAL	1.46
		Retained DNBR Margin	13.0%

1. DDL is the Deterministic Design Limit. This is also known as the code/correlation limit.
SDL is the Statistical Design Limit.
SAL is the Safety Analysis Limit.
Retained Margin is equal to the margin between the design limit and the safety analysis limit in percent of the safety analysis limit.

$$\textit{Retained Margin [\%]} = \left(\frac{SAL - DDL}{SAL}\right)$$

2. The retained DNBR margin for this case (i.e., MSLB for 15 x 15 SIF) consists of several components of generic retained margin which existed as a consequence of excessively conservative choices for variables or modeling features for which a DNB credit has been quantified.

Table 3.2-1 (continued)
DNBR LIMITS

Limits 15 x 15 Upgrade Fuel			
Code	Correlation	Limit Type[1]	Limit Value
VIPRE-D	W-3	DDL (≥1,000 psia)	1.30
		SAL (≥1,000 psia)	1.44
		Retained DNBR Margin (≥1,000 psia)	9.7%
		DDL (≤1,000 psia)	1.45
		SAL (≤1,000 psia)	1.61
		Retained DNBR Margin (≤1,000 psia)	9.9%
	WRB-1	DDL	1.17
		SAL	1.52
		Retained DNBR Margin	23.0%
		SDL	1.27
		SAL	1.52
		Retained DNBR Margin	16.4%
	ABB-NV	DDL	1.14
		SAL	1.40
		Retained DNBR Margin	18.5%
	WLOP	DDL	1.22
		SAL	1.40
		Retained DNBR Margin	12.8%

1. DDL is the Deterministic Design Limit. This is also known as the code/correlation limit.
SDL is the Statistical Design Limit.
SAL is the Safety Analysis Limit.
Retained Margin is equal to the margin between the design limit and the safety analysis limit in percent of the safety analysis limit.

$$\textit{Retained Margin [\%]} = \left(\frac{SAL - DDL}{SAL}\right)$$

Table 3.2-2
UFSAR TRANSIENTS ANALYZED USING DETERMINISTIC AND STATISTICAL METHODS

Accident	SPS USAR Section	Application
Uncontrolled Control-Rod Assembly Withdrawal From a Subcritical Condition	14.2.1	DET-DNB[1]
Uncontrolled Control-Rod Assembly Withdrawal at Power	14.2.2	STAT-DNB[2]
Control-Rod Assembly Drop/Misalignment	14.2.4	STAT-DNB
Chemical and Volume Control System Malfunction	14.2.5	Non-DNB[3]
Start-Up of an Inactive Loop (SUIL) Accident Analysis Design Basis	14.2.6	Non-DNB
Excessive Heat Removal Due to Feedwater System Malfunctions	14.2.7	STAT-DNB
Excessive Load Increase Incident	14.2.8	STAT-DNB
Loss of Reactor Coolant Flow	14.2.9.1	STAT-DNB
Locked Rotor Incident	14.2.9.2	STAT-DNB
Loss of External Electrical Load	14.2.10	STAT-DNB
Loss of Normal Feedwater	14.2.11	Non-DNB
Loss of All Alternating Current Power to the Station Auxiliaries	14.2.12	Non-DNB
Rupture of a Main Steam Pipe	14.3.2	DET-DNB

1. DET-DNB means that deterministic DNBR methods are used for this event.
2. STAT-DNB means that statistical DNBR methods are used for this event.
3. Non-DNB means that this DNB is not a limiting criterion for this event.

3.3 NUCLEAR DESIGN

This section discusses the nuclear characteristics of the core, and evaluates the characteristics and design parameters that are significant with respect to the design objectives (Section 3.2.1). These evaluations demonstrate the capability of the reactor to achieve these objectives while performing safely under all steady-state and transient operational modes.

3.3.1 Reactivity Control Aspects

Reactivity control is provided by boron dissolved in the reactor coolant, movable neutron-absorbing control rod assemblies, fixed burnable poison rods, and/or integral fuel burnable absorber (IFBA).

The concentration of soluble boron is varied as necessary during the life of the core to compensate for changes in reactivity that occur with changes in temperature of the reactor coolant from cold shutdown to hot operating conditions, changes in reactivity associated with inventory changes in the fission product poisons xenon and samarium, reactivity losses associated with the depletion of fissile inventory and buildup of long-lived fission product poisons, and changes in reactivity due to burnable poison burnup.

The control rod assemblies provide reactivity control for: fast shutdown, reactivity changes associated with changes in the average coolant temperature above hot-zero-power temperature (since core average coolant temperature is increased with power level), reactivity associated with any void formation, and reactivity changes associated with the power coefficient of reactivity.

The control rod assemblies are divided into two categories according to their function. Thirty-two control rod assemblies compensate for changes in reactivity due to variations in operating conditions of the reactor, such as power or temperature. They are divided into four control groups or banks, each consisting of eight assemblies. Sixteen control rod assemblies provide additional shutdown reactivity, and are termed shutdown assemblies. The total shutdown worth of all the control rod assemblies is specified to provide adequate shutdown with the most reactive assembly stuck out of the core.

Burnable poison (fixed burnable poison rods and/or IFBA) provides control of part of the excess reactivity available during the core cycle. The primary function of burnable poison is to prevent the moderator temperature coefficient from being positive, under normal operating conditions, by reducing the soluble boron content of the reactor coolant at the beginning of life, as described in WCAP-7113 (Reference 1). The number and location of fixed burnable poison rods for the first core cycle is shown in Figure 3.3-1. The use of burnable poison in subsequent cycles is discussed in Section 3.3.3.2.2.

Since the presence of control rod assemblies and burnable poison influences flux shape in the core, it is pertinent to summarize some typical fission power density distributions. Figures 3.3-2 and 3.3-3 illustrate X-Y power density distributions for rodded and unrodded conditions. The value of F_{xy} shown on each figure indicates the ratio of maximum power density to average power density.

3.3.2 Nuclear Design Data

The values of design parameters cited in this section and in Tables 3.3-1 through 3.3-3 generally pertain to the first Surry core cycle. The pertinent nuclear design data for each subsequent cycle of operation are contained in a reload safety evaluation prepared by Vepco prior to cycle start-up. The reload safety evaluation process involves an evaluation of the reload core during which the values of kinetics parameters, fuel temperatures, peaking factors, and core limits used in the currently applicable safety analysis are compared with corresponding values for the planned reload cycle. Where the evaluation shows parametric values for the planned cycle that are outside the bounds of the previous safety analysis, the specific accident analyses sensitive to these parameters are reevaluated or reanalyzed. If a reanalysis leads to Technical Specification changes, these are obtained from the NRC, also prior to cycle start-up.

3.3.2.1 **Core Reactivity Characteristics**

A summary of nuclear design data for the first cycle only, including core reactivity characteristics, is presented in Table 3.3-1. Discussion of the table is facilitated by use of line numbers. A summary of reactivity requirements and control rod worth is given in Tables 3.3-2 and 3.3-3, which may be used in conjunction with Table 3.3-1.

General structural characteristics are given in lines 1 through 10 of Table 3.3-1, while performance characteristics are listed in lines 11 through 22. Typical values of effective neutron multiplication constants and estimated critical boron (chemical shim) concentrations are listed for specified conditions in lines 23 through 41. Several of these items, such as soluble boron control, are discussed in greater detail below.

Adequate control to render the reactor subcritical at temperatures below the operating range is provided by the soluble boron concentration. The boron concentration during refueling, reported in line 32 of Table 3.3-1, based on all the control rod assemblies being inserted, provides approximately 10% delta k/k shutdown margin.[1] This concentration is also sufficient to maintain the core subcritical with no control rod assemblies inserted in the core. This is consistent with General Design Criteria No. 26 (GDC-26), which states that one of two independent reactivity control systems "shall be capable of holding the reactor core subcritical under cold conditions." For cold shutdown at the beginning of core life, the concentration shown in Table 3.3-1, line 40, is sufficient for 1% delta k/k shutdown with all but the maximum-worth control rod assembly inserted.

The boron concentration for refueling is equivalent to less than 2% by weight boric acid (H_3BO_3), and is well within solubility limits at ambient temperature. This concentration is also

1. The text applies to the initial core cycle; see Technical Specifications for current shutdown requirements.

maintained in the spent-fuel pool, since it is directly connected with the refueling canal during refueling operations.

The initial full-power boron concentration without equilibrium xenon and samarium is shown in line 37 of Table 3.3-1. As these fission product poisons are built up, the boron concentration is reduced. This initial boron concentration assumes no full-length rod insertion. The xenon-free, zero-power shutdown, k = 0.99[1] or less, with all but the maximum-worth control rod assembly inserted, is maintained with the boron concentrations shown in lines 40 and 41, for the cold and hot conditions, respectively.

The boron concentrations given above are representative of those during the first operating cycle where burnable poison rods and the associated worth listed in lines 42, 43, and 44 were present. Core kinetic characteristics are dependent on boron concentrations, and the presence of burnable poison rods and control rods. A discussion of these factors follows.

3.3.2.2 **Kinetic Characteristics**

The response of the reactor core to unit conditions or operator adjustments during normal operation, as well as the response during abnormal or accidental transients, is determined by means of a detailed simulation. In these calculations, reactivity coefficients are required to couple the response of the core neutron multiplication to the variables that are set by conditions external to the core. Since the reactivity coefficients change during the life of the core, a range of coefficients is established to determine the response of the unit throughout life and to establish the design of the reactor control and protection system.

3.3.2.3 **Moderator Temperature Coefficient**

The moderator temperature coefficient in a core controlled by soluble boron is less negative than the coefficient in an equivalent rodded core. One reason is that control rods contribute a negative increment to the coefficient, and in a core using soluble boron, the control rods are only partially inserted. Also, the boron concentration is decreased with the decrease in water density upon an increase in temperature. This gives rise to a positive component of the moderator temperature coefficient due to the removal of boron from the core. This effect is directly proportional to the amount of reactivity controlled by the dissolved boron.

To reduce the soluble boron requirement for control of excess reactivity, burnable poison rods and/or IFBA rods are incorporated in the core design. The effect of reducing the soluble boron concentration is to make the moderator temperature coefficient more negative. This is caused by a reduction of the effect that coolant temperature and density changes have on the boron number density in the core.

The burnable poison rods for the initial core were borated glass tubes clad in stainless steel. Clusters of these rods were distributed throughout the core in vacant control rod guide thimbles.

1. The text applies to the initial core cycle; see Technical Specifications for current shutdown requirements.

The initial core pattern is shown in Figures 3.3-1 and 3.3-4 on a gross core and an assembly-wise basis, respectively. Information regarding research, development, and nuclear evaluation results of the burnable poison rods can be found in WCAP-7113 (Reference 1) and WCAP-9000 (Reference 2). The number of rods and the corresponding reactivity worth at beginning of life of the initial cycle are indicated in lines 42, 43, and 44 of Table 3.3-1.

Typically, the moderator temperature coefficient is negative at operating temperatures. The coefficient becomes more negative with increasing burnup, as a result of build-up of plutonium and fission products and reduction of the boron concentration. The reactivity loss due to equilibrium xenon is controlled by reduction of boron concentration. As xenon builds up, the boron concentration is reduced. The calculated range of the moderator temperature coefficient from beginning of life to end of life of the initial cycle is shown in line 45.

The control rods provide a negative contribution to the moderator coefficient. This is indicated in Figure 3.3-5, which shows a typical relationship between moderator temperature and moderator temperature coefficient, both with and without rods.

Design calculations for Surry reload cycles subsequent to cycle 1 have shown that the moderator temperature coefficient may be positive at the beginning of a cycle, with hot zero-power conditions and all rods out. Although control rod insertion can be used to bring the coefficient negative, this would lengthen the plant start-up after a refueling and would make the start-up more complex by requiring restrictions on boron concentration and control rod movement. Therefore, to facilitate start-up, it is desirable to allow a slightly positive moderator temperature coefficient at lower power levels. As the power level is raised, the average core water temperature becomes higher, as allowed by the programmed average temperature for the plant, tending to bring the moderator coefficient more negative. Also, the boron concentration can be reduced as xenon builds into the core. Thus, there is less need to allow a positive coefficient as full power is approached. As fuel burnup is achieved, boron is further reduced and the moderator coefficient becomes negative over the entire operating power range.

The impact of a positive moderator temperature coefficient on the accident analyses presented in Chapter 14 has been assessed. Any incident which was found to be sensitive to minimum or near-zero moderator coefficients was reanalyzed. In general, reanalysis was based on the assumptions and methods employed in the original accident analysis, with exceptions noted in the discussion of each incident in Chapter 14. Accidents not reanalyzed included those resulting in excessive heat removal from the reactor coolant system for which a large negative moderator coefficient is conservative, and those for which the moderator coefficient is assumed to be negative due to control rod insertion resulting from reactor trip.

The Technical Specifications allow a constant positive moderator temperature coefficient below 50% of rated power, decreasing linearly to zero at 100% of rated power. This provides ample operating flexibility and allows a reasonable degree of flexibility in core design and plant operation for future cycles.

A requirement that the reactor is not to be made critical with a reactor coolant temperature below 538°F is imposed to provide added assurance that the assumptions made in the safety analysis remain bounding by maintaining the moderator temperature within the range of those analyses.

The positive moderator temperature coefficient will exist for only a short time at beginning of cycle, and the Technical Specifications require the maximum upper limit of the MTC coefficient to be zero at full power. Operating with a positive moderator temperature coefficient is acceptable as long as plant operation is limited in accordance with the values of cycle-specific parameter limits that are established using NRC-approved methodologies.

3.3.2.4 **Moderator Pressure Coefficient**

The moderator pressure coefficient has a sign opposite to the moderator temperature coefficient. The net effect of the moderator pressure coefficient on the total coefficient is small because of the small magnitude of the pressure coefficient, since a change of 50 psi in pressure has no more effect on reactivity than a half-degree change in moderator temperature. The calculated initial-core beginning-of-life and end-of-life pressure coefficients are shown in Table 3.3-1, line 46.

3.3.2.5 **Moderator Density Coefficient**

A uniform moderator density coefficient is defined as a change in the neutron multiplication per unit change in moderator density. The range of the moderator density coefficient from beginning to end of life of the initial core is specified in Table 3.3-1, line 47.

3.3.2.6 **Doppler and Power Coefficients**

The calculation of power coefficients in a large, slightly enriched core is complex. As fuel pellet temperature increases with power density, the resonance absorption in U-238 increases as a result of Doppler broadening of the resonances. The relationship between effective fuel temperature and resonance absorption in a fuel rod is sufficiently complex in itself. An additional degree of complexity is introduced in relating these resonance-broadening effects to actual operation of the core, in which non-uniform power and fuel temperature distributions are subject to continual change with control rod movements, fuel burnup, and varying heat transfer characteristics of the fuel rods.

The Doppler reactivity coefficient is defined as the change in neutron multiplication per degree change in the effective fuel temperature, delta k/k/°F. The variation in this quantity with effective fuel temperature is shown in Figure 3.3-6, as computed by the LEOPARD code (Reference 3). It may be observed that the Doppler coefficient is non-linear and becomes less negative as temperature increases. The integral under the curve between the effective fuel temperature associated with the hot-zero-power condition and that associated with full power represents the Doppler reactivity defect.

To obtain the integral or differential change in core reactivity with power, it is necessary to know the change in effective fuel temperature with power, delta T/delta P, as well as the Doppler coefficient, delta k/k/°F. An empirical approach is taken to calculate the behavior of delta T/delta P with power, based on operating experience of Westinghouse cores. Results obtained with this approach are illustrated in Figure 3.3-7, which shows reactivity effects associated with Doppler broadening only. (The results presented do not include any moderator coefficient, even though the moderator temperature changes with core power level.)

In the empirical model used above, a large temperature drop is assumed to occur across the fuel pellet-clad gap. Under conditions where this gap may be essentially "closed," the fuel temperature for a given power level, and the quantity delta T/delta P, may be significantly reduced. At a lower effective fuel temperature, the Doppler reactivity defect is reduced; however, the Doppler coefficient is more negative. The net effect of using a closed-gap model is a power coefficient that shows much less variation with power than that shown with a gap model. Results obtained using this model are shown in Figure 3.3-8, where it may be observed that the power coefficient at full power is similar to that obtained with the gap model.

The above discussion relates primarily to reactivity characteristics on a core basis. A similar situation exists with regard to local Doppler reactivity feedback characteristics, which are important in determination of the stability of the reactor to xenon oscillations. Calculations indicate that local reactivity feedback in the range of interest for stability (50% to 150% of core average power density) is relatively insensitive to the thermal model.

3.3.2.7 **Summary of Control Rod Requirements**

Figure 3.3-9 depicts the functional grouping and designation of the control rod assemblies.

Reactivity requirements of control rods at beginning and end of life are summarized in Table 3.3-2. The requirements, discussed below, include those that are associated with shutdown conditions.

3.3.2.8 **Total Power Defect**

Control rods must be available to compensate for the reactivity change incurred with a change in power level due to the Doppler effect. The magnitude of this change has been established by correlating the experimental results of numerous operating cores.

The average temperature of the reactor coolant increases with power level in the reactor. Since this increase in coolant temperature is actually a part of the power-dependent reactivity change, along with the Doppler effect and void formation, the associated reactivity change must be controlled by rods. The largest amount of reactivity that must be controlled is at the end of life, when the moderator temperature coefficient has its most negative value. The moderator temperature coefficient range for the initial cycle is given in Table 3.3-1, line 45, while the cumulative reactivity change is shown in the first line of Table 3.3-2. By the end of each fuel cycle, the non-uniform axial depletion causes a severe power peak at lower power. The reactivity associated with this peak is part of the power defect.

3.3.2.9 **Operational Maneuvering Band**

Each control rod assembly control group is operated at power within a prescribed band of travel in the core to compensate for periodic changes in boron concentration, temperature, and pressure. The band has been defined as the operational maneuvering band. When the control rod assemblies reach either limit of the band, a change in boron concentration must be made to compensate for any additional change in reactivity.

3.3.2.10 **Control Rod Bite**

For good response to rapid changes in load, the control groups of control rod assemblies were originally positioned at a location that maintained a design minimum reactivity insertion rate. The partial control group insertion that was specified to provide the specified reactivity insertion rate is called control rod bite. The current analyses and design basis are met even when the unit is operated with all rods out of the core.

3.3.2.11 **Excess Reactivity Insertion Upon Reactor Trip**

Current control requirements are nominally based on providing 1.77% delta k/k shutdown at hot zero-power conditions, with the highest-worth control rod assembly assumed to be stuck in its fully withdrawn position.

3.3.2.12 **Calculated Rod Worths**

The control rod assemblies are arranged in a symmetric pattern as shown in Figure 3.3-9. Calculations are made to verify that the control rod worths are sufficient to meet the shutdown requirements. These worths are established assuming that the highest-worth control rod assembly is stuck in the fully withdrawn position. Table 3.3-3 lists the calculated worths for the beginning and end of the first cycle.

To be sure of maintaining a margin between calculated and required control rod worths, the calculated reactivity worths are decreased by 10% to account for any errors or uncertainties in the calculation.

A comparison between calculated and measured control rod worth shows the calculations to be well within the allowed uncertainty of 10%.

3.3.2.13 **Reactor Core Power Distribution**

In order to meet the performance objectives without violating safety limits, the peak to average power density must be within the limits set by the nuclear hot-channel factors. For the peak power point in the core at rated power, the nuclear heat flux hot-channel factor, F_q^N was established as specified in Table 3.3-1, line 21. For the hottest channel at rated power, the nuclear enthalpy rise hot-channel factors, $F^N_{\Delta H}$ was established as specified in Table 3.3-1, line 22. These values are specific to the initial cycle.

Power capability of a PWR core is determined largely by consideration of the power distribution and its interrelationship to limiting conditions involving:

1. The linear power density.
2. The fuel cladding integrity.
3. The enthalpy rise of the coolant.

To determine the core power capability, local as well as gross core neutron flux distributions have been determined for various operating conditions at different times in core life.

The presence of control rods, burnable poison, flux suppression inserts (Unit 1 only, Cycles 13 through 20) and chemical shim concentration all play significant roles in establishing the fission power distribution, in addition to the influence of thermal/hydraulic and temperature feedback considerations. The computer programs used to determine neutron flux distributions include a model to simulate non-uniform water (and chemical shim) density distributions.

Thermal/hydraulic feedback considerations are especially important late in cycle life, when the magnitude of the flux redistribution and reactivity change with change in core power or control rod assembly movement are strongly influenced by enthalpy rise up the core and by the fuel burnup distribution. Consequently, extensive X-Y and Z power distribution analyses are performed to evaluate fission power distributions. Typical X-Y power distributions are presented in Figures 3.3-2 and 3.3-3 to illustrate the combined effect of a control rod assembly group upon assembly average power density. Incore instrumentation is employed to evaluate the core power distributions throughout core lifetime to ensure that the thermal design criteria are met.

The Ex-Core Nuclear Instrumentation System supplies the necessary information for the operator to control the core power distribution within the limits established for the protection system design. This information consists of a multipen recorder, which displays the upper and lower ion chamber signals, and an indicator that gives the difference in these two signals for each long ion chamber. These ion chamber signals to the recorders and indicators are calibrated against incore power distribution obtained from the movable detector system generated in the adjacent section of the core. This essentially divides the core into eight sections, four in the upper half and four in the lower half.

The relationship between core power distribution and ex-core nuclear instrumentation readings was established during the start-up testing program (Chapter 13). Incore flux measurements were made for reactor power in the range of 25 to 100%. These measurements, together with long ion chamber currents, were processed to yield the relationships between core average axial power generation, axial peaking factor, and axial offset as indicated by the ex-core nuclear instrumentation. These relationships can be checked during operation to assess the effect of core burnup on the sensitivity between incore power distribution and ex-core readings.

The reactor core may be subject to axial xenon oscillations at the end of a fuel cycle life. The axial instability is due principally to the negative moderator temperature coefficient of reactivity that exists at end of life. Since the moderator coefficient at beginning of life is small, stability against axial oscillations is greatly increased at beginning of life. Consequently, stability margin experiments would not be informative at beginning of life.

A more detailed discussion of the background, analytical, and experimental data which form the basis for this approach is given in WCAP-7208 (Reference 4).

Ex-core neutron flux detectors were added to meet Regulatory Guide 1.97 and Appendix R requirements. These are discussed in Section 7.10.

3.3.3 Analytic Methods and Supporting Experimental Data

3.3.3.1 **Introduction**

The confidence in procedures and design methods for the initial core cycles was based on comparison of these methods with experimental results. The experiments included critical experiments performed at the Westinghouse Reactor Evaluation Center and other facilities, and also measured data from operating power reactors. Extensive descriptions of these analytic methods and the supporting experiment theory correlations are given in References 5 through 16. Discussion of these items may be found in other safety analysis reports on similar stations (e.g., the FSAR for Carolina Power and Light Company’s H. B. Robinson Unit No. 2, Docket No. 50-261).

The current core analysis methodology is described in the following section.

3.3.3.2 **Reload Methodology**

3.3.3.2.1 Introduction

Each reload core is evaluated to demonstrate that it will not adversely affect the safety of the plant. The evaluation is accomplished utilizing the methodology described in VEP-FRD-42-A, Rev. 2, MRev. 2 (Reference 17).

3.3.3.2.2 Core Description

The Surry cores consist of 157 fuel assemblies surrounded by a core baffle, barrel, and thermal shield, and enclosed in a steel pressure vessel. The pressure inside the vessel is maintained at a nominal 2250 psia. The coolant (and moderator) is pressurized water, which enters the bottom of the core at a nominal 540°F and undergoes a nominal average rise in temperature of 66°F before exiting the vessel. The average coolant temperature is 573.0°F and the average linear power density of the core is 6.6 kW/ft.

Each of the 157 fuel assemblies consists of 204 fuel rods (except fuel assemblies which have been reconstituted, see Section 3.5.2.1) arranged in a 15 x 15 square array. The fuel used in the Surry cores consists of slightly enriched uranium dioxide fuel pellets contained within a

Zircaloy-4, ZIRLO, or Optimized ZIRLO clad. A small gap containing pressurized helium exists between the pellets and the inner diameter of the clad. For the positions in the 15 x 15 array not occupied by fuel rods, there are 20 guide tube locations for fixed burnable poison rods, flux suppression inserts (Unit 1 only, Cycles 13 through 20), or control rods and one centrally located instrumentation tube. The fuel rods in each fuel assembly are supported by seven grids located along the length of the assembly. In the original Surry fuel design, all of these grids were fabricated from Inconel-718. In the Surry Improved Fuel (SIF) design, which was introduced in Cycle 10 (Batch 12) at each unit, the five middle grids on the assembly are made from zirconium-based alloy (Zircaloy-4 or ZIRLO). Inconel continues to be used for the top and bottom grids on the SIF fuel assemblies. These grids are mechanically attached to the guide tubes, which are, in turn, fastened to the upper and lower nozzles, and thus provide for assembly structural support. Beginning with the feed for Cycle 13 (Region 15), the Surry fuel assemblies also include an additional protective bottom Inconel grid, located directly above the bottom nozzle. This protective grid is a debris resistance feature, and is not considered an assembly structural component. Beginning in Cycle 21, each fuel assembly may contain from 0 to 148 integral fuel burnable absorber (IFBA) rods. The IFBA fuel rod design includes a thin layer of boride coating on the outer surface of the majority of the fuel pellets in the fuel rod, as well as axial blankets. The axial blanket is a six-inch (approximate) stack of slightly enriched annular fuel pellets without boride coating located at the top and bottom of the fuel stack in each IFBA rod. Cores may continue to use a limited number of discrete (fixed) burnable poison rod assemblies in conjunction with IFBA fuel assemblies, or may use IFBA fuel assemblies exclusively.

Beginning in Surry Unit 2 Cycle 31, all fuel rods in each new fuel batch may contain axial blankets. The axial blanket is a six-inch (approximate) stack of natural or slightly enriched fuel pellets (solid or annular) located at the top and bottom of the fuel stack in each fuel rod.

The 15 x 15 Upgrade fuel assembly design incorporates the following additional features vs. SIF fuel:

- three intermediate flow mixing grids (IFMs), made of ZIRLO, which improve flow mixing (IFMs are not credited for assembly structural support)
- balanced vane mid-grids, also made of ZIRLO, which reduce assembly vibration thus improving grid-to-rod fretting margin
- “tube-in-tube” guide thimble tubes which enhance dimensional stability against guide tube and assembly bowing and incomplete rod insertion
- Optimized ZIRLO fuel clad for improved corrosion resistance
- oxidation of the bottom portion of the fuel outer clad, including the bottom end plug and bottom end plug weldment, to improve debris resistance.

There are 48 rod cluster control assemblies (referred to as control rods) used to control core reactivity. The absorber material of the control rods is an alloy consisting of 80% silver, 15% indium, and 5% cadmium. The various control rods are arranged in and move in symmetrically located groups, or banks. Banks A, B, C, and D are denoted as the control banks and are moved in a fixed sequential pattern to control the reactor over the power range of operation. The remaining rods are denoted as shutdown banks and are used to provide shutdown margin.

In addition to the control rods, a chemical (boric acid) shim is used to control excess core reactivity and to facilitate operational flexibility. Above certain concentrations of chemical shim, burnable poison rods and/or integral fuel burnable absorber rods are also used to control excess reactivity. Burnable poison can also be used to shape (i.e., improve) the core power distribution. Discrete burnable poison rods contain borosilicate in the form of Pyrex glass clad in a stainless steel tube, or Al_2O_3 pellets in Zircaloy-4 tubes. Burnable poison rod assemblies, which may be used in any fuel assembly not under a control rod bank location, typically consist of clusters of either 8, 12, 16, or 20 rods that are inserted into the Zirconium-based alloy control rod guide tubes. IFBA fuel assemblies typically contain up to 148 IFBA rods symmetrically distributed throughout each assembly.

Flux suppression insert (FSI) assemblies were used in peripheral core locations in Unit 1 from Cycle 13 to Cycle 20 to suppress the neutron leakage flux in the radial and axial vicinity of reactor vessel weld locations. Each FSI contained twenty neutron absorber rods which were inserted into the fuel assembly guide thimble tubes. Each neutron absorber rod contained a hafnium stack encapsulated in thick walled Zircaloy cladding. The fast and thermal neutron flux in each fuel assembly with an FSI was reduced by reducing power through the insertion of negative reactivity. The active absorber region of the FSI assemblies was preferentially loaded toward the bottom of the active fuel region. By itself, this tended to skew the core average axial power distribution. To minimize this impact, some burnable poison rods with absorber removed from the bottom of the rodlets were used in Surry 1 cores with FSIs. Removal of the absorber had the effect of a positive reactivity insertion, which offset some of the axial impact of the FSIs. Other than the use of less absorber material and biasing the location of the poison stack toward the top of the fuel stack, these short burnable poison assemblies were mechanically identical to other current burnable poison assemblies.

Flux suppression inserts were removed from the Unit 1 core following operation of Cycle 20 and after approval of a revised methodology to assess the impact of fluence on vessel welds. When the FSIs were removed from the core, the use of shorter burnable poison assemblies was eliminated.

3.3.3.2.3 Conclusions

The effect of a given reload on previously acceptable safety limits is documented in a reload safety evaluation report. The report addresses the mechanical, nuclear, and thermal/hydraulic design of the reload core, and provides references wherein more detailed supporting information can be found.

3.3 REFERENCES

1. P. M. Wood, E. A. Bassler, P. E. MacDonald, and D. F. Paddleford, *Use of Burnable Poison Rods in Westinghouse Pressurized Water Reactors*, WCAP-7113, 1969.
2. Westinghouse Proprietary, *Nuclear Design of Pressurized Water Reactors with Burnable Poison Rods*, WCAP-9000, Revision 1, 1969.
3. R. F. Barry, *The Revised LEOPARD Code - A Spectrum Dependent Nonspatial Depletion Program*, WCAP-2759, March 1965.
4. Westinghouse Proprietary, *Power Distribution Control of Westinghouse Pressurized Water Reactors*, WCAP-7208, 1968.
5. L. W. Strawbridge, *Calculations of Lattice Parameters and Criticality for Uniform Water Moderated Lattices*, WCAP-3269-25, 1964.
6. W. J. Eich and W. P. Kovacik, *Reactivity and Neutron Flux Studies in Multiregion Loaded Cores*, WCAP-1433, 1961.
7. J. D. McGaugh and R. H. Chastain, *Power Density vs. Burnup Distribution in Yankee Core I*, WCAP-6051, 1963.
8. W. T. Sha, *An Analysis of Reactivity Worth of the Rod Cluster Control (RCC) Elements and Local Water Hole Power Density Peaking*, WCAP-3269-47, 1965.
9. C. G. Poncelet, *Effects of Fuel Burnup on Reactivity and Reactivity Coefficients in Yankee Core I*, WCAP-6055, 1963.
10. *Yankee Core Evaluation Program Quarterly Progress Report for the Period Ending June 30, 1963*, WCAP-6055, 1963.
11. E. Hellstrand and G. Lundgren, “The Resonance Integral for Uranium Metal and Oxide,” *Nuclear Science and Engineering*, Vol. 12, No. 435, 1962.
12. E. Hellstrand, *Journal of Applied Physics*, Vol. 28, No. 1493, 1957.
13. E. Hellstrand, P. Blomberg, and S. Horner, “The Temperature Coefficient of the Resonance Integral for Uranium Metal and Oxide,” *Nuclear Science and Engineering*, Vol. 8, No. 497, 1960.
14. A. Sauer, “Approximate Escape Probabilities,” *Nuclear Science and Engineering*, Vol. 16, No. 329, 1963.
15. K. M. Case, F. de Hoffman, and G. Plascek, *Introduction to the Theory of Neutron Diffusion*, 1953.
16. W. T. Sha, *An Experimental Evaluation of the Power Coefficient in Slightly Enriched PWR Cores*, WCAP-3269-40, 1965.

17. Nuclear Engineering Staff, *Reload Nuclear Design Methodology*, VEP-FRD-42-A, Rev. 2, MRev. 2, October 2017.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 3.3-1
TYPICAL NUCLEAR DESIGN DATA (INITIAL CORE)

Structural Characteristics	
1. Fuel weight (UO_2)	175,600 lb
2. Zircaloy weight	36,300 lb
3. Core diameter	119.7 in.
4. Core height	144 in.
Reflector Thickness and Composition	
5. Top - water plus steel	approximately 10 in.
6. Bottom - water plus steel	approximately 10 in.
7. Side - water plus steel	approximately 15 in.
8. H_2O/U volume ratio (cold)	4.18
9. Number of fuel assemblies	157
10. UO_2 rods per assembly	204
Performance Characteristics	
11. Heat output (initial rating)	2441 MWt
12. NSSS heat output (initial rating)	2449 MWt
13. NSSS heat output (corresponding to maximum calculated turbine rating)	2554 MWt
Fuel Burnup	
14. First cycle (average)	12,600 MWd/MTU
15. First core (average)	22,300 MWd/MTU
16. Design equilibrium batch average	31,500 MWd/MTU
Fuel Enrichment	
17. Weight percent (region 1)	1.85
18. Weight percent (region 2)	2.55
19. Weight percent (region 3)	3.10
20. Weight percent (equilibrium)	3.20

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 3.3-1 (CONTINUED)
TYPICAL NUCLEAR DESIGN DATA (INITIAL CORE)

Hot-Channel Factors	
21. Nuclear heat flux hot-channel factor, F_q^N	2.72
22. Nuclear enthalpy rise hot-channel factor, $F_{\Delta H}^N$	1.58
Control Characteristics	
Effective Multiplication (Beginning of Life) with Burnable Poison Rods	
23. Cold, no power, clean	1.176
24. Hot, no power, clean	1.145
25. Hot, full power, clean	1.124
26. Hot, full power, Xe and Sm equilibrium	1.090
Control Rod Assemblies	
27. Material	5% Cd - 15% In - 80% Ag
28. Full length	48
29. Partial length (removed from core)	5
30. Number of absorber rods per control rod assembly	20
31. Total rod worth, BOL	See Table 3.3-3
Boron Concentration	
32. Refueling shutdown, rods in (k=0.90)	2000 ppm
33. Shutdown (k=0.99) with rods inserted, clean, cold	780 ppm
34. Shutdown (k=0.99) with all rods inserted, clean, hot	370 ppm
35. Shutdown (k=0.99) with no rods inserted, clean, cold	1250 ppm
36. Shutdown (k=0.99) with no rods inserted, clean, hot	1240 ppm
37. Clean	1005 ppm[a]

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 3.3-1 (CONTINUED)
TYPICAL NUCLEAR DESIGN DATA (INITIAL CORE)

Boron Concentration (continued)	
38. Xenon equilibrium	740 ppm[a]
39. Xenon and samarium equilibrium	705 ppm[a]
40. Shutdown (k=0.99) all but one rod inserted, cold, clean	909 ppm
41. Shutdown (k=0.99) all but one rod inserted, hot, clean	509 ppm
Burnable Poison Rods	
42. Number and material of burnable poison rods	816 borated pyrex glass
43. BP worth, hot, delta k/k	6.9%
44. BP worth, cold, delta k/k	5.3%
Range of Kinetic Characteristics	
45. Moderator temperature coefficient (delta k/k)	$+0.3 \times 10^{-4}$ [b] to -3.5×10^{-4} per °F
46. Moderator pressure coefficient (delta k/k)	-0.3×10^{-6} to $+3.5 \times 10^{-6}$ per psi
47. Moderator density coefficient (delta k/k)	-0.1 to +0.3 per gm/cm^3
48. Doppler coefficient (delta k/k)	-0.1×10^{-5} to -1.6×10^{-5} per °F
49. Delayed neutron fraction	0.50 to 0.72%
50. Prompt neutron lifetime	2.5×10^{-5} sec
51. Moderator void coefficient (delta k/k)	$+0.5 \times 10^{-3}$ to -2.5×10^{-3} per % void

a. To control at hot full power, full length rods not inserted, k=1.0 (with burnable poison and part length rods in).
b. The positive coefficient does not occur at operating conditions (see Figure 3.3-5).

Table 3.3-2
TYPICAL REACTIVITY REQUIREMENTS FOR CONTROL RODS

Requirements	Percent delta k/k Beginning of Life	End of Life
Control		
Power defect (combined Doppler, T_{avg}, and void effects)	1.75	3.28
Operation maneuvering band	0.70	0.70
Control rod bite	0.10	0.10
Total Control	2.55	4.08

Note: Specific numerical values for a given fuel cycles are updated as necessary in the associated reload safety evaluation report.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

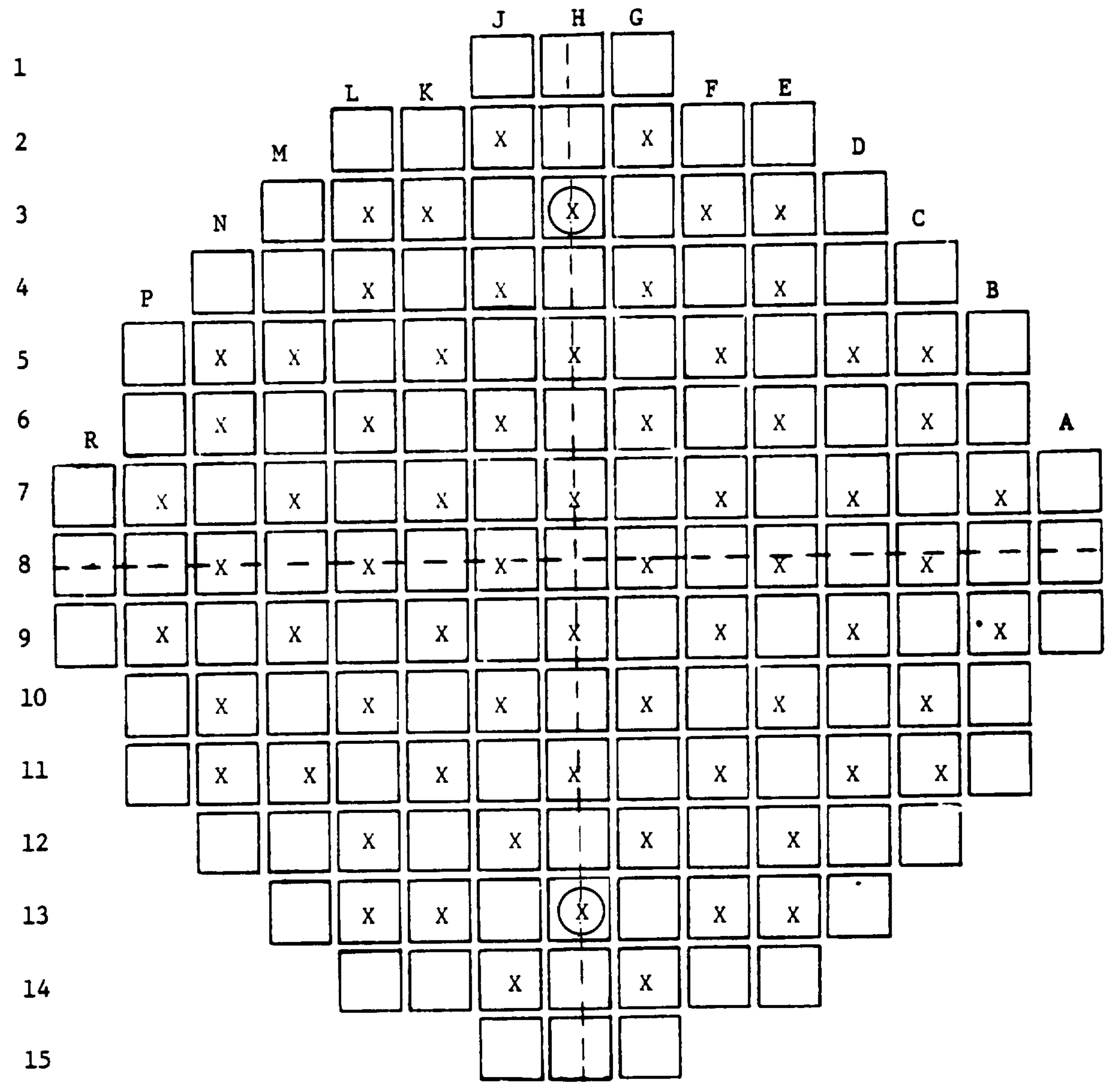
Table 3.3-3
TYPICAL CONTROL ROD WORTHS (DELTA k/k)

Core Conditions[a]	Rod Configurations	Percent Worth	Less 10%[b]	Design Reactivity Requirements	Shutdown Margin
BOL, HFP	48 rods in	10.05			
	47 rods in; highest-worth rod stuck out	8.85	7.96	2.55	5.41
EOL, HFP (1st cycle)	48 rods in	9.83			
	47 rods in; highest-worth rod stuck out	8.11	7.30	4.08	3.22
EOL, HFP (3rd cycle)	48 rods in	8.57			
	47 rods in; highest-worth rod stuck out	6.52	5.87	4.08	1.79

Note: Specific numerical values for a given fuel cycle are updated as necessary in the associated reload safety evaluation report.

a. BOL = beginning of life.
EOL = end of life.
HFP = hot full power.
b. Calculated rod worth is reduced by 10% to allow for uncertainties.

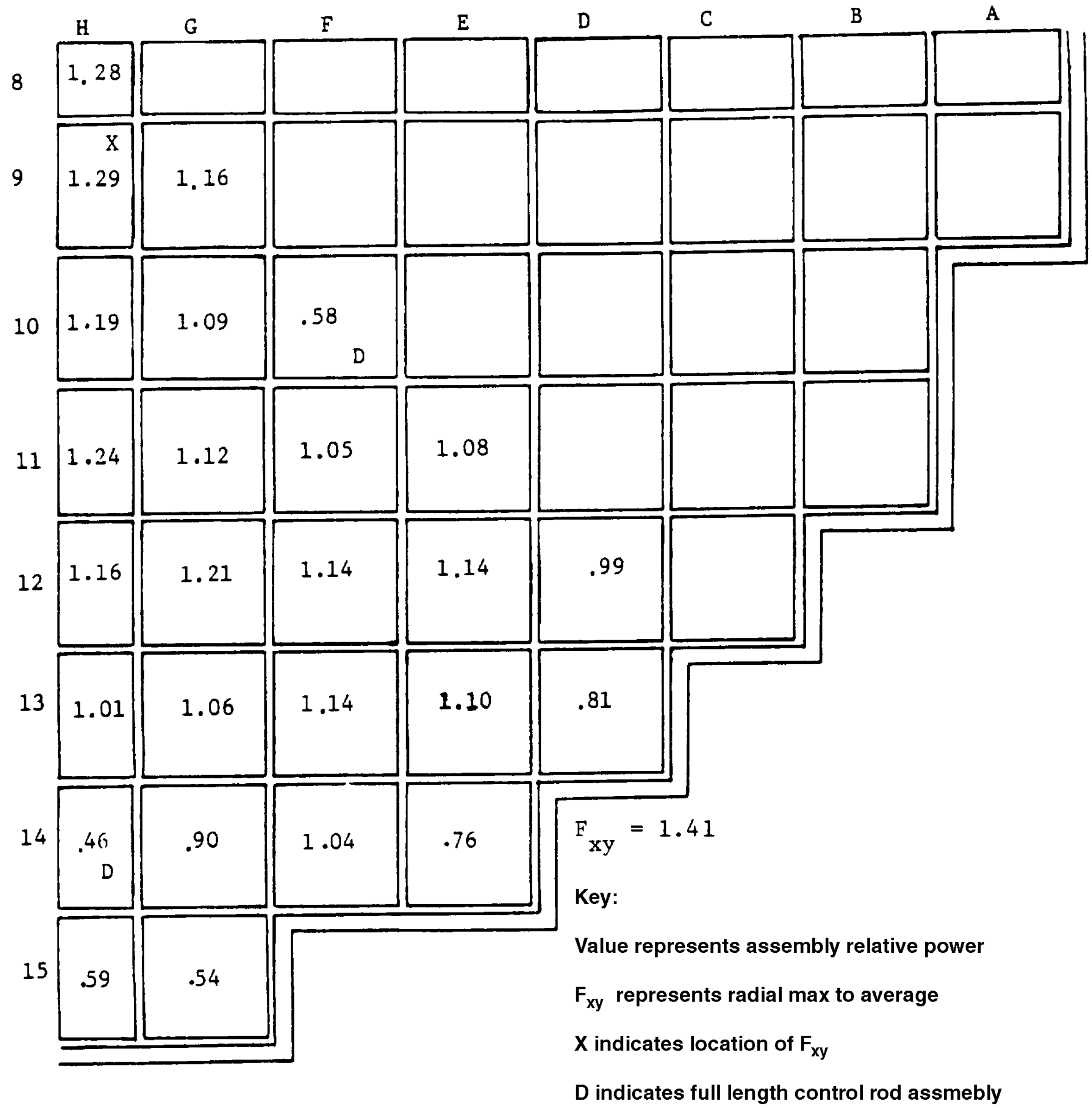
Figure 3.3-1
CYCLE 1 BURNABLE POISON CLUSTER LOCATIONS



Total Number of Clusters 68
Total Number of Rods 816
◯ = Primary Source Assembly Locations

X - Indicates Fuel Assembly Having a Burnable Poison Cluster of 12 rods

Figure 3.3-2
NORMALIZED POWER DENSITY DISTRIBUTION AT BEGINNING OF LIFE,
GROUP D INSERTED, HOT FULL POWER, NO XENON



S0303002

Figure 3.3-3
NORMALIZED POWER DENSITY DISTRIBUTION AT BEGINNING OF LIFE, UNRODDED CORE, HOT FULL POWER, NO XENON

	H	G	F	E	D	C	B	A
8	1.15							
9	1.20	1.15						
10	1.14	1.18	1.11					
11	1.17	1.11	1.12	1.02				
12	1.10	1.13	1.04	.98	.80			
13	1.13	1.07	1.02	.92	.65			
14	1.03	X 1.08	.98	.65				
15	.90	.70						

F_{xy} = 1.33

Value represents assembly relative power

F_{xy} represents radial max to average

X indicates location of F_{xy}

S0303003

Figure 3.3-4
ARRANGEMENT OF BURNABLE POISON RODS WITHIN AN ASSEMBLY

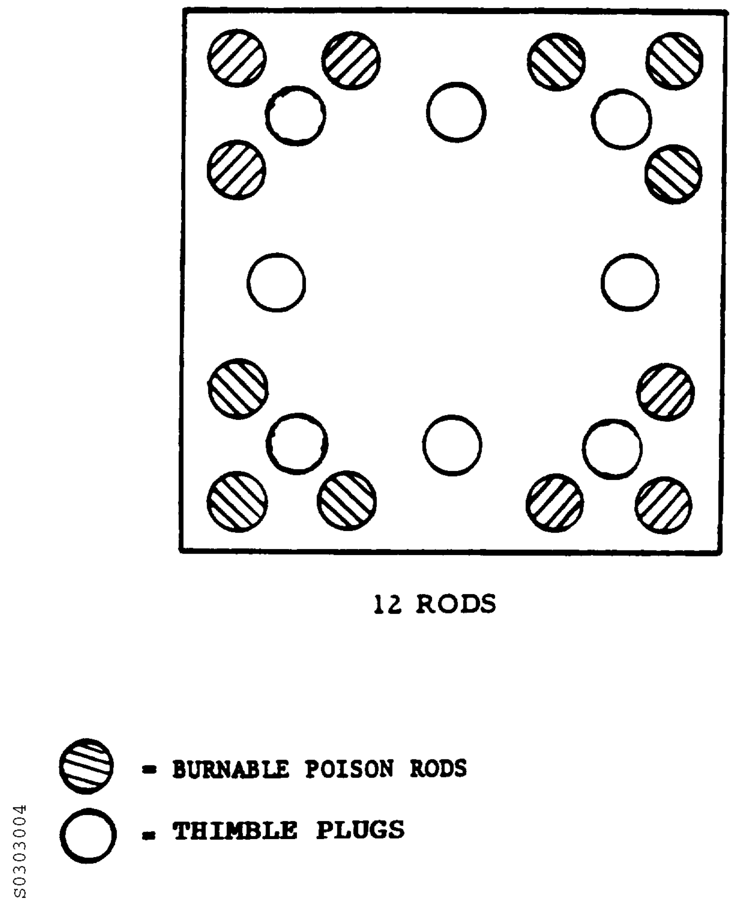
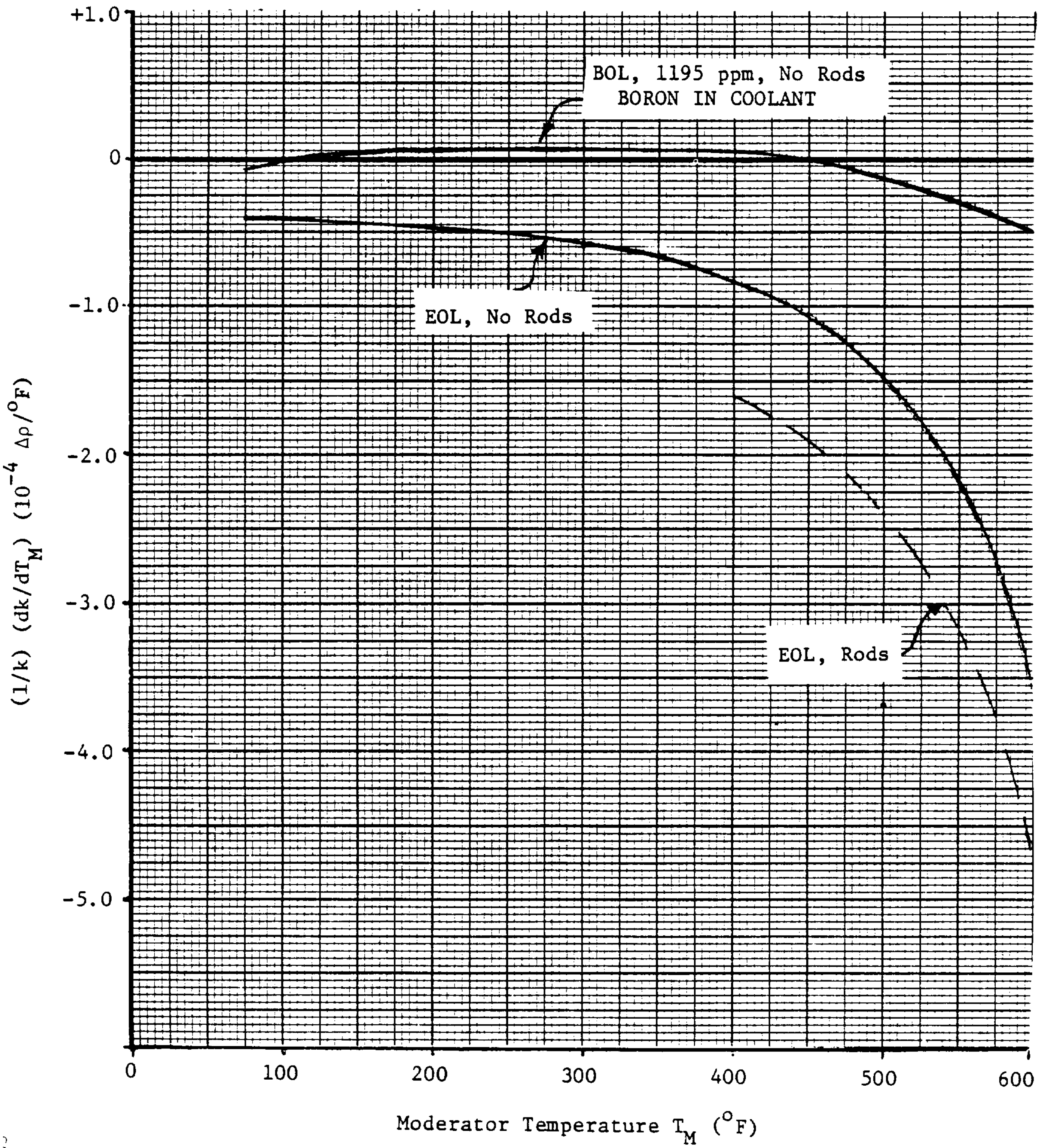


Figure 3.3-5
MODERATOR TEMPERATURE COEFFICIENT VS. MODERATOR TEMPERATURE



EOL = END OF LIFE
BOL = BEGINNING OF LIFE

Figure 3.3-6
DOPPLER COEFFICIENT VS. EFFECTIVE FUEL TEMPERATURE (BOL)

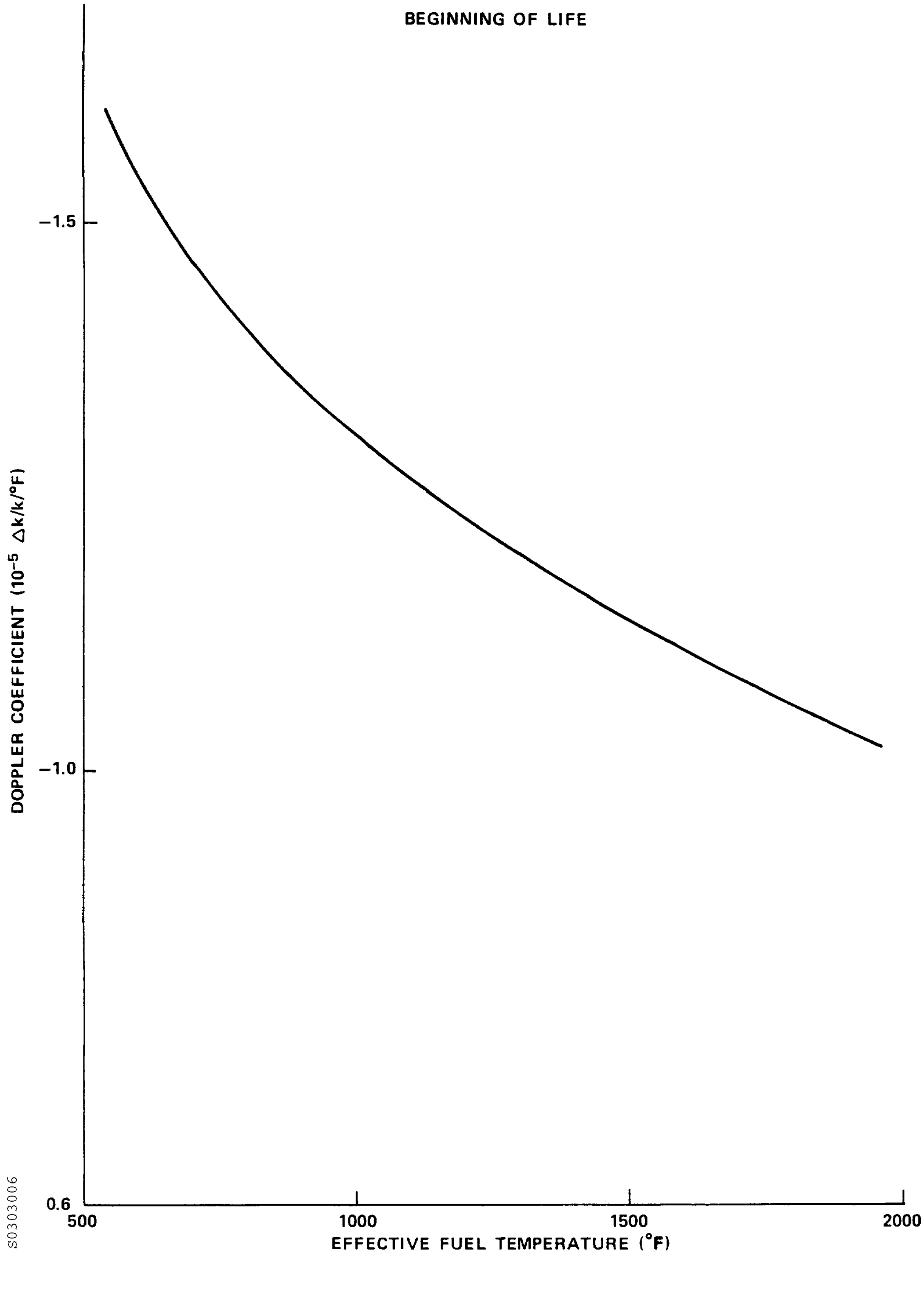


Figure 3.3-7
POWER COEFFICIENT (AIR GAP MODEL)

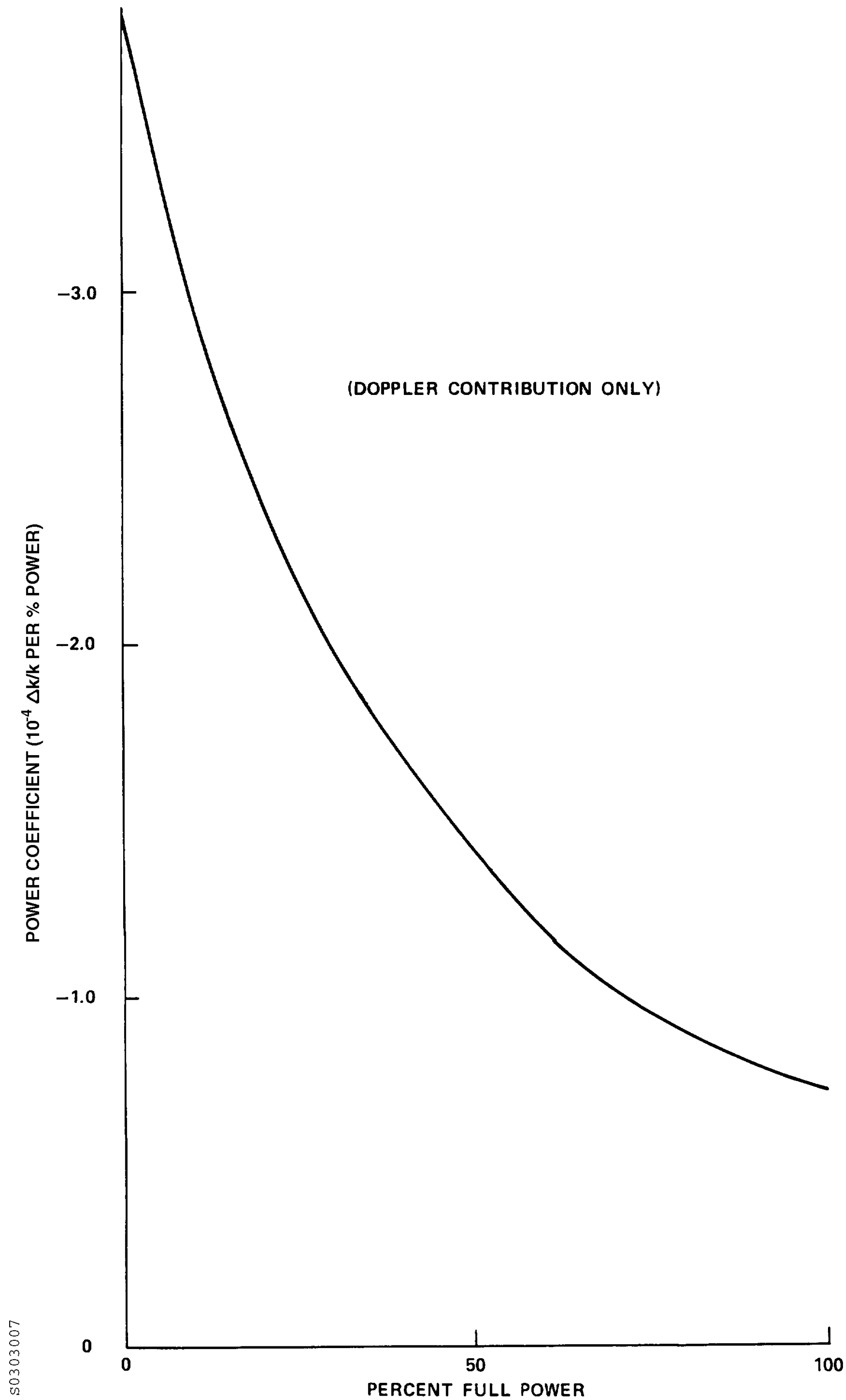


Figure 3.3-8
POWER COEFFICIENT (CLOSED GAP MODEL)

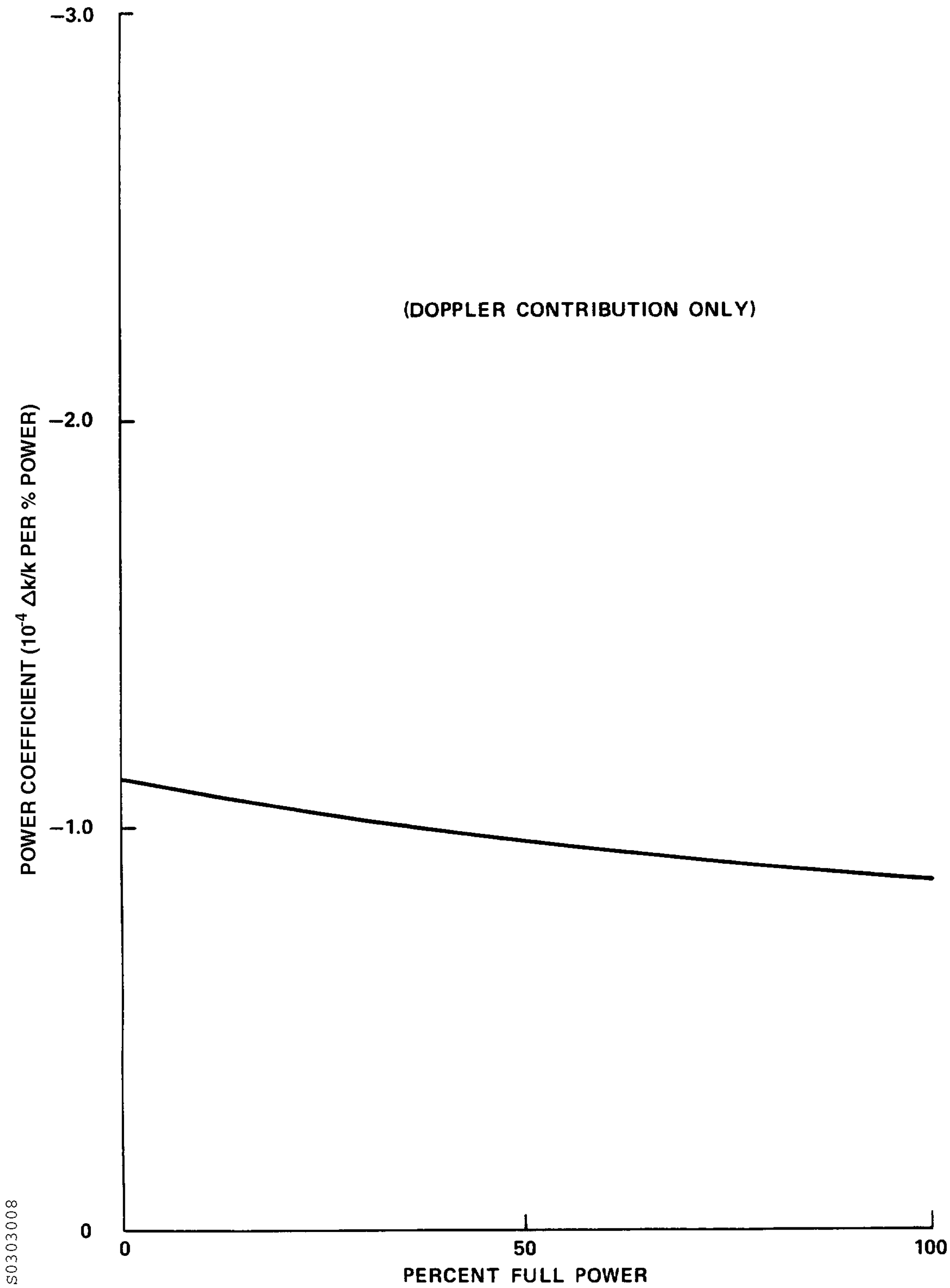
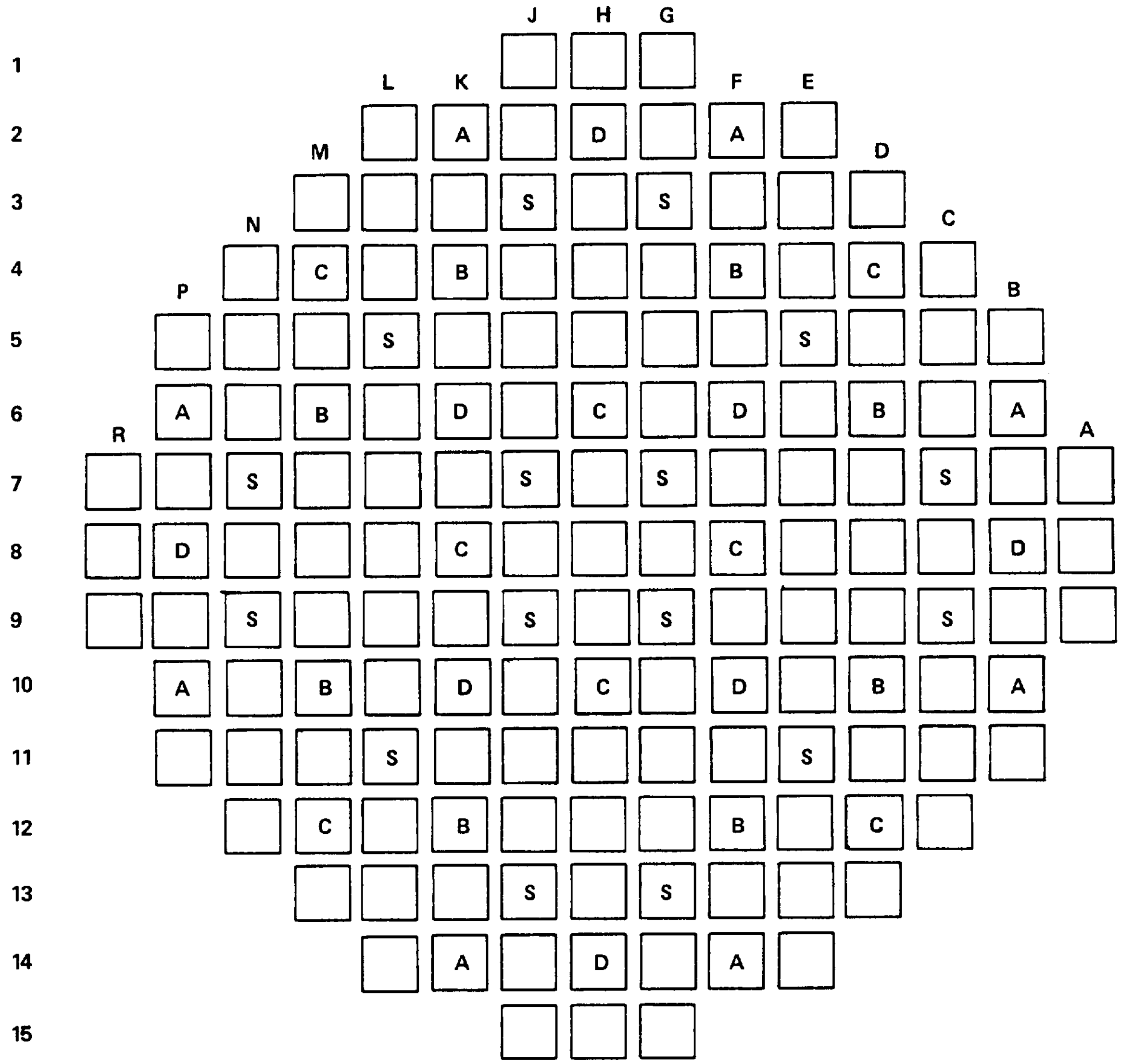


Figure 3.3-9
CONTROL ROD BANK LOCATIONS



CONTROL ROD ASSEMBLY BANKS

FUNCTION	NUMBER OF ASSEMBLIES
CONTROL BANK D	8
CONTROL BANK C	8
CONTROL BANK B	8
CONTROL BANK A	8
SHUTDOWN (S)	16
	48

S0303009

Intentionally Blank

3.4 THERMAL/HYDRAULIC DESIGN AND EVALUATION

3.4.1 Thermal/Hydraulic Characteristics of the Design

The capability of the reload core design to meet thermal-hydraulic safety limits and fuel thermal-hydraulic design criteria is evaluated as part of the reload safety evaluation process. The cycle specific reload safety evaluation addresses the thermal-hydraulic design of the reload core and confirms that the thermal-hydraulic limits are met for each fuel assembly. The thermal/hydraulic evaluation is performed to confirm Departure from Nucleate Boiling Ratio (DNBR) results for applicable UFSAR Chapter 14 accidents and transients. This is accomplished by determining if the key DNBR analysis parameters for the reload core are conservatively bounded by the values used in the applicable safety analyses of record.

The thermal-hydraulic performance of the core is projected based on assumed operating conditions and the core loading pattern which sets the type, number, and location of fresh and re-inserted fuel assemblies. The assumed operating conditions include operation within the core operating limits of the COLR.

Table 3.4-1 presents a typical set of values used in the thermal-hydraulic analyses. Thermal-hydraulic design parameter values used for the actual reload core analyses may differ slightly from the values listed in Table 3.4-1.

3.4.1.1 Fuel and Cladding Temperatures

Consistent with the thermal-hydraulic design bases, the following discussion pertains mainly to fuel pellet temperature evaluation. The thermal-hydraulic design assures that the maximum fuel temperature is below the melting point of UO_2 (melting point of 5080°F unirradiated and decreasing by 9°F per 10,000 MWD/MTU (Reference 41)). The basis for the PAD5 fuel melt limit is consistent with the descriptions in Reference 42. The temperature distribution within the fuel pellet is predominantly a function of the local power density and the UO_2 thermal conductivity. However, the computation of radial fuel temperature distributions combines crud, oxide, cladding gap and pellet conductances. The factors which influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, fuel relocation, and radial power distribution within the pellet, etc., have been combined into a semi-empirical thermal model with the model modifications for time dependent fuel densification given in References 1 and 42. This thermal model enables the determination of these factors and their net effects on temperature profiles. The temperature predictions have been compared to inpile fuel temperature measurements and/or melt radius data as part of the generic approval of the fuel performance model (References 1 and 42).

As described in References 1 and 42, fuel rod thermal evaluations (fuel centerline, average and surface temperatures) are determined throughout the fuel rod lifetime with consideration of time dependent densification. To determine the maximum fuel temperatures, various burnup rods, including the highest burnup rod, are analyzed over the rod linear power range of interest.

The principle factors which are employed in the determination of the fuel temperature are consistent with the methods described in Reference 42.

3.4.1.2 Westinghouse Experience with High-Power Fuel Rods

Westinghouse experience (through 1969) with non-pressurized fuel rods operating at high power ratings has been summarized in the Indian Point Unit 2 Preliminary Safety Analysis Report (Docket 50-247) and in the Preliminary Safeguards Report for the Saxton Reactor operating at 35 MWt (Docket 50-146). These reports present considerable statistical evidence of successful operation of 1368 high-performance Zircaloy-clad fuel rods in the Carolina-Virginia Test Reactor (CVTR) and 94,920 rods in the Shippingport Core I Blanket. After the date of these reports, a significant amount of additional information was developed relating to the integrity of free-standing Zircaloy-clad oxide fuel rods at high power ratings. In addition, a comprehensive experimental program was performed to extend the operating experience to higher power and to higher exposures. This information is summarized in Figure 3.4-2.

Figure 3.4-2 shows that 30 Saxton Plutonium Project non-pressurized fuel rods operated at a design peak power level of up to 18.5 kW/ft to a peak exposure of approximately 30,000 MWD/MTU (megawatt days per metric ton of metal (U + Pu)). No failures occurred with this fuel. In the Saxton overpower test, two selected fuel rods from the Saxton Plutonium Project assemblies were removed after peak exposure of 18,000 MWD and inserted in a subassembly for short-time irradiation at a design rating of 25 kW/ft. Results of this program indicated satisfactory performance of the fuel in every respect. The Saxton Plutonium Project was extended by irradiating approximately 250 rods to peak burnups of about 50,000 MWD/MTU at design linear power levels ranging from 9.5 to 23.6 kW/ft.

In the above tests (performed on non-pressurized rods), the strain fatigue experienced by the cladding was more severe than that expected to occur for pressurized rods, which would be placed under identical operating conditions.

Internally pressurized fuel rods have been investigated at Westinghouse. These investigations included ex-core and incore experimental programs and analytical studies. Fuel rods internally pressurized with various gases were irradiated in the Saxton reactor. Test results showed that initial pressurization was effective in substantially reducing the rate of cladding-creep onto the UO_2 fuel. The Saxton test results confirmed the results of analyses that predict fuel-cladding mechanical interaction early in life for non-pressurized fuel rods, and delayed interaction for initially pressurized fuel rods.

To verify the substantial design margin that exists with regard to excessive internal pressures in a fuel rod, several highly pressurized Zircaloy-clad fuel rods were irradiated for several months in the Saxton reactor, then removed for examination. At an internal pressure of approximately 3500 psia (as compared to the design value of 2250 psia), the fuel rods operated satisfactorily for the period of the test without any indication of failure. Two fuel rods, deliberately tested at unrealistically high internal pressures, experienced clad cracking but operated satisfactorily for the period of the test.

Westinghouse irradiated many internally pressurized fuel rods in Saxton and also at the Jose Cabrera plant in Spain. Approximately 150 fuel rods were subjected to long-term irradiation testing. These tests provided additional confirmation of the suitability of internally pressurized fuel rods. This long-term testing program was continued at Saxton until 1971 and at Jose Cabrera until 1972, and provided verification of core life performance data with the fuel rod design bases.

The initial Surry fuel was intended to operate to a peak fuel exposure of 49,000 MWD/MTU. The change in fuel characteristics as a function of exposure had been investigated in certain cases, but the exact nature and extent of such changes to the planned exposures had not been investigated in great detail. However, based upon work at lower exposures (References 2 & 3-5), such property changes were not considered of major significance and tended to saturate at relatively low exposures. The models used to predict the thermal performance of the fuel in the initial Surry cores were combined in an integrated computer program to enable consideration of the several effects arising due to irradiation. These thermal models were compared to data in the literature, with generally good correlation. The thermal performance of current fuel is similarly evaluated using an overall fuel design code that has been shown to provide good agreement with a variety of published and proprietary data (References 1 and 42).

3.4.1.3 **Pressure Drop and Hydraulic Forces**

The total pressure loss across the reactor vessel, including the inlet and outlet nozzles, and the pressure drop across the core are listed in Table 3.4-1. The design values are presented as nominal values.

3.4.2 Departure from Nucleate Boiling Technology

Departure from nucleate boiling (DNB) is predicted by analysis of hydrodynamic and heat transfer phenomena and is affected by the local and upstream conditions, including the flux distribution.

In reactor design, the heat flux associated with departure from nucleate boiling and the location of departure from nucleate boiling are both important. The magnitude of the local fuel rod temperature after departure from nucleate boiling occurs depends upon the axial location of the occurrence. The W-3 DNB correlation and its modification for the “L”-grid (References 6 & 31), which have been utilized in the analysis of 15 x 15 LOPAR assemblies (all assemblies prior to Region 12 on both units), incorporate both local and system parameters in predicting the local DNB heat flux. These correlations include the non-uniform flux effect and the upstream effect, which includes inlet enthalpy and distance. The local DNB heat flux ratio, defined as the ratio of the DNB heat flux to the local heat flux, is indicative of the margin available in the local heat flux to the onset of departure from nucleate boiling. The WRB-1 DNB correlation

(Reference 29), which is used in the analysis of 15 x 15 Surry Improved Fuel (SIF) and 15 x 15 Upgrade assemblies, is based on local fluid conditions and represents the rod bundle data with better accuracy over a wide range of variables than previous correlations (W-3 based) used in design. Validation of the WRB-1 DNB correlation applicability to the 15 x 15 Upgrade fuel assembly design is provided in Reference 37.

3.4.2.1 **W-3 Correlation**

The W-3 DNB correlation was developed to predict the DNB flux and the location of departure from nucleate boiling equally well for uniform and axially non-uniform heat flux distributions. This correlation replaced the preceding WAPD W-2 correlations (published in *Nucleonics* (Reference 7), May 1963), in order to eliminate the discontinuity of the latter at the saturation temperature, and to provide a single unambiguous criterion of the design margin.

The sources of the data used in developing this correlation were:

WAPD-188 (1958)	CU-TR-No. 1 (NW-208) (1964)
ASME Paper 62-WA-297 (1962)	CISE-R-90 (1964)
CISE-R-63 (1962)	DP-895 (1964)
ANL-6675 (1962)	AEEW-R-356 (1964)
GEAP-3766 (1962)	BAW-3238-7 (1965)
AEEW-R-213 and 309 (1963)	AE-RTL-778 (1965)
CISE-R-74 (1963)	AEEW-355 (1965)
CU-MPR-XIII (1963)	EUR-2490.e (1965)

The comparison of the measured to predicted DNB flux of this correlation is given in Figure 3.4-3. The local flux DNBR versus the probability of not reaching departure from nucleate boiling is plotted in Figure 3.4-4. This plot indicates that with a DNBR equal to the correlation DNBR limit (of 1.30), the probability of not reaching departure from nucleate boiling is 95% at a 95% confidence level.

Rod bundle data without mixing vanes agree very well with the predicted DNB flux, as shown in Figure 3.4-5. The rod bundle data with mixing vanes, shown in Figure 3.4-6, show on the average an 8% higher value of DNB heat flux than predicted by the W-3 DNB correlation.

It should be emphasized that the inlet subcooling effect of the W-3 correlation was obtained from both uniform and non-uniform data. The existence of an inlet subcooling effect has been demonstrated to be real, and hence the actual subcooling was used in the calculations. The W-3 correlation was developed from tests with flow in tubes and rectangular channels. Good agreement was obtained when the correlation was applied to test data for rod bundles.

The form of the W-3 correlation was presented by Tong in Reference 32. The W-3 predicted heat flux at DNB is calculated as follows:

$$q'' = \frac{q''_{DNB,\,EU,\,Dh}}{F}(CWF)(F'_s)$$

where:

$q''_{DNB,EU,Dh}$ = W-3 Equivalent Uniform Heat Flux with all flow cell walls heated

F = Nonuniform Heat Flux Factor (F-factor)

CWF = W-3 Cold Wall Factor

F'_s = W-3 Modified Spacing Factor

Subsequent to Reference 32, an extensive experimental program was performed to investigate the behavior of DNB due to non-uniform axial heat flux distribution, heater rod lengths, axial grid spacing, and grids with and without mixing vanes. The results of these tests are documented in References 31, 33, 34, and 35.

3.4.2.1.1 W-3 Equivalent Uniform Flux DNB Correlation

The equivalent uniform DNB flux $q'_{DNB,EU}$ is calculated from the W-3 equivalent uniform flux DNB correlation as follows (Reference 6):

$$\begin{aligned}\frac{q'_{DNB,EU}}{10^6} = {} & [(2.022 - 0.0004302p) \\ & + (0.1722 - 0.0000984p)e^{(18.177 - 0.004129p)X}] \\ & \times\left[1.037 + \frac{G}{10^6}(0.1484 - 1.596X + 0.1729X|X|)\right] \times [1.157 - 0.869X] \\ & \times [0.2664 + 0.8357e^{-3.151D_e}] \times [0.8258 + 0.000794(H_{sat} - H_{in})]\end{aligned}$$

The ranges of the parameters in the data used to develop the correlation are:

System pressure	p = 1000 to 2300 psia
Mass velocity	$G = 1.0 \times 10^6$ to 5.0×10^6 lb/hr-ft^2
Equivalent diameter	D_e = 0.2 to 0.7 in.
Quality	X = -0.25 to +0.15
Inlet enthalpy	H_{in}, no limit, Btu/lb
Length	L = 10 to 144 in.
Heated perimeter/Wetted perimeter	D_h/D_e = 0.88 to 1.00

Geometries - circular tube, rectangular channel, and rod bundles

Flux - uniform and equivalent uniform flux converted from non-uniform data by using the F-factor (See Section 3.4.2.1.2).

3.4.2.1.2 Nonuniform Heat Flux Factor (F-factor)

The F-factor relates DNB data for axially non-uniform power distributions to DNB data for axially uniform power distributions (Reference 32). Reference 33 documented the experimental program to investigate the effects on DNB due to non-uniform axial heat flux distributions. It was concluded therein that the use of the F-factor was an acceptable means of accounting for axially non-uniform power distributions.

The local non-uniform $q''_{DNB,N}$ is calculated as follows:

$$q''_{DNB,\,N} = \frac{q''_{DNB,\,EU}}{F}$$

where:

$$F = \frac{C}{q''_{local\ at\ l_{DNB}}(1 - e^{-Cl_{DNB}})}\int_0^{l_{DNB}} q''(z)e^{-C(l_{DNB} - z)}dz$$

l_{DNB} = distance from the inception of local boiling to the point of DNB

z = distance from the inception of local boiling, measured in the direction of the flow

The empirical constant, C, as presented in Reference 6, was revised in Reference 32 through the use of more recent non-uniform DNB data. However, the revised expression (showing less than 1% deviation from that of Reference 6) does not significantly influence the value of the F-factor and the DNBR. It does provide a better prediction of the location of departure from nucleate boiling.

The new expression is:

$$C = 0.15\frac{(1 - \chi_{DNB})^{4.31}}{(G/10^6)^{0.478}}in^{-1}$$

where:

G = mass velocity lb/hr-ft^2

χ_{DNB} = quality of the coolant at the location where DNB flux is calculated

In determining the F-factor, the value of q''_{local} at l_{DNB} was measured at $z = l_{DNB}$, the location where the DNB flux is calculated. For a uniform flux, F becomes unity, so that $q''_{DNB,N}$ reduces to $q''_{DNB,EU}$. The comparisons of predictions by using W-3 correlations and the non-uniform DNB data obtained by B&W (Reference 9), Lee (References 10 & 11), and Obertelli (Reference 10) are given in Figures 3.4-8 and 3.4-9. To determine the predicted location of departure from nucleate boiling, the ratio of the predicted DNB flux to the local heat flux along the length of the channel must be evaluated. The location of the minimum DNBR is considered to be the location of departure from nucleate boiling.

3.4.2.1.3 W-3 Cold Wall Factor

The W-3 equivalent uniform flux DNB correlation is used for predicting DNB in channels which are entirely, or almost entirely, surrounded by heated walls (i.e., typical cells). The W-3 Cold Water Factor (CWF) accounts for the presence of unheated surfaces due to thimble or instrument tubes (i.e., thimble cells) (Reference 32). References 34 and 35 documented the experimental program to investigate the effect on DNB due to thimble cold wall cells. It was concluded that the cold wall factor is appropriate for rod bundles with mixing vane grids.

The W-3 Cold Wall Factor from Reference 32 is:

$$CWF = 1.0 - R_u[13.76 - 1.372e^{(1.78X)} - 4.732(G/10^6)^{-0.0535} - 0.0619(P/10^3)^{0.14} - 8.509(D_h)^{0.107}]$$

where:

$R_u = 1 - (D_e/D_h)$

X = local quality, fraction

G = local mass velocity, lb/hr-ft^2

P = primary system pressure, psia

D_h = equivalent diameter based on heated perimeter, inches

3.4.2.1.4 Modified Spacer Factor, R-Grid and L-Grid Correlations

To account for mixing between subchannels due to spacer grids, Tong (Reference 32) developed a spacer grid factor for use with the W-3 equivalent uniform flux correlation. However, the use of the W-3 equivalent uniform flux correlation with this spacer factor yielded conservative predictions, particularly in rod bundles with mixing vane grid spacers. Hence, a correlation factor was developed to adapt the W-3 correlation (which was developed based on single-channel data) to rod bundles with mixing vane spacer grids. This correction factor, termed the “Modified Spacer Factor,” was developed as a multiplier on the W-3 correlation.

The Modified Spacer Factor (F'_s) was developed from rod bundle DNB test results conducted in the Westinghouse high-pressure water loop at Columbia University. These tests were conducted on non-uniform axial heat flux test sections to determine the DNB performance of a low parasitic, top-split mixing-vane grid design, referred to as the “R” grid. A description of this test program and a summary of the results are given in References 35 and 36. This Modified Spacer Factor for the “R” grid is:

$$F'_{S,R} = (1.445 - 0.0371L)(P/225.896)^{0.5}(e^{(X+0.2)^2} - 0.73) + K_S(G/10^6)(TDC/0.019)^{0.35}$$

where:

L = total heated core length, ft

P = primary system pressure, psia

X = local quality, fraction

K_S = axial grid spacing coefficient

G = local mass velocity, lb/hr-ft^2

TDC = thermal diffusion coefficient

Additional DNB testing was conducted with an “L” type grid. A description of this test program and a summary of the results are given in Reference 35. The Modified Spacer Factor for the “L” grid is simply:

$F'_{S,L} = F'_{S,R} \times 0.986$

3.4.2.2 **WRB-1 Correlation**

The details of the proprietary WRB-1 correlation are provided in Reference 29. The WRB-1 correlation was developed exclusively from Westinghouse rod mixing vane grid bundle data (over 1100 points) based on local fluid conditions. This correlation accounts directly for cold wall effects, and variations in rod heated length and grid spacing. The F-factor (Section 3.4.2.1.2) is employed for axially non-uniform heat flux profiles.

The applicable range of variables is:

Pressure	$1440 \leq P \leq 2490$ psia
Local Mass Velocity	$0.9 \leq G_{loc} / 10^6 \leq 3.7$ lb/ft^2-hr
Local Quality	$-0.2 \leq X_{loc} \leq 0.3$
Heated Length, Inlet to CHF Location	$L_h \leq 14$ ft
Grid Spacing	$13 \leq g_{sp} \leq 32$ in.
Equivalent Hydraulic Diameter	$0.37 \leq d_e \leq 0.60$ in.
Equivalent Heated Hydraulic Diameter	$0.46 \leq d_h \leq 0.59$ in.

Figure 3.4-7 shows measured critical heat flux plotted against predicted critical heat flux using the WRB-1 correlation (Reference 29).

3.4.2.3 **ABB-NV and WLOP Correlations**

The ABB-NV and WLOP correlations (Reference 38), were developed exclusively from non-mixing vane grid bundle data based on local fluid conditions. The ABB-NV and WLOP correlations are meant to be used as a replacement for the W-3 correlation. The applicable range of variables for the ABB-NV correlation is:

Pressure	$1750 \leq P \leq 2415$ psia

Local Mass Velocity	$0.8 \leq G_{loc} / 10^6 \leq 3.16$ lb/ft^2 - hr
Local Quality	$X_{loc} \leq 0.22$
Heated Length, Inlet to CHF Location	48 in* $\leq L_h \leq$ 150 in
Heated Hydraulic Diameter Ratio	$0.679 \leq d_h \leq 1.08$
Grid Distance	$7.3 \leq g_d \leq 24$ in

*For heated lengths less than 48 inches, a minimum value of 48 is used.

The applicable range of variables for the WLOP correlation is:

Pressure	$185 \leq P \leq 1800$ psia
Local Mass Velocity	$0.23 \leq G_{loc} / 10^6 \leq 3.07$ lb/ft^2 - hr
Local Quality	$X_{loc} \leq 0.75$
Heated Length, Inlet to CHF Location	48 in* $\leq L_h \leq$ 168 in
Grid Spacing Term	$27 \leq g_{st} \leq 115$
Heated Hydraulic Diameter Ratio	$0.679 \leq d_h \leq 1.00$
Matrix Heated Hydraulic Diameter	$0.4635 \leq g_d \leq 0.5334$ in

*For heated lengths less than 48 inches, a minimum value of 48 is used.

3.4.2.4 Definition of Departure from Nucleate Boiling Ratio

In predicting the local DNB flux in a non-uniform heat flux channel, the following two steps are required:

1. The uniform DNB heat flux, $q''_{DNB,\ EU}$, is computed with the W-3 or WRB-1 correlation using the specified local reactor conditions.

2. This equivalent uniform heat flux is converted into corresponding non-uniform DNB heat flux, $q''_{DNB,N}$, for the non-uniform flux distribution in the reactor. The non-uniform DNB heat flux, $q''_{DNB,N}$, is given by:

$$q''_{DNB,\ N} = \frac{q''_{DNB,\ EU}}{F}$$

The DNB heat flux ratio is defined as:

$$DNBR = \frac{q''_{DNB,\ N}}{q''_{loc}}$$

where q''_{loc} is the actual local heat flux.

To calculate the minimum DNBR of a reactor coolant flow channel, the values of $(q''_{DNB,N})/(q''_{loc})$ along the channel are evaluated and the minimum value is selected as the minimum DNBR in that channel.

The W-3 and WRB-1 correlations depend on both local conditions and inlet enthalpies of the actual system fluid. Thus, the minimum DNBRs calculated with the correlations provide a measure of the margin on heat flux when compared to the DNBR design limits.

3.4.3 Thermal/Hydraulic Evaluation

3.4.3.1 Core Analysis

The basic objective of core thermal-hydraulic analysis is to verify that safety limits established by departure from nucleate boiling (DNB) concerns are met. Thermal-hydraulic design parameters are presented in Table 3.4-1. DNB, which could occur on the heating surface of the fuel rod, is characterized by sudden decrease in the heat transfer coefficient with corresponding increase in the surface temperature. DNB is of concern in reactor design because of the possibility of fuel cladding rod failure resulting from the increased temperature.

In order to preclude potential DNB related fuel damage, a design basis is established and is expressed in terms of a minimum departure from nucleate boiling ratio (MDNBR). DNBR is the ratio of the predicted heat flux at which DNB occurs (i.e., the critical heat flux, CHF) and the local heat flux of the fuel rod. By imposing a design DNBR limit, adequate heat transfer between the fuel cladding and the reactor coolant is assured. DNBRs greater than the design limit indicate the existence of thermal margin within the nuclear core. Thus, the purpose of core thermal-hydraulic analysis, or DNB analysis, is the accurate calculation of DNBRs in order to assess and quantify core thermal margin.

In performing DNB analysis, a subchannel approach is commonly used wherein a section of the core is modeled as an array of adjoining subchannels. Each subchannel is defined as the flow channel formed by four fuel rods, or by three fuel rods and a guide thimble tube. When the fuel rods are given design radial and axial power distributions, the array represents the region of maximum design power generation. Within this array, the hottest subchannel (hot channel) is identified with the fuel rod which has the highest integrated power (hot fuel rod). Engineering uncertainties are applied to the hot channel and the hot fuel rod in order to conservatively account for manufacturing tolerances. A detailed thermal analysis of the core is then performed to determine the flows and enthalpies at each axial position within the hot channel.

When performing the thermal analysis, it is necessary to consider the effect that the surrounding core region has on the subchannel flows. The problem is basically one of integrating the relatively small subchannel geometry into a larger geometry which is representative of the entire core. Traditionally, the problem has been solved by using a multistage method involving at least two analyses. A core analysis is first performed to provide crossflow boundary conditions which are used in the subsequent subchannel analysis. In the core analysis, each fuel assembly is modeled as a single, lumped flow channel. In the subchannel analysis, the hot assembly is modeled separately as an array of subchannels. Hot assembly crossflows determined in the first analysis are used as boundary conditions in the second analysis in order to simulate the effects of the core on the subchannel flows. The original Surry thermal-hydraulics design code, THINC (Reference 8), is a multistage code.

An alternate, more direct approach for performing the thermal analysis is a single stage method. Using this method, a single analysis is performed in which an array of subchannels representing the hot assembly is combined with an array of lumped channels which represent the remaining assemblies within a core segment. Using this single geometry, boundary conditions are not required since the effect of the core is inherently included when computing the subchannel flows. Although single stage analyses have been performed previously, the thermal-hydraulic codes then in existence were capable of handling only a limited number of channels. This necessitated coarse simulations of the core consisting of only a few subchannels together with very large lumped channels representing many assemblies. However, the development of the COBRA IIIC/MIT computer code (Reference 24) has provided the capability to analyze geometries consisting of up to 200 channels. Thus, it is now possible to perform single stage thermal analyses using the same radial nodalization as used in the traditional multistage analyses.

This concept has been applied by Virginia Electric and Power Company (Vepco) in the development of a core thermal-hydraulics analysis capability. This capability is based upon a single stage analysis which incorporates the geometries and methodologies used in multistage analyses. The accuracy of this approach has been verified through comparisons with analyses which were used in the design and licensing of the Surry Nuclear Power Station.

The COBRA IIIC/MIT computer code calculates the flow and enthalpy within interconnected flow channels by solving finite difference equations of continuity, energy, and momentum. The mathematical model is applicable to both steady state and transient conditions, and the model considers both turbulent mixing and diversion crossflow. In formulating the mathematical model, one-dimensional, two-phase, separated slip-flow was assumed to exist during boiling. The two-phase flow structure was assumed to be fine enough to allow specification of void fraction as a function of enthalpy, flow rate, heat flux, pressure, position and time. Sonic velocity propagation effects were not included. Within a channel, the diversion crossflow velocity was assumed to be small compared to the axial velocity. This assumption allowed the use of a simplified equation for the conservation of transverse momentum.

The equations are solved as a boundary value problem by using a semi-explicit finite difference scheme. The boundary conditions for the problem are in the inlet enthalpy, inlet mass velocity and exit pressure. The boundary value solution is obtained by assuming a uniform exit pressure distribution. (The equations do not require actual pressures since only pressure differences are used.) When performing a computation, the code iterates over the length of the core until convergence of the flow solution is obtained. Convergence is achieved when the change in any channel flow is less than a user specified fraction of the flow from the previous iteration.

The same finite difference equations are used for both steady state and transient computations. For steady state calculations, the time step, Δt, is set equal to an arbitrarily large value thereby negating the time dependent terms. For transient calculations, the time step is set equal to a user specified value. When performing a transient calculation, a steady state calculation is first performed to obtain initial conditions. Time dependent forcing functions consisting of inlet temperature, inlet flow, system pressure, and core average heat flux are used to establish boundary conditions at succeeding times. The calculation iterates over the first time step until the flow solution converges. The converged solution is then used as the initial conditions for the new time, and the procedure continues for all of the subsequent time steps.

Although the equations of continuity, energy and momentum form the basic structure of the mathematical model, their solution is still dependent upon the use of empirical correlations. Of major importance are the correlations used in calculating the pressure gradient and those used in calculating turbulent mixing. Once the flow solution is obtained, additional correlations are used in calculating the DNBR distribution. The COBRA IIIC/MIT computer code allows user specification of the appropriate correlations.

VIPRE-D (Reference 38) is the Dominion version of the computer code VIPRE (Versatile Internals and Components Program for Reactors - EPRI), developed for EPRI (Electric Power Research Institute) by Battelle Pacific Northwest Laboratories in order to perform detailed thermal-hydraulic, subchannel analyses to predict CHF and DNBR of reactor cores. VIPRE-01 has been approved by the U.S. Nuclear Regulatory Commission (USNRC). VIPRE-D, which is based upon VIPRE-01, was developed by Dominion to fit the specific needs of Dominion's nuclear plants and fuel products by adding vendor specific CHF correlations and customizing its input and output. Dominion, however, has not made any modifications to the NRC-approved constitutive models and algorithms in VIPRE-01.

The NRC has approved the use of the Vepco version of the COBRA-IIIC/MIT code (Reference 24) and the VIPRE-D code (Reference 38) as alternative approaches for performing reactor core thermal-hydraulic analysis.

3.4.3.2 **Application of DNB Correlations in Design**

The WRB-1 and W-3 CHF correlations are used for the calculation of DNBRs in Westinghouse 15 x 15 SIF fuel assemblies. The WRB-1 CHF correlation is applicable to the operating conditions for which the Statistical DNBR Evaluation Methodology applies. The W-3 correlation is only used below the first mixing grid or when the operating conditions are outside of the range of validity of the WRB-1 CHF correlation, such as the main steam-line break evaluation, where there are reduced temperature and pressure. The W-3 CHF correlation is always used deterministically. COBRA IIIC/MIT is used to determine the local conditions for the DNB evaluation of the 15 x15 SIF. Table 3.2-1 list the DNBR limits for application of WRB-1 and W-3 correlations with COBRA IIIC/MIT.

The WRB-1, W-3, ABB-NV, and WLOP CHF correlations are used for the calculation of DNBRs in Westinghouse 15 x15 Upgrade fuel assemblies. The WRB-1 CHF correlation is applicable to the operating conditions for which the Statistical DNBR Evaluation Methodology applies. The W-3 or ABB-NV correlation is used below the first mixing grid. The W-3 or WLOP correlation is used when the operating conditions are outside of the range of validity of the WRB-1 CHF correlation, such as the main steam-line break evaluation, where there are reduced temperature and pressure. The W-3, ABB-NV and WLOP CHF correlations are always used deterministically. VIPRE-D is used to determine the local conditions for the DNB evaluation of the Westinghouse 15 15 Upgrade fuel. Table 3.2-1 list the DNBR limits for application of WRB-1, W-3, ABB-NV, and WLOP correlations with VIPRE-D.

During steady-state operation at the nominal design conditions, the values of the DNBR are determined. Under adverse operating conditions, particularly overpower transients, more limiting conditions develop than those existing during steady-state operation.

For transients which are analyzed with a deterministic treatment of key DNBR analysis uncertainties, initial conditions are obtained by combining maximum steady-state errors with nominal values. The following steady-state errors are considered:

1. Core Power +2 percent calorimetric error allowance
2. Average Reactor Coolant System (RCS) temperature +4°F controller deadband and measurement error allowance
3. Pressurizer pressure ±30 psi steady-state fluctuations and measurement error allowance
4. Reactor flow Thermal design flow

Initial values for core power, average reactor coolant system temperature, and pressurizer pressure are selected to minimize the initial DNBR unless otherwise stated in the sections describing specific accidents (See Chapter 14).

The ranges of permissible initial reactor operating conditions of core flow rate, system temperatures and system pressure are stated in the Technical Specifications for Surry Power Station.

For transients which are analyzed under the Virginia Power *Statistical DNBR Evaluation Methodology* (Reference 30), nominal values are used for the initial conditions in the transient analysis. The use of the Statistical DNBR Evaluation Methodology does not require that the uncertainties be applied in the initial conditions since these uncertainties are statistically incorporated in the statistical design limit (see Section 3.2.3.3). The Statistical DNBR Evaluation Methodology is employed on a transient specific basis (See Section 3.2.3.3) as indicated in the transient analysis summaries in Chapter 14.

3.4.3.3 **Effects of Departure From Nucleate Boiling on Neighboring Rods**

DNB propagation would occur when a rod in DNB which is above system pressure is assumed to balloon at the location of DNB and contact an adjacent rod which would then experience DNB due to local flow blockage. The design basis precludes extensive DNB propagation and associated fuel failures. The design basis for this criterion is that no increase in fuel failures due to DNB propagation will occur in cores that have fuel rods operating with rod internal pressure in excess of system pressure. The design limit for Condition II events is that DNB propagation is not extensive, that is, the process is shown to be self-limiting and the number of rods in DNB and above system pressure is less than 1 rod. For Condition III/IV events, it is shown that the best estimate total fraction of rods in the core that are in DNB, including the effects of DNB propagation, for a specific event is less than the calculated fraction of rods violating the DNBR for that event.

3.4.3.3.1 Departure From Nucleate Boiling With Physical Burnout

Westinghouse (Reference 12) has conducted DNB tests in a 25-rod bundle where physical burnout occurred with one rod. After this occurrence, the 25-rod test section was used for several days to obtain more DNB data from the other rods in the bundle. The burnout and deformation of the rod did not affect the performance of neighboring rods in the test section during the burnout, or the validity of the subsequent DNB data points as predicted by the W-3 correlation. No occurrences of flow instability or other abnormal operation were observed.

3.4.3.3.2 Departure From Nucleate Boiling With Return to Nucleate Boiling

Additional DNB tests were conducted by Westinghouse (Reference 13) in 19-rod and 21-rod bundles. In these tests, departure from nucleate boiling without physical burnout was experienced more than once on single rods in the bundles for short periods of time. Each time, a reduction in power of approximately 10% was sufficient to reestablish nucleate boiling on the surface of the rod. During these and subsequent tests, no adverse effects were observed on this rod or any other rod in the bundle as a consequence of operating in departure from nucleate boiling.

3.4.3.4 **Hydrodynamic and Flow Power Coupled Instability**

Boiling flows may be susceptible to thermal-hydraulic instabilities (Reference 14). These instabilities are undesirable in reactors because they may cause a change in thermal-hydraulic conditions that may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition or to undesired forced vibrations of core components. Therefore; a thermal-hydraulic design criterion was developed which states that modes of operation under Condition I and II events will not lead to thermal-hydrodynamic instabilities.

Two specific types of flow instabilities are considered for Westinghouse PWR operation. These are the Ledinegg or flow excursion type of static instability and the density wave type of dynamic instability.

A Ledinegg instability involves a sudden change in flow rate from one steady state to another. This instability occurs when the slope of the Reactor Coolant System pressure drop-flow rate curve ($d\Delta P/dG$ internal) becomes algebraically smaller than the loop supply (pump head) pressure drop-flow rate curve ($d\Delta P/dG$ external). The criterion for stability is $d\Delta P/dG$ internal > $d\Delta P/dG$ external. The Westinghouse pump head curve has a negative slope ($d\Delta P/dG$ external < 0), whereas the Reactor Coolant System pressure drop-flow curve has a positive slope

($d\Delta P/dG$ internal > 0) over the Condition I and Condition II operational ranges. Thus, the Ledinegg instability will not occur.

The mechanism of density wave oscillations in a heated channel has been described by Lahey and Moody (Reference 15). Briefly, an inlet flow fluctuation produces an enthalpy perturbation. This perturbs the length and the pressure drop of the single-phase region and causes quality or void perturbations in the two-phase regions which travel up the channel with the flow. The quality and length perturbations in the two-phase region create two-phase pressure drop perturbations. However, because the total pressure drop across the core is maintained by the characteristics of the fluid system external to the core, the two-phase pressure drop perturbation feeds back to the single phase region. These resulting perturbations can be either attenuated or self-sustained. A simple method has been developed by Ishii (Reference 16) for parallel closed channel systems to evaluate whether a given condition is stable with respect to the density wave type of dynamic instability. This method has been used to assess the stability of typical Westinghouse reactor designs under Condition I and II operation. The results indicate that a large margin to density wave instability exists; for example, increases on the order 150 to 200 percent of rated reactor power would be required for the predicted inception of this type of instability.

The application of Ishii's method (Reference 16) to Westinghouse reactor designs is conservative because of the parallel open channel feature of Westinghouse PWR cores. For such cores, there is little resistance to lateral flow leaving the flow channels of high power density. There is also energy transfer from high power density channels to lower power density channels. This coupling with cooler channels causes an open channel configuration to be more stable than the above closed channel configuration under the same boundary conditions. Flow stability tests (References 17 and 39) have been conducted in which the closed channel systems were shown to be less stable than when the same channels were cross-connected at several locations. The cross-connections were such that the resistance to channel-to-channel crossflow and enthalpy perturbations would be greater than that which would exist in a PWR core which has a relatively low resistance to crossflow.

Flow instabilities, which have been observed, have occurred almost exclusively in closed channel systems operating at low pressures relative to the Westinghouse PWR operating pressures. Kao, Morgan and Parker (Reference 18) analyzed parallel closed channel stability experiments simulating a reactor core flow. These experiments were conducted at pressures up to 2200 psia. The results showed that for flow and power levels typical of power reactor conditions, no flow oscillations could be induced above 1200 psia. Additional evidence that flow instabilities do not adversely affect thermal margin is provided by the data from the rod bundle DNB tests. Many Westinghouse rod bundles have been tested over wide ranges of operating conditions with no evidence of premature DNB or of inconsistent data which might indicate flow instabilities in the rod bundle.

In summary, it is concluded that thermal-hydrodynamic instabilities will not occur under Condition I and II modes of operation for Westinghouse PWR reactor designs. A large power margin exists to predicted inception of such instabilities. Analysis has been performed which shows that minor plant-to-plant differences in Westinghouse reactor designs - such as fuel assembly arrays, core power to flow ratios, and fuel assembly length - will not result in gross deterioration of the above power margins.

3.4.3.5 **Fuel Rod Bow**

Rod bowing in excess of that originally expected was observed in Westinghouse 15 x 15 low parasitic (LOPAR) fuel assemblies. Based on these observations, Westinghouse developed an empirical model to conservatively predict rod bow. Westinghouse used the model to analyze the impact of increased rod bow on the DNBR. The conclusion was that the impact of rod bow could be accommodated by existing design margins, and reactor safety was not affected. This information was formally submitted for NRC generic review in January 1976 (Reference 19).

Several inherent design margins were generically associated with Westinghouse DNBR analyses of LOPAR fuel, and were used to accommodate the increased rod bowing as discussed in Reference 19. The LOPAR conservatisms include:

1. Axial heat flux spikes.
2. Better data correlation resulting in a 95 × 95 confidence level DNBR limit of 1.24 versus the original limit of 1.30.
3. Pitch reduction modeling.
4. Assumed thermal diffusion coefficient (TDC) values.

Further testing by Westinghouse of selected rods (for a thimble cell) bowed into contact indicated that the inherent design margins identified above could not offset the DNBR reduction being seen. As a result, penalties on $F\Delta H$ were required by the NRC (Reference 20).

Based on more recent test data obtained and evaluated by Westinghouse, the appropriate reductions in $F\Delta H$ (or DNBR) resulting from fuel rod bow during irradiation were determined to be significantly less than those accommodated in the Technical Specifications as a result of Reference 20. The more recent tests were concerned with the determination of the DNBR reduction due to rod bow when selected rods (forming a thimble cell) were bowed to 85% channel closure. As documented in References 19, 20, and 21, the 85% channel closure would not be exceeded, on a 95 × 95 basis, for a region of fuel up to 33,000 MWD/MTU (the nominal region average discharge burnup). The DNBR reduction associated with the 85% channel closure tests was found to be 11.7% for 15 x 15 LOPAR fuel (Reference 21). The 11.7% DNBR reduction was more than completely offset by existing thermal margins in the core design. The inherent thermal margins previously delineated for the 15 x 15 LOPAR fuel provided thermal margins in excess of 18%. Therefore, the appropriate reduction in $F\Delta H$ due to rod bow was determined to be zero at all operating conditions for the Surry Power Stations (Reference 22). The NRC subsequently approved this position (Reference 23).

More recently, Westinghouse employed a revised rod bow evaluation methodology (Reference 25) to significantly reduce the required rod bow penalty. NRC approval (Reference 26) of Reference 25 permitted Virginia Electric and Power Company to apply the reduced penalty in DNBR evaluation, thus freeing most of the available retained DNBR margin for other uses. No Technical Specification changes were required, but the NRC was notified (Reference 27) in an information letter of Virginia Power's use of the reduced penalty. The NRC, subsequently, approved a further reduction in the maximum applicable burnup from 33,000 to 24,000 MWD/MTU (Reference 28).

The rod bow behavior of the 15 x 15 SIF assemblies and the mixing vane grid spans of the 15 x 15 Upgrade assemblies is predicted to be within the bounds of existing 15 x 15 LOPAR assembly rod bow data (Reference 36). The most probable causes of significant rod bow are rod-grid and pellet-clad interaction forces and wall thickness variation (WTV). The SIF assembly will have reduced grid forces (due to the greater irradiation-induced relaxation of the zirconium alloy grids) and the same fuel tube thickness-to-diameter ration (t/d) as the LOPAR assembly, which should tend to decrease SIF rod bow compared to LOPAR fuel. For a given burn-up, the magnitude of rod bow gap closure for the SIF assembly is conservatively taken to be the same as that applied to the 15 x 15 LOPAR fuel assembly.

In the upper spans of the 15 x 15 Upgrade fuel assemblies, additional restraint is provided with the intermediate flow mixer grids (IFMs) such that the grid-to-grid spacing in those spans with IFMs is approximately 13 inches compared to the approximately 26 inches in the other spans. Using the NRC approved scaling factor (References 25 and 28), results in predicted channel closure in the limiting 13 inch spans of less than 50 percent closure. Therefore, no rod bow penalty is required in the 13 inch spans in safety analysis.

The available retained DNBR margin (see Section 3.2.3.3) is used to accommodate DNB penalties due to fuel rod bowing.

3.4.3.6 **Transition Core DNB Methodology**

The Westinghouse transition core DNB methodology is given in Reference 40. Using this methodology, transition cores are analyzed as if the entire core consisted of one assembly type. The resultant DNBRs are then reduced by the appropriate transition core penalty.

The 15 x 15 SIF fuel assembly has a higher mixing vane grid loss coefficient relative to the Upgrade mixing vane grid loss coefficient. The 15 x 15 Upgrade fuel assembly has Integral Flow Mixer (IFM) grids located in spans between mixing vane grids, where no grid exists in the 15 x 15 SIF assembly. The higher loss coefficients and the additional grids introduce localized flow redistribution between the fuel assemblies at various axial zones in a transition core. Because the localized flow redistribution results in reduced flows to both fuel types at various axial locations, transition core penalties are applied to both fuel types. The transition core DNBR penalties are functions of the number of each fuel assembly type in the core, Reference 40. Sufficient DNBR margin (see Section 3.2.3.3) is maintained in the safety analysis to offset the transition core penalties.

3.4 REFERENCES

1. R. A. Weiner et al., *Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations,* WCAP-10851-P-A (Proprietary), August 1988.
2. J. A. Christensen, R. J. Allio, and A. Biancheria, *Melting Point of Irradiated Uranium Dioxide*, WCAP-6065, February 1965.
3. D. J. Clough and J. B. Sayers, *The Measurement of the Thermal Conductivity of UO_2 Under Irradiation in the Temperature Range 150°-1600°C*, Report AERE-R4690, U.K.A.E.A. Research Group, Harwell G. B., December 1964.
4. I. Devold, *A Study of the Temperature Distribution in UO_2 Reactor Fuel Elements*, Report AE-318, Aktiebolaget Atomenergi, Stockholm, Sweden, 1968.
5. J. P. Stora, D. de B. Desirgorzes, R. Deimas, P. Daschamps, B. Travard, and C. Rionigot, *Conductilite Thermique de l'Oxyde d'Uranium Fritte dans les Conditions d'Utilisation en Pile*, CEA-R-2586, 1964 (also EURAEC 1095).
6. L. S. Tong, "Prediction of Departure from Nucleate Boiling for an Axially Non-Uniform Heat Flux Distribution," *Journal of Nuclear Energy*, Vol. 21, pp. 241-248, 1967.
7. L. S. Tong, H. B. Currin, and A. G. Thorp II, "New Correlations Predict DNB Conditions," *Nucleonics*, May 1963. Also WCAP-1997, 1963.
8. H. Chelemer, J. Weisman, and L. S. Tong, *Subchannel Thermal Analysis of Rod Bundle Cores*, WCAP-7015, January 1967.
9. D. F. Judd et al., *Non-Uniform Heat Generation Experimental Program*, BAW-3238-7, 1965.
10. D. H. Lee and J. D. Obertelli, *An Experimental Investigation of Forced Convection Burnout in High Pressure Water, Part II, Preliminary Results for Round Tubes with Non-Uniform Axial Heat Flux Distribution*, AEEW-R-309, Winfrith, England, 1963.
11. D. H. Lee, *An Experimental Investigation of Forced Convection Burnout in High Pressure Water, Part IV, Large Diameter Tubes at About 1600 psi,* AEEW-R-479, Winfrith, England, 1966.
12. J. Weisman, A. H. Wenzel, L. S. Tong, D. Fitzsimmons, W. Thorne, and J. Batch, "Experimental Determination of the Departure from Nucleate Boiling in Large Rod Bundles at High Pressure," AIChE, Preprint 29, Ninth National Heat Transfer Conference, Seattle, Washington, 1967.
13. L. S. Tong, H. Chelemer, J. E. Casterline, and B. Matzner, "Critical Heat Flux (DNB) in Square and Triangular Array Rod Bundles," *JSME Semi-International Symposium, Paper #256*, Tokyo, Japan, 1967.

14. Boure, J.A., Bergles, A.E., and Tong, L.S., *Review of Two-Phase Flow Instability*, Nuclear Engineering Design 25 (1973) p. 165-1 92.

15. Lahey, R.T. and Moody, F.J., *The Thermal Hydraulics of a Boiling Water Reactor*, American Nuclear Society, 1977.

16. Saha, P., Ishii, M. and Zuber, N., *An Experimental Investigation of the Thermally Induced Flow Oscillations in Two-Phase Systems*, Journal of Heat Transfer, November 1976, pp. 616-622.

17. Kakac, S., Veziroglu, T.N., Akyuzlu, K., Berkol, O., *Sustained and Transient Boiling Flow Instabilities in a Cross-Connected Four-Parallel-Channel Upflow System*, Proceedings of 5th International Heat Transfer Conference, Tokyo, September 3-7, 1974.

18. Kao, H.S., Morgan, C.D., and Parker, W.B., *Prediction of Flow Oscillation in Reactor Core Channel*, Transactions of the American Nuclear Society, Vol. 16, 1973, pp. 212-213.

19. Westinghouse Electric Corporation, *Fuel Rod Bowing*, WCAP-8692, December 1975.

20. U.S. Nuclear Regulatory Commission, *Interim Safety Evaluation Report on Effects of Fuel Rod Bowing on Thermal Margin Calculations for Light Water Reactors (Revision 1)*, February 16, 1977.

21. Westinghouse Electric Corporation, letter NS-CE-1580 to NRC, October 24, 1977.

22. Virginia Electric Power Company, letter from C. M. Stallings (Vepco) to E. G. Case (NRC), Serial No. 095, February 21, 1978.

23. U.S. Nuclear Regulatory Commission, letter from A. Schwencer (NRC) to W. L. Proffitt (Vepco), July 27, 1979.

24. F. W. Sliz & K. L. Basehore, *Vepco Reactor Core Thermal-Hydraulic Analysis Using the COBRA-IIIC/MIT Computer Code*, VEP-FRD-33-A, October 1983.

25. Skarita, J., et al., *Fuel Rod Bow Evaluation*, WCAP-8691 Rev. 1 (July 1979)

26. Letter from C. O. Thomas (NRC) to E. P. Rahe, Jr. (W), *Acceptance for Referencing of Licensing Topical Report WCAP-8691 (P) /WCAP-8692 (NP)*, dated December 29, 1982.

27. Letter from W. L. Stewart (Virginia Electric and Power Company) to H. R. Denton (NRC), *Virginia Power Reduction in Rod Bow DNBP Penalty for Surry Power Station Unit Nos. 1 & 2*, Serial No. 85-064, dated March 21, 1985.

28. Letter from C. Berlinger (NRC) to E. P. Rahe, Jr. (Westinghouse), *Request for Reduction in Fuel Assembly Burnup Limit for Calculation of Maximum Rod Bow Penalty*, June 18, 1986.

29. Motley, F. E., et al., *New Westinghouse Correlation WRB-1 for Predicting Critical Heat Flux in Rod Bundles with Mixing Vane Grids*, WCAP-8763-NP-A (July 1984).

30. R. C. Anderson, *Statistical DNBR Evaluation Methodology*, VEP-NE-2-A, June 1987.

31. F. F. Cadek and F. E. Motley, *Application of Modified Spacer Factor to L Grid Typical & Cold Wall Cell DNB,* WCAP-7988-P-A (Proprietary) and WCAP-8030-A (Non-proprietary), January 1975.

32. L. S. Tong, *Boiling Crisis and Critical Heat Flux,* AEC Critical Review Series, TID-25887, 1972.

33. Westinghouse Electric Corporation reports WCAP-7411, Revision 1-P-A (Proprietary) and WCAP-7813-A (Non-proprietary) entitled *Rod Bundle Axial Non-Uniform Heat Flux DNB Tests and Data,* January 1975.

34. Westinghouse Electric Corporation reports WCAP-7695, Add. 1-P-A (Proprietary) and WCAP-7958, Add. 1-A (Non-proprietary) entitled *DNB Test Results for R Grid Thimble Cold Wall Cells,* January 1975.

35. Westinghouse Electric Corporation reports WCAP-7695-P-A (Proprietary) and WCAP-7958-A (Non-proprietary) entitled *DNB Test Results for New Mixing Vane Grids (R),* January 1975.

36. W. L. Stewart (Virginia Power) to U. S. Nuclear Regulatory Commission, *Proposed Technical Specifications Change Surry Improved Fuel Assembly,* Serial No. 87-188, May 26, 1987.

37. Letter from J. A. Gresham (Westinghouse) to J. S. Wermiel (NRC), *Fuel Criterion Evaluation Process (FCEP) Notification of the 15 x 15 Upgrade Design*, (Proprietary/Non-Proprietary), LTR-NRC-04-8, February 6, 2004.

38. B. L. Mount, *Reactor Core Thermal-Hydraulics Using the VIPRE-D Computer Code*, DOM-NAF-2-P-A, Rev. 0.3, September 2014.

39. Taleyarkhan, R., Podowski, M., Lahey, Jr., R.T., *An Analysis of Density — Wave Oscillations in Ventilated Channels*, NUREG/CR-2972, March 1983.

40. Schueren, P. and McAtee, K. R., *Extension of Methodology for Calculating Transition Core DNBR Penalties*, WCAP-11837-P-A, January 1990.

41. Letter from J. Klos (NRC) to D. G. Stoddard (Dominion Energy), *Surry Power Station, Units 1 and 2 - Issuance of Amendment Nos. 305 and 305, Re: Revised Reactor Core Safety Limit to Reflect Topical Report WCAP-177642-P-A,* Revision 1 (EPID L-2020-LLA-0219), October 26, 2021.

42. Linsuain, 0., et al., *Westinghouse Performance Analysis and Design Model (PAD5)*, WCAP-17642-P-A, Revision 1, November 2017.

43. WCAP-18561-P, Rev. 2 - *Reactor Internals Upflow Conversion Program Engineering Report Surry Unit 1 and* Unit 2.

Table 3.4-1
THERMAL/HYDRAULIC DESIGN PARAMETERS

	Current Operation
Total core heat output	2587 MWt
Total core heat output	8829×10^6 Btu/hr
Heat generated in fuel	97.4%
Maximum thermal overpower	118%
Nominal system pressure	2250 psia
Coolant flow	
Total flow rate	265,500 gpm
Total flow rate at inlet	101.2×10^6 lb/hr
Average velocity along fuel rods	13.3 ft/sec
Average mass flux	2.27×10^6 lb/hr-ft^2
Core bypass flow	6% (Unit 2), 6.7% (Unit 1) (3)
Coolant temperature	
Nominal inlet, °F	539.9
Average rise in vessel	66.2
Average rise in core	70.0
Average in core	576.6
Average in vessel	573.0
Average core discharge	609.9
Average vessel discharge	606.1
Heat transfer	
Active heat transfer surface area	42,460 ft^2
Average heat flux	202,500 Btu/hr-ft^2
Average linear power	6.56 kW/ft
Peak linear power for normal operation	16.4 kW/ft (1)
Pressure drop	
Across core	22.8 psi (2)
Across vessel, including nozzles	43.4 psi (2)
DNBR Correlation	WRB -1 (SIF, Upgrade)

1. Based on FQ of 2.50.
2. These are nominal pressure drops for 15 x 15 Upgrade Fuel and are based on a best estimate flow of 294,900 gpm. The pressure drops for 15 x 15 SIF are 23.8 psi (core) and 44.4 psi (vessel).
3. Unit 1 core bypass flow from Reference 43.

Figure 3.4-1
DELETED)

Figure 3.4-2
HIGH-POWER FUEL ROD EXPERIMENTAL PROGRAM

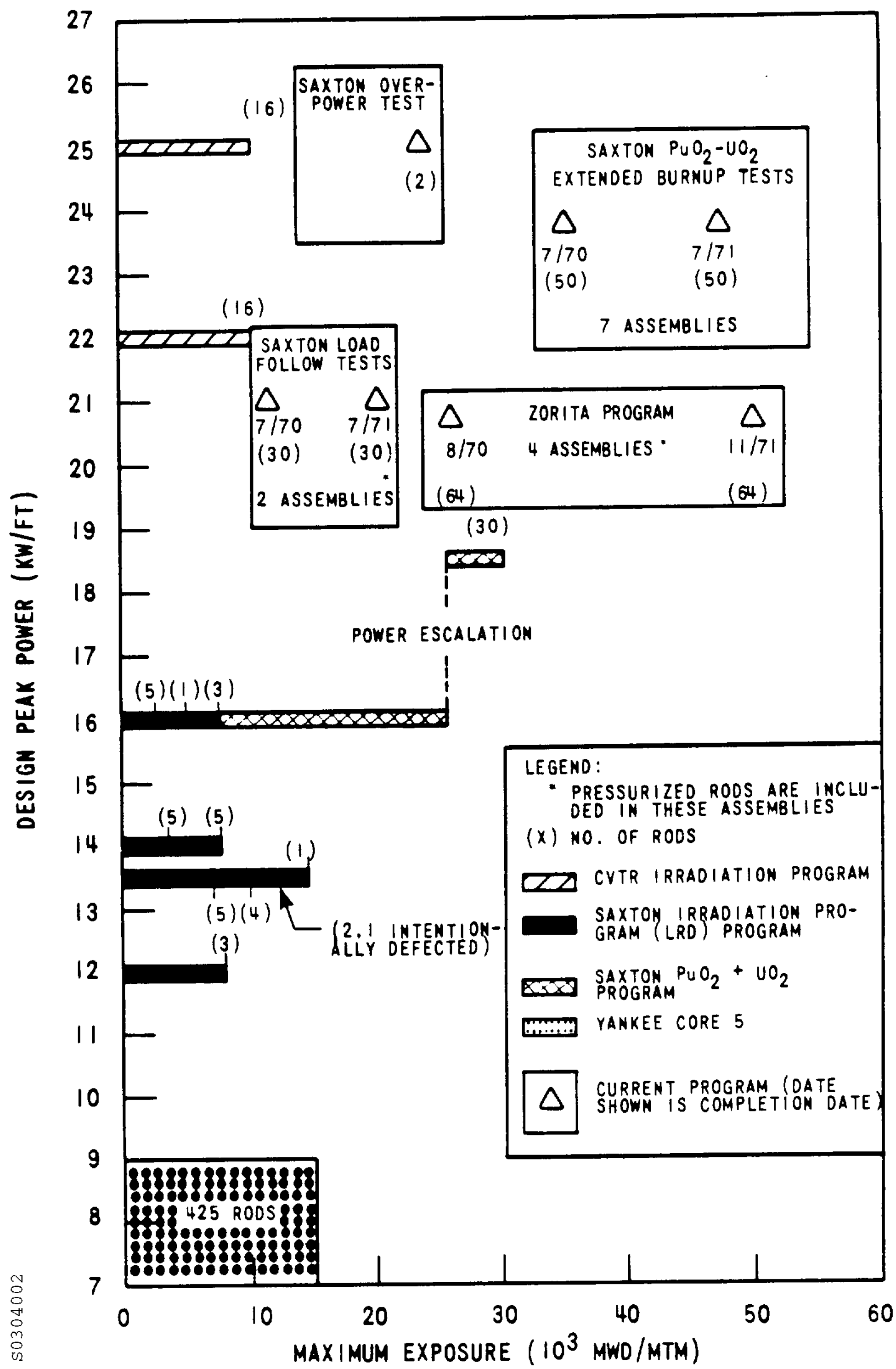


Figure 3.4-3
COMPARISON OF W-3 PREDICTION AND UNIFORM FLUX DATA

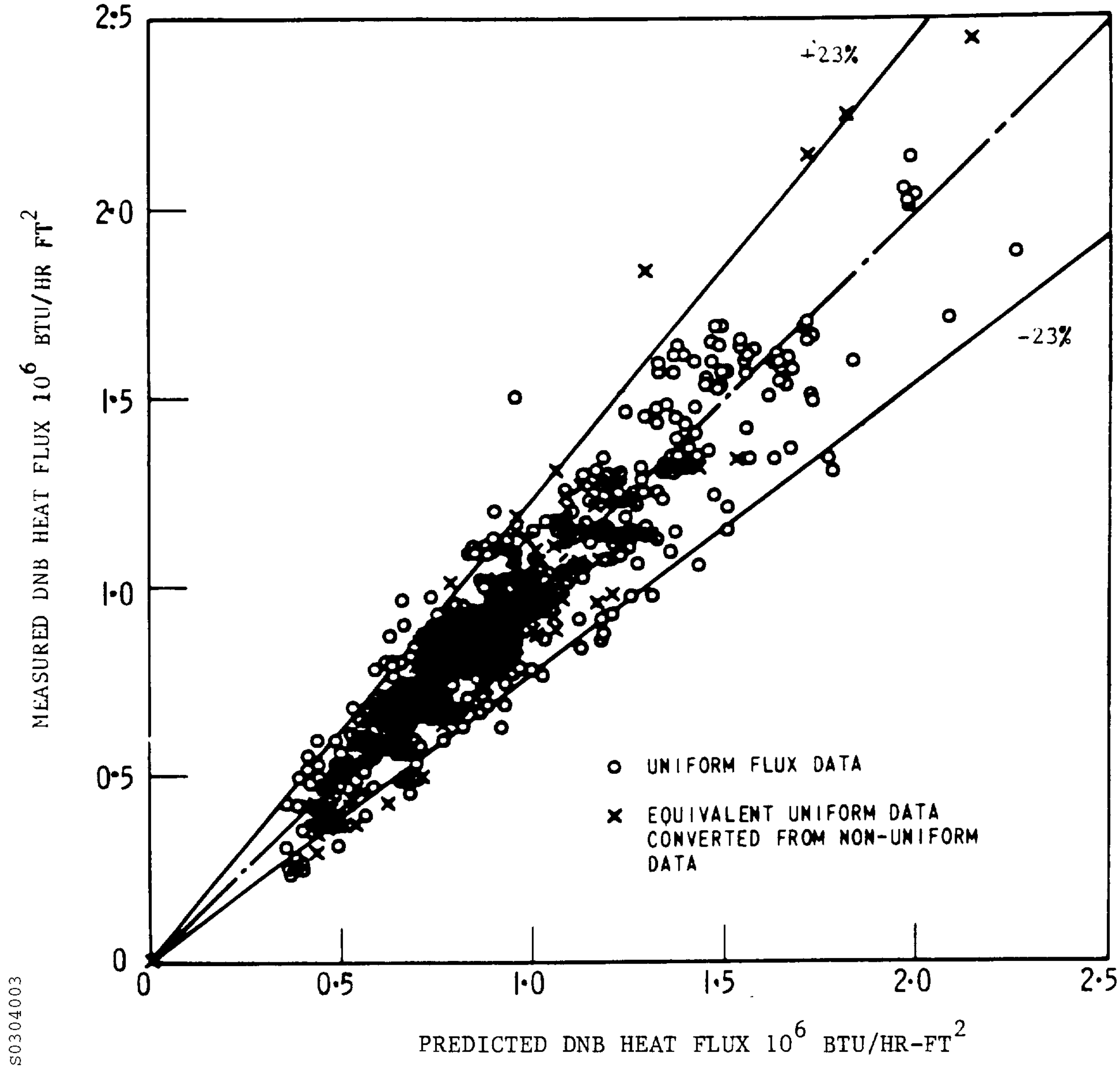


Figure 3.4-4
W-3 CORRELATION PROBABILITY DISTRIBUTION CURVE

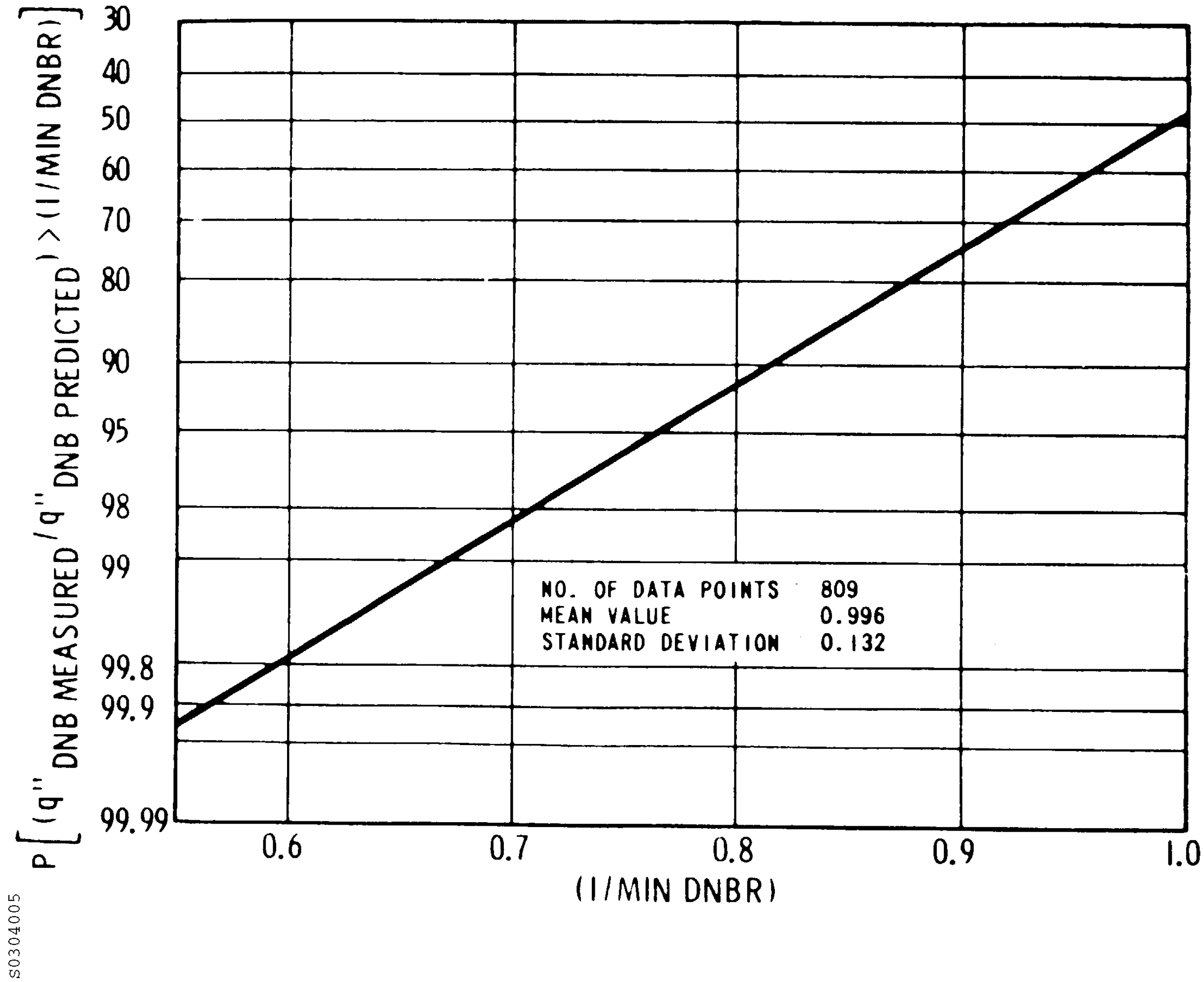


Figure 3.4-5
COMPARISON OF W-3 CORRELATION WITH ROD BUNDLE DNB DATA
(SIMPLE GRID WITHOUT MIXING VANE)

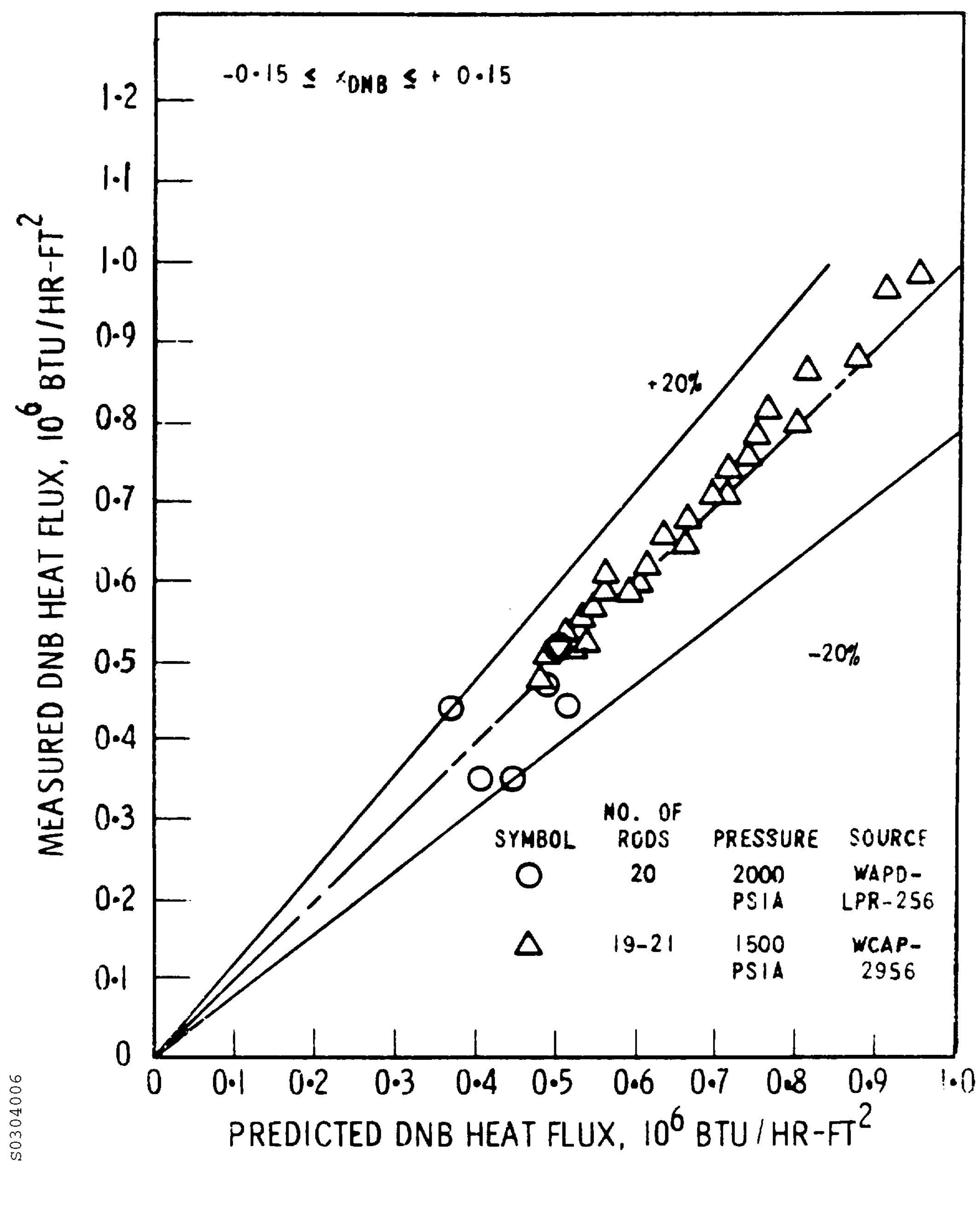
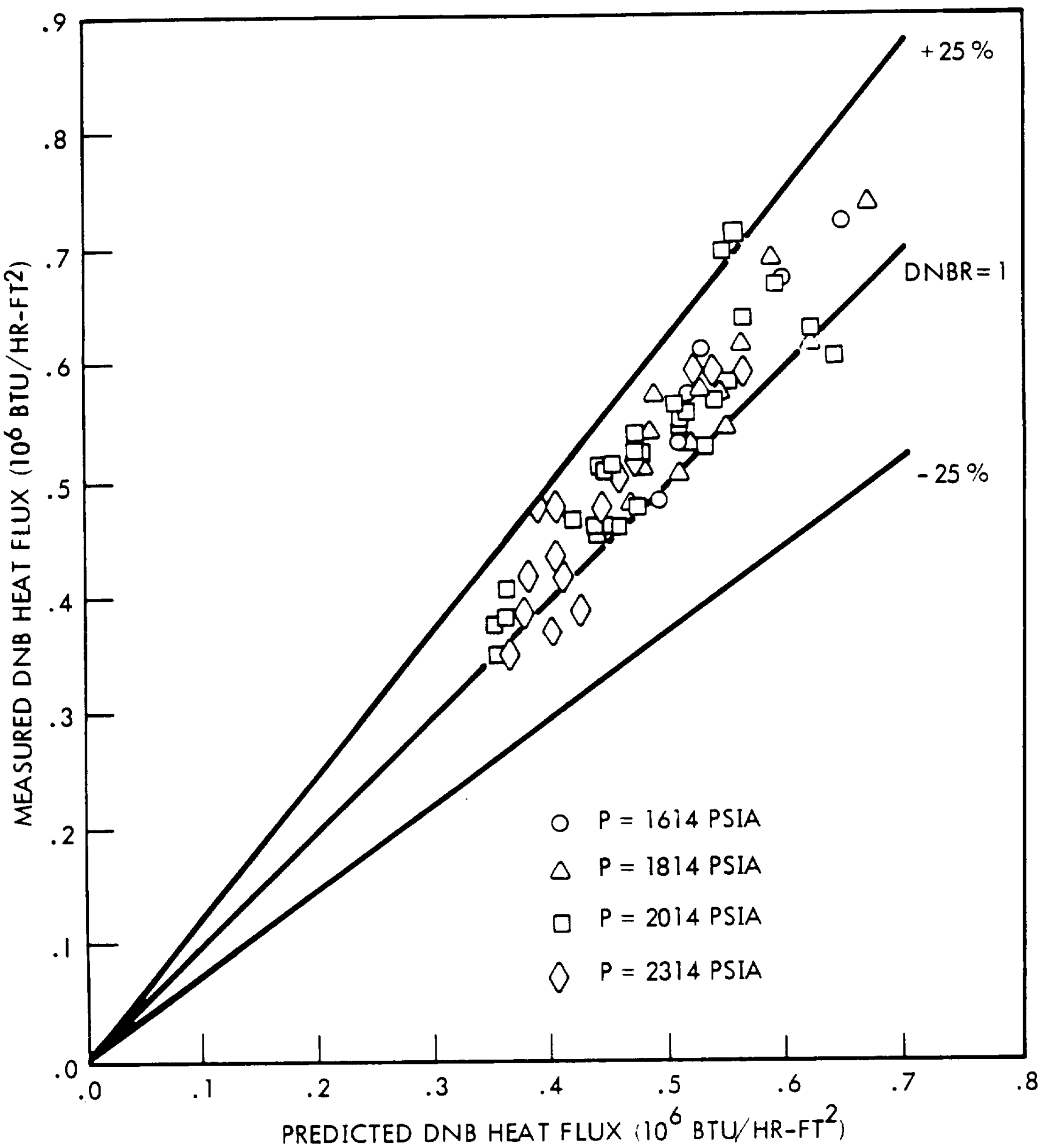


Figure 3.4-6
COMPARISON OF W-3 CORRELATION WITH ROD BUNDLE DNB DATA
(SIMPLE GRID WITH MIXING VANE)



S0304007

Figure 3.4-7
MEASURED VERSUS PREDICTED CRITICAL HEAT FLUX WRB-1 CORRELATION

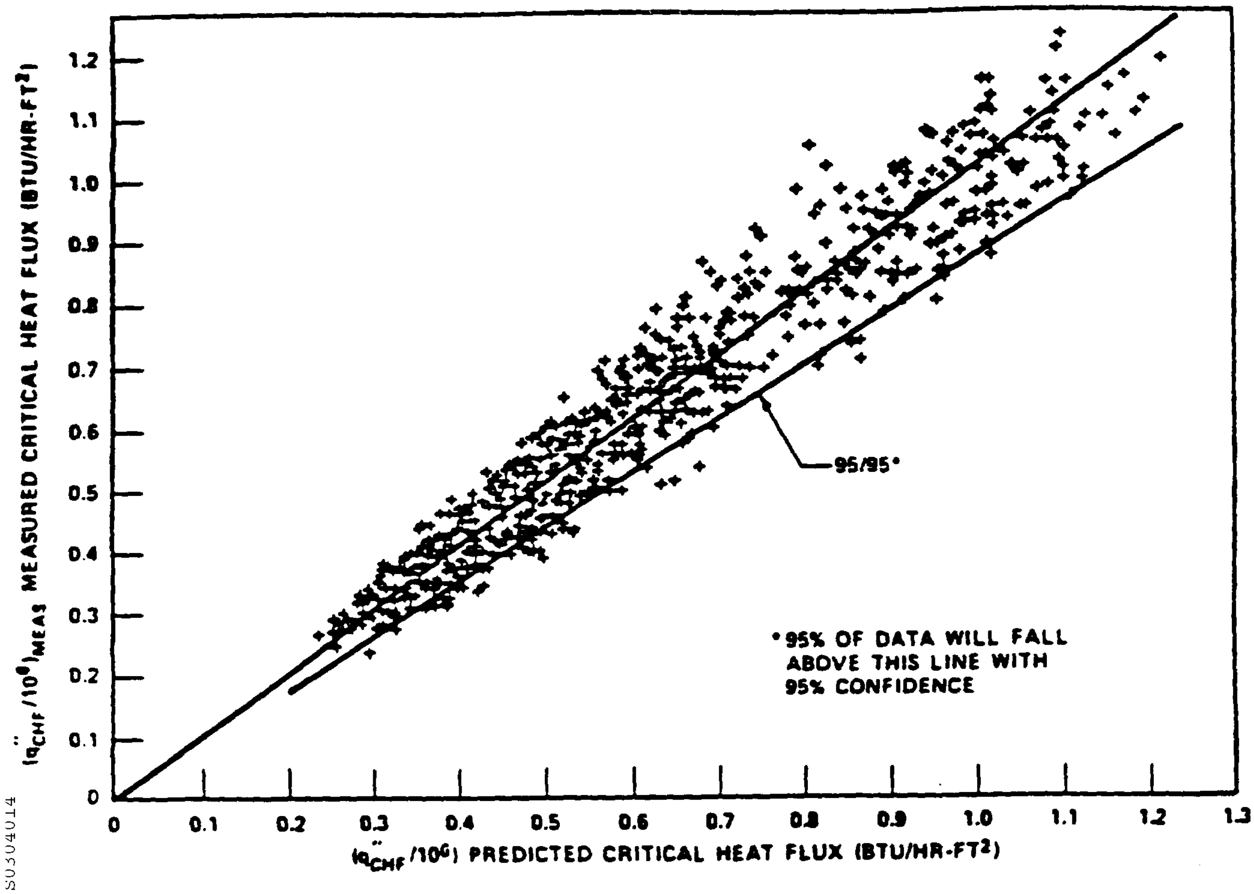


Figure 3.4-8
COMPARISON OF NON-UNIFORM DNB DATA WITH W-3 PREDICTIONS

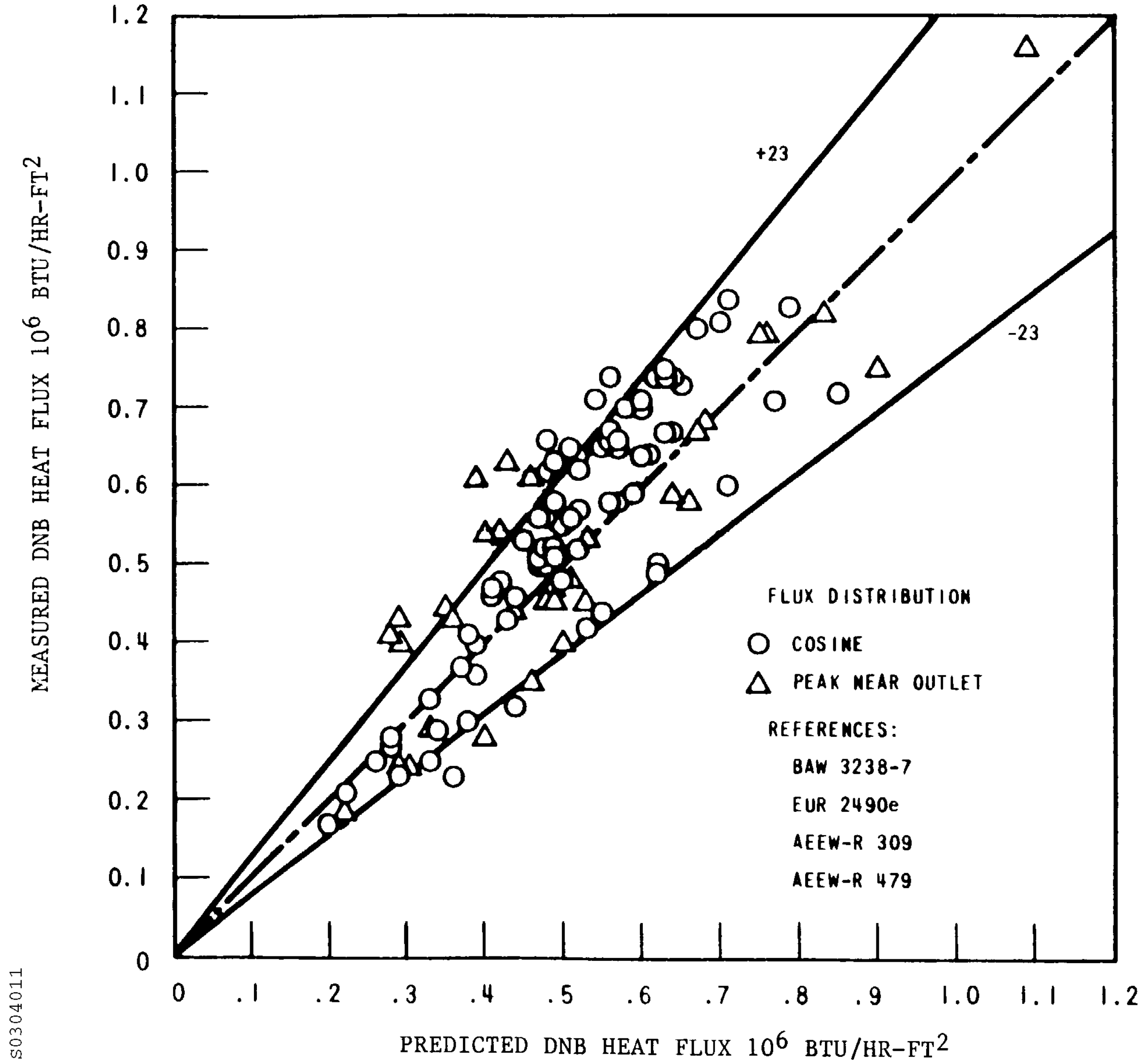
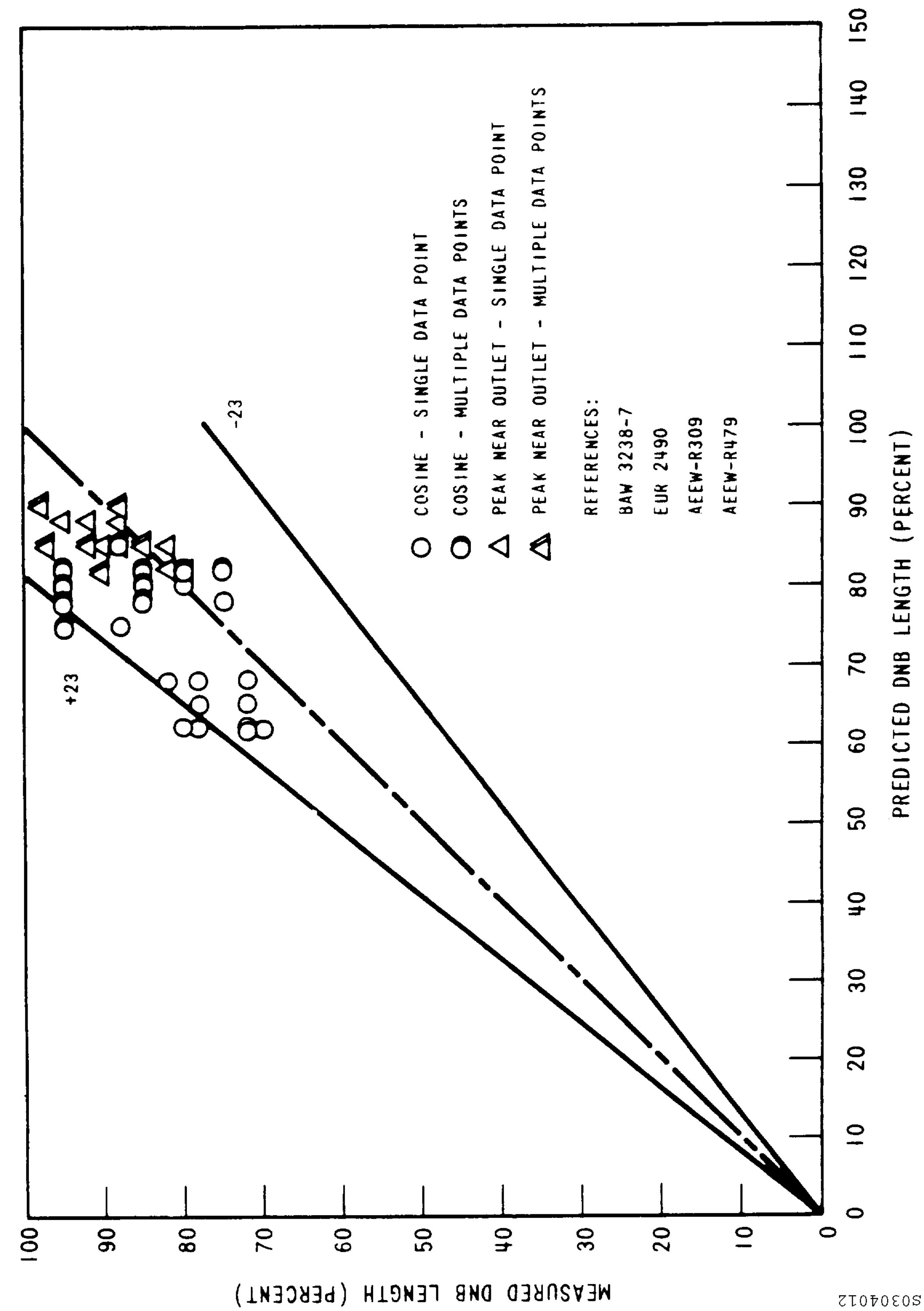


Figure 3.4-9
COMPARISON OF W-3 PREDICTION WITH MEASURED DNB LOCATION



3.5 MECHANICAL DESIGN

The reactor core cross section and reactor vessel internals are shown in Figures 3.5-1 and 3.5-2, respectively. The core, consisting of the fuel assemblies, control rods, source rods, and guide thimble plugging devices, provides and controls the heat source for reactor operation. The internals, consisting of the upper and lower core support structure, are designed to support and orient the fuel assemblies and control rod assemblies, direct the coolant flow to and from the core components, and support and guide the incore instrumentation. A listing of the mechanical design parameters of the initial cores is given in Table 3.5-1.

The fuel assemblies are arranged in a roughly circular cross-sectional pattern. The assemblies within a region are identical in configuration, but contain fuel of different enrichments depending on the location of the assembly within the core. Small differences may exist between different regions of fuel, as new design features are incorporated into reload fuel assemblies. The fuel is in the form of slightly enriched uranium dioxide ceramic pellets. The pellets are stacked to an active height of 144 inches within Zircaloy-4, ZIRLO, or Optimized ZIRLO tubular cladding, which is then plugged and seal-welded at the ends to encapsulate the fuel.

The core is divided into regions of several different enrichments. The loading arrangement for the initial cycle is indicated on Figure 3.5-3. Refueling generally takes place in accordance with an in-out movement schedule. The enrichments of the fuel for the three fuel regions in the first core cycle are given in Table 3.5-1. Limitations on the enrichment of reload fuel are provided in the Technical Specifications.

The fuel rods of all regions are internally pressurized with helium during fabrication. Heat generated by the fuel is removed by demineralized borated light water, which flows upward through the fuel assemblies and acts as both moderator and coolant.

The control rod assemblies consist of groups of individual control rods supported by a spider at the top end and thereby actuated as a group. In the inserted position, the control rods fit within hollow guide thimbles in the fuel assemblies. The guide thimbles are an integral part of the fuel assemblies and occupy locations within the regular fuel assembly pattern where fuel rods have been deleted. In the withdrawn position, the control rods are guided and supported laterally by guide tubes forming an integral part of the upper core support structure. Figure 3.5-4 shows the typical fuel assembly structural components and a control rod assembly. The relative positions of the control rods in a fuel assembly are shown in Figure 3.5-5.

As shown in Figure 3.5-2, the fuel assemblies are positioned and supported vertically in the core between the upper and lower core plates. The core plates are provided with pins that index into closely fitting mating holes in the fuel assembly top and bottom nozzles. The pins maintain the fuel assembly alignment, permitting free movement of the control rods.

Operational or seismic loads imposed on the fuel assemblies are transmitted through the core plates to the upper and lower core support structures. Vertical loads are transmitted to the internals support ledge at the pressure vessel flange. Horizontal loads are transmitted to the lower radial support and internals support ledge. The internals also provide a form-fitting baffle surrounding the fuel assemblies, confining the upward flow of most of the coolant in the core area to the fuel-bearing region.

3.5.1 Reactor Internals

The reactor internals are designed to support and orient the fuel assemblies and control rod assemblies. The internals also absorb the control rod assembly dynamic loads and transmit these and other loads to the reactor vessel flange, provide a passageway for the reactor coolant, and support incore instrumentation. The reactor internals are shown in Figure 3.5-2. The internals are designed to withstand the combination of forces due to weight, preload of fuel assemblies, differential hydraulic pressure, control rod assembly dynamic loading, vibration, and earthquake acceleration. The internals were analyzed similarly to those of Connecticut Yankee (Haddam Neck), San Onofre, Jose Cabrera (Spain), Saxton, and Yankee (Rowe). The structure satisfies stress values prescribed in the ASME Code, Section III, Nuclear Vessels. The dynamic criteria for design and the stress levels of the internals in each unit are similar to those used for Connecticut Yankee.

The Surry Unit 1 reactor internals have been modified to change the flow path of the reactor coolant from downflow between the core barrel and baffle plates to an upflow direction. This was accomplished by plugging the core barrel flow holes and creating new flow holes in the top former plate.

The internals are designed to the criteria stated in Chapter 15, including Appendix 15A.

The reactor internals are equipped with bottom-mounted incore instrumentation supports. These supports are designed to sustain the applicable loads outlined above.

In a hypothesized downward vertical displacement of the internals, energy-absorbing devices would limit the displacement by contacting the vessel bottom head. The load is transferred through the energy-absorbing devices to the vessel. The cylindrically shaped energy absorbers are contoured on their bottom surface to the reactor vessel bottom head geometry. Their number (four) and design are determined so as to limit the forces imposed to a safe fraction of yield strength. Assuming a downward vertical displacement, the potential energy of the system is absorbed mostly by the strain energy of the energy-absorbing devices.

In the unlikely event that the normal core support structure fails, the energy-absorbing devices would limit the fall of the core as well as absorb the energy of the drop which would otherwise be imparted to the vessel. The energy of fall was calculated assuming a complete and instantaneous failure of the primary core support and would be absorbed during the plastic deformation of a controlled volume of stainless steel, loaded in tension, in each device. The maximum deformation of this austenitic stainless piece would be limited to approximately 15%, after which a positive stop is provided to ensure support. Standard textbook calculations were used to derive the amount of strain.

The displacement in the hot condition is on the order of 0.5 inch, and there is an additional strain displacement in the energy-absorbing devices of approximately 0.75 inch. Alignment features in the internals prevent cocking of the internals structure during this postulated displacement so that the control rod assemblies are able to be inserted upon trip. The displacement distance of about 1.25 inches is not enough to cause the tip of any of the control rods to come out of the guide thimbles.

The components of the reactor internals are divided into three parts, consisting of the lower core support structure, including the entire core barrel and thermal shield, the upper core support structure, and the incore instrumentation support structure.

3.5.1.1 **Lower Core Support Structure**

The major containment and support member of the reactor internals is the lower core support structure, shown in Figure 3.5-6. This support structure assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the thermal shield, the intermediate diffuser plate, and the bottom support plate, which are welded to the core barrel. All the major material for this structure is type 304 stainless steel. The core support structure is supported at its upper flange from a ledge in the reactor vessel head flange, and its lower end is restrained in the transverse direction by a radial support system attached to the vessel wall. Within the core barrel are axial baffle and former plates, which are attached to the core barrel wall and form the enclosure of the assembled core. The lower core plate is positioned at the bottom level of the core below the baffle plates, and provides support and orientation for the fuel assemblies.

The lower core plate is perforated for flow purposes, and contains the lower locating pins for the fuel assemblies. Columns are placed between this plate and the bottom support plate of the core barrel in order to stiffen this plate and transmit the core load to the bottom support plate.

An intermediate perforated diffuser plate is placed between the bottom support plate and the lower core plate to uniformly diffuse coolant flowing into the core.

The one-piece thermal shield is fixed to the core barrel at the top with rigid bolted connections. The bottom of the thermal shield is connected to the core barrel by means of six axial flexures. This number is consistent with the number of flexures used on other three-loop plants. This bottom support allows for differential axial growth of the shield with respect to the core barrel, but restricts radial or horizontal movement of the bottom of the shield.

The adequacy of the flexures has been evaluated and verified utilizing the information gained from the instrumentation of the thermal shield during the hot-functional test of the three-loop H. B. Robinson Unit 2 reactor. This study was performed by correlating the hot-functional data with tests performed on thermal shields in the manufacturing facilities (determination of normal modes, natural frequency and flexure stresses). The result of these analyses indicates an adequate margin based on the criteria of Section III of the ASME Code.

In the event of a failure of the flexures, the thermal shield will remain fixed at the top and will become free at the bottom. Mechanical shaker tests performed on actual thermal shields indicate that the vibration effects will not affect the structural adequacy of the thermal shield support, with stress levels remaining within the limits of Section III of the ASME Code.

Irradiation baskets in which encapsulated materials samples can be inserted and irradiated during reactor operation are attached to the outer side of the thermal shield (Section 4.1.7).

The lower core support structure, consisting principally of the core barrel, serves to provide passageways and control for the coolant flow. Inlet coolant flow from the vessel inlet nozzles proceeds down the annulus between the core barrel and the vessel wall, on both sides of the thermal shield, and into a plenum at the bottom of the vessel. It then turns and flows up through the bottom support plate, passes through the intermediate diffuser plate and then through the lower core plate. The flow holes in the diffuser plate are arranged to prevent gross inlet flow maldistribution to the core. After passing through the core, the coolant enters the area of the upper support structure and then generally flows radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles.

A small amount of water also flows between the baffle plates and core barrel to provide additional cooling of the barrel. Similarly, a small amount of the entering flow is directed into the vessel head plenum and exits through the vessel outlet nozzles.

Downward-directed loads from weight, fuel assembly preload, control rod assembly dynamic loading, and earthquake acceleration are carried by the lower core plate partially into the lower core plate support flange on the core barrel and partially through the lower support columns into the bottom support plate. Finally, the load enters through the core barrel and ends in the core barrel flange supported by the vessel head flange. Transverse loads are carried by the core barrel to be shared by the lower radial support and the vessel head flange. Loads resulting from transverse acceleration of the fuel assemblies are transmitted to the core barrel by connections of the lower core support plate and a radial support-type connection of the upper core plate, as shown in Figure 3.5-7.

The main radial support system for the lower end of the core barrel is accomplished by “key” and “keyway” joints to the reactor vessel wall. At four equally spaced points around the circumference, Inconel blocks are welded to the vessel inside wall. Each of these blocks has a “keyway” geometry. Opposite each of these is a “key” that is attached to the barrel. During assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction. With this design, the internals are provided with a support at their extremities, and may be viewed as a beam fixed at the top and simply supported at the bottom.

Radial and axial expansions of the core barrel are accommodated, but transverse movement of the core barrel is restricted by this design. Cycle stresses in the internal structures are within the limits of ASME Code Section III, thus eliminating any possibility of failure of the core support.

3.5.1.2 **Upper Core Support Assembly**

The upper core support assembly, shown in Figure 3.5-7, consists of the top support plate, deep beam sections, upper core plate, support columns, and guide tube assemblies. The support columns establish the spacing between the top support plate, deep beam sections, and the upper core plate, and are fastened at top and bottom to these plates and beams. The support columns transmit the mechanical loadings between the two plates. The guide tube assemblies, shown on Figure 3.5-8, sheath and guide the control rod assembly drive shafts and control rod assembly, and provide no other mechanical functions. They are fastened to the top support plate and are guided by pins in the upper core plate for proper orientation and support. Additional guidance for the control rod assembly drive shafts is provided by the control rod assembly shroud tube, which is attached to the upper support plate and guide tube.

The upper core support assembly, which is removed as a unit during the refueling operation, is positioned in its proper orientation with respect to the lower support structure by flat-sided pins pressed into the core barrel, which in turn engage in slots in the upper core plate. At an elevation in the core barrel where the upper core plate is positioned, the flat-sided pins are located at equal angular positions. Slots are milled into the core plate at the same positions. As the upper support structure is lowered into the main internals, the slots in the plate engage the flat-sided pins in the axial direction. Lateral displacement of the plate and of the upper support assembly is restricted by this design.

Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper core support assembly is lowered into place. Proper alignment of the lower core support structure, the upper core support assembly, and the fuel and control rod assemblies is ensured by this guidance arrangement. The upper core support assembly is restrained from any axial movements by a large circumferential spring located between the upper barrel flange and the upper core support assembly. This spring is compressed by the reactor vessel head flange when the closure bolts are tightened.

Vertical loads from hydraulic loads, earthquake acceleration, and fuel assembly preload are transmitted through the upper core plate via the support columns to the deep beams and top support plate to the reactor vessel head. Transverse loads from coolant cross flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the top support plate and upper core plate. The top support plate is particularly stiffened to minimize deflection.

3.5.1.3 **Incore Instrumentation Support Structures**

The incore instrumentation support structure consists of bottom mounted instrumentation thimble guides that carry the retractable flux thimble thermocouples through the bottom of the vessel. The flux thimble thermocouples consist of a detector path to allow measurement of neutron flux and thermocouples to measure core exit temperature.

Conduits extend from the bottom of the reactor vessel down through the primary concrete shield area and up to a thimble seal table. The trailing ends of the thimbles at the seal table are extracted approximately 15 feet during refueling of the reactor in order to avoid interference within the core. The thimbles are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere.

Mechanical seals between the retractable thimbles and the conduits are provided at the seal table. During normal operation, the retractable thimbles are stationary and are retracted only during refueling or for maintenance. Chapter 7 contains more information on the layout of the incore instrumentation system.

The incore instrumentation support structure is designed for adequate support of instrumentation during reactor operation, and for resisting damage or distortion during refueling.

3.5.1.4 **Evaluation of Core Barrel and Thermal Shield**

The core internals design is based on the experience gained from previous analyses, tests, and operational results. Data from previous Westinghouse pressurized water reactors was evaluated, and information derived was considered in the Surry design. For example, Westinghouse used a one-piece thermal shield that is attached rigidly to the core barrel at one end and permitted to flex at the other. The earlier designs were multi-piece thermal shields that rested on vessel lugs and were not rigidly attached to the top.

Early core barrel designs employed threaded connections, such as tie rods, that joined the bottom support to the bottom of the core barrel, and a bolted connection that attached the core barrel to the upper barrel. Such designs were associated with thermal shield oscillation, which created forces on the core barrel. Other forces were induced by unbalanced flow in the lower plenum of the reactor. In subsequent control rod assembly designs, fuel followers and a large bottom plenum in the reactor have not been required.

The reactor core barrel incorporates improvements based on the Connecticut Yankee (Haddam Neck) and the Jose Cabrera (Spain) reactor core barrels. Deflection-measuring devices employed in the Connecticut Yankee and the Jose Cabrera reactors during hot-functional testing, and strain gauges employed in the Jose Cabrera reactor, provided important information for use in the design of the internals. Careful inspections of Connecticut Yankee and Jose Cabrera reactor internals such as structural welds, nozzle interfaces, upper core plate supports, and thermal shield attachments uncovered no defects.

Substantial scale model testing was performed by Westinghouse. These tests included a complete full-scale fuel assembly operating at reactor flow, temperature, and pressure conditions. Tests were also run on a one-seventh scale model of the Indian Point Unit 2 reactor. Results of these tests indicated movement of only a few mils at full scale. Strain gauge measurements taken on the core barrel also indicated very low stresses. Testing to determine thermal shield excitation due to inlet flow disturbances was also performed. Information gathered from these tests was then used in the design of the thermal shield and core barrel.

3.5.2 Core Components

3.5.2.1 Fuel Assembly

All of the fuel assemblies prior to Batch 12 (also referred to as Region 12) of both Surry units were of the 15 x 15 LOPAR design. Fuel assemblies from Batches 12 through 26 (Unit 1) and Batches 12 through 25 (Unit 2) are of the 15 x 15 SIF design. Fuel assemblies from Unit 1 Batch 27 and Unit 2 Batch 26 and subsequent Batches are of the 15 x 15 Upgrade design. The LOPAR, SIF, and 15 x 15 Upgrade assemblies are of similar design, and their overall configurations are shown in Figure 3.5-9. A comparison of nominal design features of the 15 x 15 LOPAR, 15 x 15 SIF, and 15 x 15 Upgrade assemblies is found in Table 3.5-3. The assemblies are square in cross section, nominally 8.426 inches on a side, and have a fuel column nominal height of 144 inches. The overall height of the 15 x 15 LOPAR assembly is 159.71 inches, while the overall height of the Zircaloy SIF and 15 x 15 Upgrade assemblies is 159.975 inches. The overall height of the ZIRLO SIF ranges from 159.775 inches to 159.975 inches.

Beginning with Batch 16 at both units, the Surry fuel assemblies include fuel rod cladding, guide thimbles, instrumentation tubes and mixing vane grids fabricated from ZIRLO (Reference 8). This advanced zirconium alloy was incorporated to improve the corrosion resistance of the fuel. ZIRLO is also dimensionally more stable than Zircaloy under irradiation, but most other properties (e.g., yield strength) are very similar to Zircaloy-4. Minor changes to some as-built dimensions (e.g., fuel rod length) were made to reflect the different behavior of the ZIRLO alloy. The as-built fuel assembly length was decreased slightly (to approximately 159.8 inches, between the LOPAR and Zircaloy-4 SIF assembly lengths) to allow for assembly growth to higher burnups. The fuel assembly envelope dimensions remained unchanged.

Additional changes to the fuel design introduced with 15 x 15 Upgrade include guide thimble tube-in-tube dashpots, balanced vane structural mid-grids, three non-structural Intermediate Flow Mixing grids (IFMs), shorter fuel rod end plugs than those used in later batches of SIF fuel (discussed below), and an oxide coating on the lower portion of the fuel rod cladding. A comparison of the 15 x 15 Upgrade and SIF designs (Figure 3.5-17) shows the addition of the IFMs and the relative grid heights.

The 15 x 15 Upgrade fuel rod cladding is fabricated of Optimized ZIRLO. (The 15 x 15 Upgrade guide thimbles, instrumentation tubes, mixing vane grids, and Intermediate Flow Mixing grids are fabricated of ZIRLO.) Optimized ZIRLO is incorporated to further reduce the fuel clad corrosion rate while maintaining the composition and physical properties, such as mechanical strength, similar to standard ZIRLO.

The fuel rods in a LOPAR, SIF, and 15 x 15 Upgrade fuel assembly are arranged in a square array with 15 rod locations per side and a nominal centerline-to-centerline pitch of 0.563 inch between rods. Of the total possible 225 rod locations per assembly, 20 are occupied by guide thimbles for the control rods and burnable poison rods, and one central thimble is reserved for incore instrumentation. The remaining 204 locations contain fuel rods. In addition to fuel rods, a fuel assembly also includes a top nozzle, a bottom nozzle, and seven structural grid assemblies. The five structural (mixing vane) mid-grids on the SIF assemblies are Zircaloy or ZIRLO and on the 15 x 15 Upgrade assemblies are ZIRLO, while the two end grids are Inconel. The 15 x 15 Upgrade assemblies also add three IFMs, fabricated of ZIRLO, located in the hottest spans between structural grids. The IFM region is located between the third and sixth mid-grids, where each IFM is located between mid-grids as shown in Figure 3.5-17. The IFMs do not provide structural support for the assembly. All seven grids on the LOPAR assembly are made of Inconel.

Beginning with Region 15, a protective Inconel grid was added directly above the bottom nozzle to enhance debris resistance. Some minor changes to the fuel rod were also made in conjunction with use of the protective grid.

These include: use of a slightly longer bottom end plug which, together with repositioning the rods to directly above the bottom nozzle, ensures a solid metal interface between the protective grid and the fuel rod; and use of an external grip top end plug to facilitate rod positioning during manufacturing of assemblies with protective grids.

Further small dimensional changes were made to the fuel starting with Surry 2 Batch 20. The fuel assembly length was increased to match the Zircaloy-4 SIF design (159.975 inches) and the fuel rod length was increased by a comparable amount, as indicated in Table 3.5-3, to take advantage of the low growth rate of ZIRLO. The external grip feature was also removed from the fuel rod top end plug, slightly decreasing its length. These changes allowed use of a slightly longer bottom end plug on the fuel rods, to enhance debris resistance, as well as a minor increase in the fuel rod plenum volume, providing a small benefit for rod internal pressure analyses.

The 15 x 15 Upgrade design also incorporates these features, except it is equipped with the slightly shorter bottom end plug design that SIF fuel had prior to Surry Unit 1 Batch 21 and Surry Unit 2 Batch 20. The shorter bottom end plug increases the upper plenum length while retaining the overall fuel rod length and the active fuel length. However, this end plug design still ensures a solid metal interface between the protective grid and the fuel rod. Also, the outer part of the bottom end plug and weldment, and the bottom portion of the outer fuel cladding on the 15 x 15 Upgrade are oxidized to improve debris resistance.

Beginning with Batch 28, the Robust Protective Grid and modified Debris Filter Bottom Nozzle were incorporated into the 15 x 15 Upgrade assemblies. The Robust Protective Grid and modified debris Filter Bottom Nozzle provide enhanced debris filtering capabilities and improved resistance to fatigue failure.

Beginning with Batch 29, the Westinghouse Integral Nozzle (WIN) top nozzle design has been introduced in new Westinghouse fuel batches. This nozzle design eliminates threaded fasteners from the nozzle to reduce the risk of loose parts.

Beginning with Batch 33 for both units, the Westinghouse Conventional Manufactured Advanced Debris Filter Bottom Nozzle (ADFBN) replaced the modified Debris Filter Bottom Nozzle (mDFBN) on the 15x15 Upgrade fuel assembly design. The ADFBN design is similar to the mDFBN design as it has the same adapter plate flow hole design and flow hole pattern and thus has the same loss coefficient. The ADFBN design, however, lowered the side skirts to help improve the debris filtering capability of the bottom nozzle by eliminating the large lateral flow path between the bottom nozzle legs in the mDFBN design. Small flow holes were added to the new skirt to maintain flow to the baffle-former region while still reducing the overall lateral flow path available to debris.

The 21 guide thimbles, in conjunction with the grid assemblies and the top and bottom nozzles, comprise the basic structure of the fuel assembly. The top and bottom ends of the guide thimbles are fastened to the top and bottom nozzles, respectively. The grid assemblies are fastened to the guide thimbles at each location along the height of the fuel assembly at which lateral support for the fuel rods is required. The fuel rods are contained and supported, and the rod-to-rod centerline spacing is maintained along the assembly within this skeletal framework.

Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. Small numbers of demonstration or lead fuel assemblies which differ from the fuel described in Chapter 3 or that have not completed representative testing may be used in the Unit 1 or Unit 2 cores in non-limiting locations. These assemblies will be substantially the same as the fuel described in Chapter 3, but may incorporate some dimensional, material, or mechanical differences which would be described in the appropriate supporting licensing documentation (e.g. license amendment, exemption request, or 10 CFR 50.59 evaluation). The effects of operation with demonstration or lead assemblies will be assessed for each reload core in which they are irradiated to demonstrate that all reload safety requirements are satisfied. Demonstration assemblies with 17 rod locations per side in a square array have been used in the past in the Surry reactors. The assemblies were used to demonstrate the feasibility of extended discharge burn-ups. WCAP 8362 (Reference 1) concludes that the presence of 17 x 17 demonstration assemblies does not adversely affect reactor performance relative to an all 15 x 15 assembly core.

Reconstituted fuel assemblies, which contain small numbers of non-fueled solid zircaloy or stainless steel rods in the place of failed fuel rods, may be used in Surry reload cores. Assemblies which have low burnup and have been determined to contain failed rods may be reconstituted to allow for the continued utilization of the energy remaining in the fuel assembly. The non-fueled rods are manufactured from solid zircaloy or stainless steel, may be slightly oversize in diameter to compensate for grid spring relaxation and any grid degradation that may occur during failed rod removal, and have a tapered end to ease insertion and prevent grid damage. In Reference 5, NRC concurred that the presence of reconstituted assemblies does not adversely affect reactor performance or safety relative to a core containing no reconstituted assemblies.

3.5.2.1.1 Bottom Nozzle

The bottom nozzle is a square pedestal structure which controls the coolant flow distribution to the fuel assembly and functions as the bottom structural element of the fuel assembly. The nozzle is fabricated from stainless steel similar to type 304, and it consists of a perforated plate joined to four angle legs with pads or feet and side skirts which help support the legs and also help preclude debris from traveling around the bottom nozzle. The plate, legs and side skirts form a plenum space for the inlet coolant flow into the fuel assembly. The perforated plate serves as the bottom end support for the fuel rods. The bottom support surface for the fuel assembly is formed under the plenum space by the four pads at the bottom of the angle legs.

The guide thimbles, which carry axial loads imposed on the assembly, are fastened to the bottom nozzle plate. These loads, as well as the weight of the assembly, are distributed through the nozzle to the lower core support plate. Indexing and positioning of the fuel assembly in the core is fixed by two holes in diagonally opposite pads, which mate with two locating pins in the lower core plate. Lateral loads imposed on the fuel assembly are also transferred to the core support structures through the locating pins.

3.5.2.1.2 Top Nozzle

The top nozzle is a square box-like structure that functions as the fuel assembly upper structural element and forms a plenum space where the heated reactor coolant mixes and is directed toward the flow holes in the upper core plate. The nozzle is comprised of an adaptor plate, nozzle enclosure, top plate, two clamps, holddown springs, and assorted hardware. The LOPAR assemblies had single- or double-leaf holddown springs, while the SIF and 15 x 15 Upgrade assemblies have a three-leaf spring. All parts with the exception of the springs and their holddown bolts are constructed of stainless steel similar to type 304. The springs are made from age-hardenable Inconel 718, and the bolts from Inconel 600 or Inconel 718. Beginning with Batch 29, the Westinghouse Integral Nozzle (WIN) top nozzle design has been implemented on all new Westinghouse fuel assemblies. Holddown bolts were eliminated from the WIN design and replaced with retaining pins. The top nozzle and pins are also constructed of stainless steel similar to type 304. The WIN design uses a three-leaf spring made of the same material used in previous nozzle designs. The WIN is mechanically attached to the fuel assembly in the same way as the original SIF and 15 x 15 Upgrade removable top nozzle design.

The adaptor plate is square in cross-section, and is perforated by machined slots to provide for coolant flow through the plate. On LOPAR fuel assemblies, the top ends of the guide thimble adaptors are welded to the adaptor plate. In the original SIF and 15 x 15 Upgrade assembly removable top nozzle design, the guide thimble adaptors are mechanically attached to the adaptor plate as described in Reference 6. Thus, the adaptor plate, which acts as the fuel assembly top end plate, provides a means of distributing evenly among the guide thimbles any axial loads imposed on the fuel assemblies, and limits any excessive axial movement of fuel rods.

The nozzle enclosure is a square thin-walled shell that forms the plenum section of the top nozzle. The bottom end of the enclosure is welded to the periphery of the adaptor plate, and the top end joins the periphery of the top plate.

The top plate is square in cross-section, with a large central opening. The opening allows clearance for the control rods to pass into the guide thimbles in the fuel assembly, and provides for coolant exit from the fuel assembly into the upper internals area. Two pads containing axial through-holes, located on diametrically opposite corners of the top plate, provide a means of positioning and aligning the top of the fuel assembly. Like the bottom nozzle, alignment pins in the upper core plate mate with the holes in the top nozzle plate.

Holddown forces of sufficient magnitude to oppose the hydraulic lifting forces on the fuel assembly are obtained by means of the leaf springs, which are mounted on the top plate. The springs are fastened in pairs to the top plate at the two corners where alignment holes are not located, and extend out from the corners parallel to the sides of the plate. On LOPAR fuel assemblies, each pair of springs is fastened with a clamp that fits over the ends of the springs. Each clamp is secured with two bolts, which pass through the clamp and springs and thread into the top plate. At assembly, the spring-mounting bolts are torqued sufficiently to preload against the maximum spring load, and then are lock-welded to the clamp, which is counter-bored to receive the bolt head. On the SIF and 15 x 15 Upgrade fuel assemblies, attachment of the holddown springs was modified. The counterbore was eliminated from the clamp design, allowing the holddown spring screws to bear directly on the springs. The clamp, which is tack welded to the top nozzle, continues to fit over the end of the springs, and acts as a cover for the screw heads. A lock wire that is welded to the clamp ensures that the spring screws remain in position during operation. On 15 x 15 Upgrade fuel assemblies with the WIN top nozzle design, attachment of the holddown springs was modified. The holddown springs screws were eliminated entirely. Instead, the tail end of the holddown spring pack slides into a blind pocket machined into the top nozzle casting. The spring pack is held in place by a retaining pin pushed vertically through the pocket and springs. The pin is tack welded to the top nozzle to secure it in position. The WIN spring design has a rounded tail and the tang and tang windows are centered, creating a same-hand spring.

The spring load is obtained through deflection of the spring by the upper core plate. The spring projects above the fuel assembly and is depressed by the core plate when the internals are loaded into the reactor. The free end of the spring is bent downward and is captured in a slot in the top plate. This is done to guard against release of loose parts in the reactor in the event (however remote) of spring fracture.

In addition, the fit between the upper spring and slot and between the spring set and the mating slot in the clamp is sized to prevent rotation of either end of the spring set into the control rod path in the event of spring fracture.

In addition to its plenum and structural functions, the nozzle provides a protective housing for components that mate with the fuel assembly. In handling a fuel assembly with a control rod assembly inserted, the control rod assembly spider is protected by the nozzle. During operation in the reactor, the top nozzle protects the control rods from coolant cross flows in the unsupported span between the top nozzle adaptor plate and the end of the guide tube in the upper internals package. Other fuel insert components that mate with the fuel assembly thimble tubes, such as plugging devices, source assemblies, flux suppression inserts and burnable poison assemblies, are similarly protected by the top nozzle of the fuel assembly.

3.5.2.1.3 Guide Thimbles

The control rod guide thimbles in the fuel assembly provide guide channels for the control rods during insertion and withdrawal. The guide thimbles are fabricated from a single piece of Zircaloy-4 or ZIRLO tubing, which is drawn to two different diameters. The larger inside diameter at the top provides a relatively large annular area for rapid insertion during a reactor trip. It also accommodates a small amount of upward cooling flow during normal operations. The bottom portion of the guide thimble has a smaller diameter to cause a dashpot action when the control rods approach the end of travel in the guide thimbles. The transition zone at the dashpot section is conical in shape so that there are no rapid changes in diameter in the tube.

Flow holes are provided just above the transition of the two diameters to permit the entrance of cooling water during normal operation, and to accommodate the outflow of water from the dashpot action during reactor trip.

The control rod guide thimbles are closed at the bottom by means of a welded end plug. The end plugs are subsequently fastened to the bottom nozzle during fuel assembly fabrication. Flow holes are provided in the end plugs to permit entrance of cooling water during normal operation and to regulate dashpot action during control rod trip. The instrumentation thimble is left open at the bottom to receive the incore instrumentation.

The 15 x 15 Upgrade guide thimble incorporates the tube-in-tube dashpot design. The tube-in-tube design utilizes a separate dashpot tube assembly that is inserted into the guide thimble assembly and bulged into place. This design enhances stability thus providing more margin to guide thimble and assembly bowing, and more margin to incomplete rod insertion.

3.5.2.1.4 Grids

The grid assemblies consist of individual slotted straps that are interlocked in an “egg-crate” arrangement. The Inconel grids (all grids in LOPAR fuel assemblies and end grids in SIF and 15 x 15 Upgrade assemblies) are furnace-brazed to permanently join the straps at their points of intersection. The SIF Zircaloy or ZIRLO grid straps (all mid-grids), the 15 x 15 Upgrade

ZIRLO grip straps (all mid-grids and IFMs) and both designs' Inconel protective grids are permanently joined by welding. Details such as springs, support dimples, mixing vanes, and tabs are punched and formed in the individual straps prior to assembly.

Two types of grid assemblies are used in the 15 x 15 LOPAR fuel assembly. Grids with mixing vanes that project from the upper edges of the straps into the coolant stream are used in the high-heat region of the fuel assemblies to promote mixing of the coolant. A grid of this type is shown in Figure 3.5-11. The grids located at the bottom and top ends of the assembly are of the non-mixing type. They are similar to the mixing type but do not have mixing vanes on the internal straps. Inconel 718 is used for the grid material because of its corrosion resistance and high strength properties. After the combined brazing and solution annealing temperature cycle, the grid material is age-hardened to obtain the material strength necessary to develop the required grid spring forces.

Two types of structural grid assemblies are used in the 15 x 15 SIF and 15 x 15 Upgrade assemblies. The top and bottom grids are the same non-mixing vane grids used in the LOPAR assemblies. The middle mixing vane grids are similar to the mixing vane grids used on the LOPAR assemblies with the exception that they are made of Zircaloy (SIF) or ZIRLO (SIF and 15 x 15 Upgrade). The 15 x 15 Upgrade structural mixing vane mid-grids are slightly shorter than the SIF mixing vane mid-grids to maintain assembly pressure drop similar to the other fuel designs. The shorter mixing vane mid-grids compensate for the IFMs. There are also some dimensional differences between the Inconel and zirconium alloy grid straps to compensate for differences in material strength properties. The Inconel is used for the end grids primarily for its high strength and corrosion resistance. Zirconium-based alloys are now used for the mid-grids primarily for their low neutron absorption properties.

The outside straps on all structural grids contain mixing vanes on their upper edges that also aid in guiding the grids and fuel assemblies past projecting surfaces during handling or core loading and unloading. In addition, there are small tabs projecting downward from the lower edge of the outside straps; the irregular contour of the straps is also for guiding.

On the Batch 15 fuel only (fresh feed to Cycle 13), the orientation of the mixing vane grids was slightly modified, with every other mixing vane grid being rotated 90 degrees in the clockwise direction. The purpose for the rotation was to minimize the susceptibility of the fuel assembly to flow induced vibration. There were no physical or material changes to the grids or their axial positions, and this change did not impact the pressure drops, DNB performance, or other thermal-hydraulic performance of the Surry fuel assembly. However, subsequent testing showed that this change could affect the DNB performance of some (other) fuel designs, so grid rotation was not applied to later batches of Surry fuel.

Starting with Batch 15 of the Surry Units 1 and 2, the fuel assemblies incorporate an additional protective bottom Inconel grid (P-grid), located directly above the bottom nozzle. The straps of the P-grid subdivide the flow holes in the bottom nozzle, reducing the amount and size of debris that can enter the fuel assembly. The P-grid inner grid straps contain paired horizontal dimples that provide coplanar four-point contact within each grid cell. (To accommodate the coplanar dimples, alternating cells have the dimples at alternating elevations.) The P-grid is designed to have its dimples on the full diameter of the fuel rod's solid bottom end plug throughout the design life of the fuel assembly.

The protective grid is fabricated from Inconel-718. The straps are welded at the intersects and to the outer grid strap, similar to the Zircaloy and ZIRLO grids. The top of the P-grid outer grid strap retains the anti-snag features used in the top and bottom Inconel grids. The bottom portion of the outer grid strap is bent inward toward the top of the bottom nozzle to minimize potential for hang-up. In addition, the protective grid has a slightly smaller envelope than the bottom non-mixing vane grid and the bottom nozzle to minimize the potential for interaction with other fuel assemblies during handling. The interface between the P-grid, the bottom nozzle, and the fuel rod is illustrated in Figure 3.5-10.

Hydraulic tests showed that the impact of incorporating the protective grids into the fuel assemblies was effectively offset by positioning the fuel rods on the bottom nozzle. The magnitude of the effect on the pressure drop loss coefficients was negligible, so the presence of the protective grid does not change the DNB performance of the fuel.

IFMs are present in the 15 x 15 Upgrade design. IFM grids are considered nonstructural upper assembly grids which contain mixing vanes similar to the structural mid-grids. Specifically, the IFM grids are located in the top three mixing vane grid spans. The IFM grids are neutronically insignificant.

The addition of IFM grids increases pressure drop across the fuel assembly. To alleviate this impact 15 x 15 Upgrade mid-grids utilize an I-spring design that permits a reduced grid height. The inner strap thickness was also decreased to reduce the pressure drop of the grids and thus allow adding IFM grids with minimal impact.

3.5.2.1.5 Fuel Rods

The fuel rods consist of uranium dioxide ceramic pellets contained in slightly cold-worked and partially annealed Zircaloy-4, ZIRLO, or Optimized ZIRLO tubing, which is plugged and seal-welded at the ends to encapsulate the fuel. Sufficient void volume and clearances are provided within the rod to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel swelling due to accumulated fission products without overstressing of the cladding or seal welds. Shifting of the fuel within the cladding is prevented during handling or shipping prior to core loading by a carbon steel or stainless steel helical compression spring that bears on the top of the fuel pellet column. The holddown force to prevent fuel shifting is obtained by compression of the spring between the top end plug and the top of the fuel pellet stack.

Beginning in Cycle 21, each fuel assembly may contain from 0 to 148 integral fuel burnable absorber (IFBA) rods. The IFBA fuel rod design includes a thin layer of boride coating on the outer surface of the majority of the fuel pellets in the fuel rod, as well as axial blankets. The axial blanket is a six-inch (approximate) stack of slightly enriched annular fuel pellets without boride coating located at the top and bottom of the fuel stack in each IFBA rod. Cores may continue to use discrete (fixed) burnable poison rod assemblies in conjunction with IFBA fuel assemblies.

Beginning in Surry Unit 2 Cycle 31, all fuel rods in each new fuel batch may contain axial blankets. The axial blanket is a six-inch (approximate) stack of natural or slightly enriched fuel pellets (solid or annular) located at the top and bottom of the fuel stack in each fuel rod. Axial blankets reduce neutron leakage and improve fuel utilization.

All fuel rods are internally pressurized with helium during fabrication. The fuel rod void space is sized to ensure adherence to the pressure criteria. The rod internal pressure is evaluated for the limiting fuel rod, assuming a conservative operating history. The evaluation is based on expected operating conditions at the peak steady-state power, and also considers the fission gas release from normal operating transients. The model used to predict the quantity of fission gas in the gap is based on an extensive comparison with both published and proprietary data covering a variety of conditions. The internal pressure of the lead rod in the reactor is limited to a value that does not cause the diametral gap to increase due to outward cladding creep during steady state operation, and does not cause extensive DNB propagation to occur.

Additional information on the rod internal pressure design basis can be found in WCAP-17642-P-A (Reference 14).

The fuel pellets are right circular cylinders consisting of slightly enriched uranium dioxide powder, which is compacted by cold pressing and sintering to the required density. The ends of each pellet are dished slightly to allow the greater axial expansion at the center of the pellets to be taken up within the pellets themselves and not in the overall fuel length. Some pellets may have a thin coating of boride material applied to the circumferential surface as discussed in Section 3.5.2.1.5.

A lower pellet density was used in the outer fuel regions of the first core to compensate for the anticipated effects of the higher burn-up experienced in these regions. Reload cores have a uniform nominal pellet density that is slightly higher than those used in the initial core.

The fuel enrichments listed in Table 3.5-1 were used for the three regions in the first core loading. Enrichments used in reload fuel regions are discussed in the reload safety evaluation prepared for each subsequent core cycle.

Each fuel assembly is identified by a serial number engraved on the top nozzle. The fuel pellets are fabricated by a batch process so that only one enrichment region is processed at any given time. The serial numbers of the assemblies and corresponding enrichment are documented and verified by the manufacturer prior to shipment.

Each assembly is assigned a specific core loading position prior to insertion. A record is then made of the core loading position, serial number, and enrichment. Before core loading, two independent reviews are made to ensure that the loading assignment is correct. The serial number is checked before an assembly is loaded into the core. After the core is completely loaded, each serial number is checked again for agreement with the core loading drawing.

Any error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes which are more peaked than those calculated with the correct enrichments. There is an 8% uncertainty margin between the calculated worst value and the design value of $F\Delta h$ assumed for the analysis of normal steady-state operation and anticipated transients. The incore system of movable flux detectors, which is used to verify power distribution limits, is capable of detecting anomalies (such as fuel enrichment errors, core loading errors, or misaligned control rods) that cause peaking factors or core tilts in excess of design values. Power distribution measurements are taken at low power when extremely adverse power distribution can be tolerated. The analysis described below shows that the power increase due to any combination of misplaced fuel assemblies would significantly raise peaking factors and would be readily observable with the incore flux monitors. In addition, thermocouples located in the flux thimbles monitor the outlet of about one-third of the fuel assemblies in the core. There is a high probability that the thermocouples would also indicate any abnormally high coolant temperature rise.

An analysis of the effect of misplacing a fuel assembly was performed on a core very similar to the initial Surry core. The power distribution in the X-Y plane of the core was calculated using a “full core” description with the PDQ-07 code. A discrete representation was used wherein each individual fuel rod was described by a mesh point. The radial power-peaking factor for the reference case (Case 1) was 1.370.

In Case 2, the central fuel assembly which would normally be of 2.15 weight percent enrichment, was assumed to be interchanged with an outer fuel assembly of 3.3 weight percent enrichment. The radial power-peaking factor for this case was 2.538 and occurred in the central fuel assembly. The power distribution was badly skewed with a tilt of approximately 15% across the core. Incore instrumentation would easily detect a misplacement of this nature.

In Case 3, the central 2.15 weight percent enrichment fuel assembly in the core was assumed to be interchanged with a neighboring 2.70 weight percent enrichment fuel assembly. The radial power-peaking factor for this case was 1.625. A power distribution tilt of approximately 10% results in the two rows of fuel adjacent to the interchanged fuel assemblies, which would be detected by the incore instrumentation. The interchange of 2.15 and 2.70 weight percent enrichment fuel assemblies not at the core center would introduce more pronounced power distribution tilts than Case 3.

The possibility of having an assembly in which all the fuel is of the wrong enrichment was also considered. In this case there was no interchange of assemblies, but there was one assembly in the core that departed from the nominal enrichment.

An analysis of the effect of an inadvertent loading of an assembly with an enrichment increased by 20% over the nominal value showed that the error was detectable at many of the detector locations in the core. In the case of a centrally placed assembly with this enrichment error, five flux detectors would show a signal more than 5% above the expected value. If the assembly bearing the enrichment error was placed off-center and as far from a flux detector as possible, the tilt caused by a 20% error in enrichment would be detectable in more than half of the detector locations in the core, either as a flux increase over expected symmetric values or as a flux decrease on the opposite side of the core.

If the movable detector system failed to detect an assembly enrichment error, the peaking factors would still show margin to the design conditions through the inclusion of measurement uncertainties, and normal plant operation could be safely continued. It is not credible that any positive indication of power distribution anomalies that are sufficiently large to cause a significant departure from design conditions would be ignored. These measurements are an integral part of the physics start-up tests where considerable emphasis is placed on obtaining good power distribution measurements.

In the event that a single fuel pin or a single fuel pellet had a higher enrichment than the nominal value, then the local power generation would be increased approximately by the percentage of the enrichment error. In the case of an enrichment error greater than 8% there exists a possibility, depending on location, that design limits on fuel rating would be violated for that pin or pellet. The consequences of such a local reduction of DNBR and increase in clad and fuel temperatures would be limited to the incorrectly loaded pin or pins.

During initial core loading and subsequent refueling operations, detailed written handling and checkoff procedures are utilized throughout the loading sequence. The initial cores were loaded in accordance with a core loading plan similar to that illustrated in Figure 3.5-3, which shows the locations of the different enrichment fuel assemblies typically used in initial cores. The actual core loading plans for both initial and reload cores show the identification number for the fuel assembly used in each core location.

During subsequent refueling operations, reconstituted fuel assemblies (see Section 3.5.2.1) may be included among the fuel assemblies used for reloading the core.

3.5.2.2 **Control Rod Assemblies**

The control rod assemblies each consist of a group of individual control rods fastened at the top end to a common spider assembly. These assemblies, one of which is shown in Figures 3.5-4 and 3.5-12, are provided to control the reactivity of the core under operating conditions. These assemblies contain absorber material for 142 inches of their length. The number of control rod assemblies for the initial cores is specified in Table 3.5-1. Part length rods have since been removed.

The absorber material used in the control rods is silver-indium-cadmium alloy, which is essentially “black” to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of rods, which are sealed in stainless steel tubes to prevent the rods from coming in direct contact with the coolant.

When the control rod assembly has been fully withdrawn, the tip of the control rods remains engaged in the guide thimbles so that alignment between control rods and thimbles is maintained. Since the control rods are long and slender, they are relatively free to conform to any small misalignments encountered with the guide thimble.

The spider assembly is in the form of a center hub with radial vanes containing cylindrical fingers from which the control rods are suspended. Handling detents and detents for connection to the drive shaft are machined into the upper end of the hub. A spring pack is assembled into a skirt integral to the bottom of the hub to stop the control rod assembly and absorb the impact energy at the end of an insertion. The radial vanes are joined to the hub and the fingers joined to the vanes by furnace brazing. A centerpost that holds the spring pack and its retainer is threaded into the hub within the skirt and welded to prevent loosening in service. All components of the spider assembly are made from type 304 stainless steel except for the springs, which are Inconel X-750 alloy, and the retainer, which is 17-4 PH stainless in the H 1100 condition.

The control rods are fastened securely to the spider. The rods are first threaded into the spider fingers, pinned to maintain joint tightness, and the pins are then welded in place. The end plug below the pin position is designed with a reduced section to permit flexing of the rods to correct for small operating or assembly misalignments.

In construction, the silver-indium-cadmium rods are inserted into cold-worked stainless steel tubing which is then sealed at the bottom and the top by welded end plugs. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions and to limit the internal pressure to acceptable levels.

The bottom plugs are made bullet-nosed to reduce the hydraulic drag during a reactor trip and to guide smoothly into the dashpot section of the fuel assembly guide thimbles. The upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

The original control rod assembly design was replaced prior to Surry 1 & 2 Cycle 11 and Cycle 24 with an “enhanced performance” control rod assembly design. The enhanced design is essentially the same as the original with the exception of the cladding tubes which are hard chrome plated to increase both wear resistance and the life of the control rods. The ends of the cladding tubes are not plated, however, to preclude weld contamination of the end plug. Trace element impurities in the cladding were also restricted to lower values than previously allowed to reduce corrosion in the cladding. In addition, the absorber rodlet diameter in the lower twelve inches of the absorber rods was reduced to decrease cladding strain due to swelling induced by irradiation of the absorber.

The chrome plated stainless steel clad silver-indium-cadmium alloy absorber rods are resistant to radiation and thermal damage. thereby ensuring their effectiveness under all operating conditions.

3.5.2.3 **Neutron Source Assemblies**

Two neutron source assemblies were utilized in the initial cores. These assemblies consisted of three secondary source rods and one primary source rod, twelve burnable poison rods and four thimble plugs each. The primary source rods contained capsules of Plutonium-Beryllium source material 24 inches long. The secondary source rods contained Antimony-Beryllium pellets stacked to a height of 121.754 inches. The primary source, secondary source and burnable poison rods utilized 304 SS cladding materials. The rods were fastened to a spider at the top end similar to the control rod spiders. The neutron source rods were inserted, as part of two burnable poison rod assemblies, into the control rod guide thimbles in fuel assemblies at unrodded locations in the core.

For the initial Unit 1 and Unit 2 cores following the steam generator replacement outages (Unit 1 Cycle 6 and Unit 2 Cycle 5), each core contained two new primary source assemblies containing one primary source rod and 12 burnable poison rods each. Each core also contained three secondary source assemblies containing four secondary source rods and sixteen thimble plugs each. The primary source rods contained a 1.5-inch length of Californium-252. Aluminum oxide spacers were used to maintain the source material position in the rod. The secondary source rods contained Sb-Be pellets stacked to a height of 67.87 inches. The primary source, secondary source and burnable poison rods all utilized 304 SS cladding material. The rods on the primary source assemblies were attached to a base plate similar to the standard burnable poison assemblies. The secondary source rods were fastened to a spider at the top end similar to the control rod spiders. The rods in the neutron source assemblies were inserted into the control rod guide thimbles in fuel assemblies at unrodded locations in the core.

The primary sources were used in the initial cycles (and in the first cycles following steam generator replacement) to ensure adequate count rate for the source range detectors at the beginning of cycle. No primary sources are currently placed in reload cycles. Secondary sources were loaded in reload cores through Cycle 14 at each unit, but were removed until Cycle 26 at Unit 2 and Cycle 27 at Unit 1.

Beginning with the aforementioned cycles, secondary source assemblies were re-inserted into the Surry reactor cores. The assemblies have slightly different design than the secondary sources used in prior cycles. Each core holds two secondary source assemblies containing six secondary source rods without thimble plugs. The secondary source rods contain Sb-Be pellets stacked to a height of 88.0 inches and are attached to a base plate similar to standard burnable poison assemblies. All rods utilize a double-encapsulated design with 304 SS cladding material. The neutron sources assemblies will be inserted into the control rod guide thimbles in fuel assemblies at unrodded locations in the core.

Source range detector minimum count rate can be provided by the fuel assemblies on the periphery of the core, and secondary sources are not normally required for this purpose. Secondary sources may be loaded into reload cores to charge them for possible future use.

Design criteria similar to those for the fuel rods were used for the design of the source rods. The requirements for the source rods included that the cladding be free-standing, internal pressures remain less than reactor operating pressure, and sufficient internal gaps and clearances be provided to allow for differential expansions between the source material and cladding.

3.5.2.4 **Plugging Devices**

It is permissible to limit bypass flow through the guide thimbles in fuel assemblies that do not contain insert components such as control rod assemblies, source assemblies, or burnable poison rods, by fitting the fuel assemblies at those locations with plugging devices. The plugging devices consist of a flat retaining plate with short rods suspended from the bottom surface of the plate and a spring pack assembly attached to the top surface. During installation in the core, the plugging devices fit within the fuel assembly top nozzles and rest on the top nozzle adaptor plate. The short rods project into the upper ends of the guide thimbles to reduce the bypass flow area. The spring pack is compressed by the upper core support assembly when it is lowered into place.

All components in the plugging devices, except for the springs, are constructed from type 304 stainless steel. The springs used in each plugging device are wound from an age-hardenable Inconel X-750 to obtain higher strength.

Beginning with Cycle 10 of each unit, all plugging devices were removed from the core (Reference 7).

3.5.2.5 **Burnable Poison Rod Assemblies**

Burnable poison rod assemblies (BPRA) may be incorporated into the core design to reduce the soluble boron requirement for control of excess reactivity, and to shape the core power distribution. The number of BPRA or BPRA poison rods may vary from one operating cycle to the next, and may be used in any fuel assembly not under a control rod bank location. BPRA burnable poison rods are commonly referred to as fixed, discrete, and/or removable burnable poison rods. This type of burnable poison is “fixed” and “discrete” in the sense that the neutron absorber is contained in solid form (not soluble) in discrete rods (separate from the fuel). BPRA burnable poison is removable because the BPRA itself may be removed from the fuel assembly.

The BPRA burnable poison rods consist of $A1_20_3$-B_4C pellets contained within Zircaloy-4 tubular cladding that is plugged and seal-welded at the ends to encapsulate the pellets. The pellets are supported by the bottom end plug and, depending on pellet stack length, spacers may also be employed. A typical BPRA burnable poison rod is shown in Figure 3.5-13.

The BPRA burnable poison rods in each fuel assembly are grouped and attached together at the top end of the rods by a flat retaining plate that fits inside the fuel assembly top nozzle and rests on the top nozzle adaptor plate. The retaining plate and the poison rods are held down and restrained against vertical motion through a spring pack attached to the plate. This spring is compressed by the upper core plate when the reactor upper internals package is lowered into the reactor, and this ensures that the poison rods cannot be lifted out of the core by flow forces. Each rod is attached to the retaining plate.

The clad in the poison rod assemblies is cold-worked Zircaloy-4 seamless tubing. The upper and lower end plugs, nuts and solid spacers are fabricated from Zircaloy-4. The spring spacers are 302 or 304 stainless steel. The hold-down assembly is fabricated from stainless steel similar to type 304, except for the hold-down springs which are wound from Inconel 718 wire.

3.5.2.6 **Evaluation of Core Components**

3.5.2.6.1 Fuel Evaluation

The integrity of the fuel rods is ensured by proper fuel rod design. This is achieved by designing the fuel rods so that specific design criteria are satisfied. The design process must consider the effects of variations and fluctuations in core and local power, and in reactor coolant temperature, pressure and flow which occur during normal operation and Anticipated Operational Occurrences (AOOs).

To ensure reliable operation, established fuel rod design criteria must be satisfied for all operating conditions consistent with normal operation and AOOs. The fuel rod design is judged to have met these criteria when it is demonstrated that the performance of a fuel region is within the limits specified by the criteria for these events. This is generally accomplished by demonstrating that the limiting fuel rod performance with appropriate allowance for uncertainties is within the limits specified by each criterion. These evaluations are performed using the Performance Analysis and Design (PAD5) code and models (Reference 14) which is licensed up to a fuel rod average burn up of the design (i.e., 62,000 MWD/MTU for Surry Improved Fuel Assemblies with ZIRLO High Performance Cladding Material and 15x15 Upgrade assemblies with Optimized ZIRLO High Performance Cladding Material that is consistent with the burnup extension included in References 17 and 20). Note that the older Surry fuel assemblies with Zicaloy-4 cladding remain limited to 60,000 MWD/MTU (Reference 2).

- Clad Stress
  - Design Basis - The fuel system will not be damaged due to excessive fuel clad stress.
  - Acceptance Limit - Maximum cladding stress intensities excluding Pellet-Cladding Interaction (PCI) induced stress shall be evaluated based on American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code guidelines. Stresses in the cladding are combined to calculate a maximum stress intensity which is then compared to the criteria described in Reference 14.
- Clad Strain

- Design Basis - The fuel rod will not fail due to excessive fuel clad strain.
- Acceptance Limit - The design limit for the fuel rod clad strain is that the total tensile strain, elastic plus plastic, due to uniform cylindrical fuel pellet deformation during any single Condition I or II transient shall be less than 1% from the pre-transient value.

- Rod Internal Pressure
  - Design Basis - The fuel system will not be damaged due to excessive fuel rod internal pressure.
  - Acceptance Limit - The internal pressure of the lead fuel rod in the reactor will (1) be limited to a value below that which could cause the diameter gap to increase (cladding liftoff) due to outward cladding creep during normal operation; (2) be limited to a value below that which could result in cladding hydride reorientation in the radial direction; and (3) be limited to preclude extensive Departure from Nucleate Boiling (DNB) propagation.
- Clad Fatigue
  - Design Basis - The fuel system will not be damaged due to fatigue.
  - Acceptance Limit - The fatigue life usage factor is limited to prevent reaching the material fatigue limit.
- Clad Oxidation
  - Design Basis - The fuel system will not be damaged due to excessive fuel clad oxidation.
  - Acceptance Limit - The predicted oxide thickness shall be no greater than 100 microns.
- Clad Hydrogen Pickup
  - Design Basis - The fuel system will be operated to prevent significant degradation of mechanical properties of the clad at low temperatures as a result of hydrogen embrittlement caused by the formation of zirconium hydride platelets.
  - Acceptance Limit - The best estimate hydrogen pickup in the cladding shall not exceed 600 ppm on a volume-average basis at end of life through the entire clad wall.
- Fuel Rod Axial Growth
  - Design Basis - The fuel system will not be damaged due to excessive axial interference between the fuel rods and the fuel assembly structure.
  - Acceptance Limit - The fuel rods shall be designed with adequate clearance between the fuel rod and the top and bottom nozzles to accommodate the differences in the growth of fuel rods and the growth of the assembly without interference.

- Clad Flattening
  - Design Basis - Fuel rod failures will not occur due to clad flattening.
  - Acceptance Limit - The fuel rod design shall preclude clad flattening during projected exposure.
- Clad Free Standing
  - Design Basis - The fuel system will not be damaged due to excessive fuel clad stress.
  - Acceptance Limit - The cladding shall be short-term free standing at beginning of life, at power, and during hot hydrostatic testing.
- Fuel Pellet Overheating (Power-to-Melt)
  - Design Basis - The fuel rods will not fail due to fuel centerline melting for normal operation or AOOs.
  - Acceptance Limit - The fuel rod centerline temperature shall not exceed the fuel melt temperature during Condition I and II operation, accounting for degradation of the melt temperature due to burn up and the addition of integral burnable absorbers.
  - The PAD5 melting temperature model uses the following equation based on an unirradiated UO2 fuel melting point of 5080 °F and burnup.

$$T_{melt} = 5080°F - \frac{9}{10,000}(BU)$$

Where,

T_{melt} = UO_2 melting temperature, °F

BU = UO_2 burnup, MWD/MTU

- Pellet/Clad interaction (PCI)
  - Design Basis - The fuel rod will not fail due to pellet clad interaction.
  - Acceptance Limit -Two related criteria, the one percent clad strain criterion and the fuel overheating criterion, must be met.

Reference 14 is the basis for these fuel performance criteria, which are evaluated on a cycle-specific basis as part of each fuel reload.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The Region 1 fuel was initially expected to be irradiated for only the first cycle of reactor operation, so an initial density of 94% was used for this fuel. Since the Region 2 and 3 fuel was expected to be retained through two and three cycles of operation, respectively, lower fuel pellet densities were specified for these regions to accommodate the anticipated effects of the higher burnups this fuel would reach. The specified initial density was 93% for Region 2, and 92% for Region 3. Reload cores have utilized a slightly higher nominal pellet density. The operation of this fuel to approved burnup levels is supported by the current fuel densification and swelling model, and by operating experience with higher density fuel.

There are no Technical Specification restrictions on fuel residence time. The high-density prepressurized fuel is typically used for two to four cycles of operation. Current Westinghouse fuel is stable with respect to densification, so significant axial pellet column gaps and clad flattening do not occur (Reference 3).

The design bases and functional requirements for the fuel assembly structural components are discussed in References 6, 8, 9, 11, and 14.

3.5.2.6.2 Evaluation of Control Rods

Time of control rod assembly trip and control rod cooling were evaluated as follows:

1. Analytical techniques were used to predict the trip behavior of a control rod assembly. Tests were also performed under an experimental program conducted in the Westinghouse Reactor Evaluation Center, and the results verified these analytical techniques.

   The calculated control rod insertion trip to the dashpot entry at full flow rate and operating temperature is less than the design value.

2. Control rod guide thimble and dashpot flow analyses have been performed to determine the adequacy of thimble design to meet cooling requirements. Results indicated that adequate cooling flow is provided in the dashpot and the thimble to prevent boiling.

3.5.2.6.3 Evaluation of Burnable Poison Rods

The BPRA burnable poison rods are positively positioned in the core inside fuel assembly guide thimbles, and held in place by attachments to an upper structure assembly compressed beneath the upper core plate. In order to maintain encapsulation of the absorber material throughout the design lifetime, the BPRA burnable poison rod design incorporates sufficient margin to accommodate the anticipated effects of gas release, absorber material swelling, clad growth and creep, stress, strain, and corrosion.

The BPRA burnable poison rods consist mainly of a column of poison pellets encapsulated within cold-worked, Zircaloy-4 seamless tubing. The individual pellets are a sintered ceramic of relatively low density $A1_20_3$-B_4C and are in the form of a solid, right circular cylinder with flat ends. Rod fabrication is initiated by loading a spring spacer into the tubing, followed by the poison pellets. The spring spacer is loaded into the plenum gap region of the rod to support the pellet stack for shipping, handling and operation. For operation, the spring preload ensures a bearing load on the pellet stack and individual pellets, such that no axial gaps are available in he rod to allow clad creep collapse. A solid spacer may also be employed depending on the length of the pellet stack.

The assembled BPRA burnable poison rods are prepressurized with dry, high purity helium gas. During operation, the pressurized helium gas provides good heat transfer across the pellet-to-clad diametral gap and reduces the pressure differential across the clad wall thickness which contributes to clad creep ovality. Sufficient volume is provided in the rod plenum gap region, accounting for the reduction in available volume due to the spring spacer, to accommodate the prepressurization gas plus the gas released from the poison due to the neutronic reaction between the B^{10} isotope and thermal neutrons.

Fuel rods containing integral burnable absorber (IFBA) are evaluated as described in Section 3.5.2.6.1. The evaluation also considers the effects of gas that accumulates inside the rod as a result of neutron absorption by the boride burnable absorber material. The same design limits apply to all fuel rods, whether or not the rod contains integral poison.

3.5.2.6.4 Effects of Vibration and Thermal Cycling on Fuel Assemblies

Reactor coolant flow can induce fuel rod vibration. The effect of the vibration on the fuel assembly and individual fuel rods is minimal. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The fuel assembly grids provide sufficient fuel rod support to limit fuel rod vibration and to maintain cladding wear to within acceptable limits. Significant operating experience exists with Westinghouse fuel using the grid designs found in the LOPAR and SIF assemblies. Significant wear of the cladding or grid supports is not expected during the life of the assembly, nor have grid or fuel rod abnormalities been observed on this fuel.

The effect of thermal cycling of the fuel on the grid to rod support is a slight relative movement between the grid contact surfaces and the clad. This movement is gradual during heatup and cooldown, and the grid assemblies allow thermal expansion of the rods without imposing restraint sufficient to develop buckling or distortion of the fuel rods. The number of such thermal cycles is small over the life of a fuel assembly, so this motion is a negligible contribution to wear of the contacting parts.

The deflection of the control rods, or rods of fuel insert components such as burnable poison rods, flux suppression inserts (Unit 1 only, Cycles 13 through 20), thimble plugs or source rods, is limited by the fit within the fuel assembly guide thimbles. Analyses performed for the original core insert components indicate that cyclic deflections within the limited range allowed by the guide thimbles results in an insignificantly low stress in either the insert rodlets or in the joint of the rodlet to a spider or retainer plate.

3.5.3 Control Rod Drive Mechanism

3.5.3.1 Control Rod Assembly Design Description

The control rod drive mechanisms are used for withdrawal and insertion of the control rod assemblies in the reactor core, and to provide sufficient holding power for stationary support.

Fast total insertion, or reactor trip, is obtained by simply removing the electrical power to allow the control rod assemblies to fall by gravity.

The complete drive mechanism, shown in Figure 3.5-14, consists of the internal latch assembly, the pressure vessel, the operating coil stack, and the drive shaft assembly.

Each assembly is an independent unit that can be dismantled, removed, or installed separately. Each drive mechanism is threaded and seal-welded onto an adaptor located on top of the reactor pressure vessel, and is connected to the control rod assembly directly below by means of a grooved drive shaft. The upper section of the drive shaft is suspended from the working components of the drive mechanism. The drive shaft and control rod assembly remain connected during all reactor operations, including trip of the control rod assemblies.

Reactor coolant fills the pressure-containing parts of the drive mechanism. All working components and the shaft are immersed in the reactor coolant, and utilize it for cooling and lubrication of sliding parts.

Three magnetic coils, which form a removable electrical unit and surround the control rod drive mechanism pressure housing, induce magnetic flux through the housing wall to operate the working components. They move two sets of latches that lift or lower the grooved drive shaft.

The three magnets are turned on and off in a fixed sequence by solid-state switches. The sequencing of the magnets produces step motion over the 144 inches of normal control rod travel.

The mechanism is capable of handling a 360-lb load, including the drive rod weight, at a rate of 45 inches per minute. Lift capacity is available for overcoming mechanical friction between the moving and the stationary parts. Gravity provides the drive force for control rod assembly insertion and the weight of the whole control rod assembly is available to overcome any resistance.

The mechanisms are designed to operate in water at 650°F and 2485 psig. The temperature at the mechanism head adaptor is much less than 650°F because it is located in a region of limited water flow from the reactor core.

A multiconductor cable connects the mechanism operating coils to the dc power supply through the power programmer. The power supply is described in Section 7.3.

All part-length control rod assemblies have been removed. On Unit 1, the part-length control rod drive mechanisms have been removed from all core locations except H04. The mechanism housing at location H04 is used for the reactor vessel head vent system. On Unit 2 all the part-length control rod drive mechanisms have been removed and a direct penetration in the reactor vessel head is used for the reactor vessel head vent system. To maintain the pressure boundary function, adapter plugs were threaded on the part-length locations and then seal welded with a canopy weld. To maintain cooling airflow characteristics, dummy cans were attached to the adapter plugs to occupy the volume of the removed part-length control rod drive mechanisms.

3.5.3.1.1 Latch Assembly

The latch assembly contains the working components that withdraw and insert the drive shaft and attached control rod assembly. It is located within the pressure housing and consists of the pole pieces of three electromagnets. They actuate two sets of latches that engage the grooved section of the drive shaft.

The upper set of latches move up or down to raise or lower the drive rod by 0.625 inch. The lower set of latches have a 0.047-inch axial movement to shift the weight of the control rod assembly from the upper to the lower latches.

3.5.3.1.2 Pressure Vessel

The pressure vessel consists of the latch housing and the rod travel housing. The latch housing is the lower portion of the vessel, and contains the latch assembly. The rod travel housing is the upper portion of the vessel. It provides spaces for the drive shaft during its movement.

The housings are designed in accordance with the requirements for Class A vessels of ASME Code Section III, Nuclear Vessels.

3.5.3.1.3 Operating Coil Stack

The operating coil stack is an independent unit that is installed on the drive mechanism by sliding it over the outside of the pressure housing. It rests on a pressure housing flange without any mechanical attachment, and may be removed and installed while the reactor is pressurized.

The three operating coils (A, B, and C) are made of round copper wire insulated with a double layer of filament-type glass yarn.

The design operating temperature of the coils is 450°F. Coil temperature can be determined by resistance measurement. Forced air cooling along the outside of the coil stack maintains a coil temperature of approximately 390°F.

3.5.3.1.4 Drive Shaft Assembly

The main function of the drive shaft is to connect the control rod assembly to the mechanism latches. Grooves for engagement and lifting by the latches are located throughout the 144 inches of control rod travel. The grooves are spaced 0.625 inch apart to coincide with the mechanism step length, and have a 45-degree slot angle.

The drive shaft is attached to the control rod assembly by a coupling. The coupling has two flexible arms that engage the grooves in the spider assembly.

A 0.25-inch-diameter disconnect rod runs down the inside of the drive shaft. It utilizes a locking button at its lower end to lock the coupling and control rod assembly. At its upper end, there is a disconnect assembly for remote disconnection of the drive shaft assembly from the control rod assembly.

During unit operation, the drive shaft assembly remains connected to the control rod assembly at all times.

3.5.3.1.5 Position Indicator Coil Stack

The position indicator coil stack slides over the rod travel housing section of the pressure vessel. It detects drive shaft position by means of a cylindrically wound differential transformer that spans the normal length of control rod travel (144 inches).

3.5.3.1.6 Drive Mechanism Materials

All parts exposed to reactor coolant, such as the pressure vessel, latch assembly, and drive rod, are made of metals that resist the corrosive action of the water.

Three types of metals are used exclusively: stainless steel, Inconel X, and cobalt-based alloys. Wherever magnetic flux is carried by parts exposed to the main coolant, stainless steel is used. Cobalt-based alloys are used for the pins, latch arm tips, and pin shoe facing in the latch arms.

Inconel X is used for the springs of both latch assemblies, and type 304 (Unit 1) and type 316 (Unit 2) stainless steel is used for all pressure containment. Hard chrome plating provides wear-resistant surfaces on the sliding parts, and prevents galling between mating parts during assembly.

Outside of the pressure vessel, where the metals are exposed only to the reactor containment environment and cannot contaminate the reactor coolant, carbon and stainless steels are used.

Carbon steel, because of its high permeability, is used for magnetic flux return paths around the operating coils, and is zinc-plated 0.001-inch thick to prevent corrosion.

3.5.3.2 Principles of Operation

The drive mechanism shown schematically in Figure 3.5-14 withdraws and inserts its control rod assembly as electrical pulses are received by the operator coils.

An ON and OFF sequence that is repeated by a silicon-controlled rectifier in the power programmer causes either withdrawal or insertion of the control rod assembly. Position of the control rod assembly is indicated by the differential transformer action of the position indicator coil stack surrounding the rod travel housing. The differential transformer output changes as the top of the ferromagnetic drive shaft assembly moves up within the rod travel housing.

In normal operation, the stationary gripper coil of the drive mechanism holds the control rod assembly withdrawn from the core in a static position until the movable gripper coil is energized.

3.5.3.2.1 Control Rod Assembly Withdrawal

The control rod assembly is withdrawn by repetition of the following sequence of events:

1. Movable Gripper - ON

   The movable gripper armature raises and swings the movable gripper latches into the drive shaft groove.

2. Stationary Gripper Coil - OFF

   Gravity causes the stationary gripper latches and armature to move downward until the load of the drive shaft is transferred to the movable gripper latches. Simultaneously, the stationary gripper latches swing out of the shaft groove.

3. Lift Coil - ON

   The 0.625-inch gap between the lift armature and the lift magnet pole closes, and the drive rod raises one step length.

4. Stationary Gripper Coil - ON

   The stationary gripper raises and closes the gap below the stationary gripper magnetic pole, and swings the stationary gripper latches into a drive shaft groove. The latches contact the shaft and lift it 0.047 inch. The load is thus transferred from the movable to the stationary gripper latches.

5. Movable Gripper Coil - OFF

   The movable gripper armature separates from the lift armature under the force of one spring and gravity. Three links, pinned to the movable gripper armature, swing the three movable gripper latches out of the groove.

6. Lift Coil - OFF

   The gap between the lift armature and the lift magnet pole opens. The movable gripper latches drop 0.625 inch to a position adjacent to the next groove.

3.5.3.2.2 Control Rod Assembly Insertion

The sequence for control rod assembly insertion is similar to that for control rod assembly withdrawal:

1. Lift Coil - ON

   The movable gripper latches are raised to a position adjacent to a shaft groove.

2. Movable Gripper Coil - ON

   The movable gripper armature raises and swings the movable gripper latches into a groove.

3. Stationary Gripper Coil - OFF

   The stationary gripper armature moves downward and swings the stationary gripper latches out of the groove.

4. Lift Coil - OFF

   Gravity separates the lift armature from the lift magnet pole, and the control rod assembly drops down 0.625 inch.

5. Stationary Gripper Coil - ON

   See Section 3.5.3.2.1, event number 4.

6. Movable Gripper Coil - OFF

   See Section 3.5.3.2.1, event number 5.

The sequences described above are considered to be one step or one cycle, and the control rod moves 0.625 inch for each cycle. Each sequence can be repeated at a rate of up to 72 steps per minute, and the control rods can therefore be withdrawn or inserted at a rate of up to 45 in/min. Tripping by gravity is not subject to the rate limit of 45 in/min.

3.5.3.2.3 Control Rod Assembly Tripping

If power to the stationary gripper coil is cut off, as it is for tripping, the combined weight of the drive shaft and the control rod assembly is sufficient to move the latches out of the shaft groove. The control rod assembly falls by gravity into the core. The tripping occurs as the magnetic field, holding the stationary gripper armature against the stationary magnet, collapses, and the stationary gripper armature is forced down by the weight acting upon the latches.

3.5.4 Fuel Assembly and Control Rod Assembly Mechanical Tests

To prove the mechanical adequacy of the fuel assembly and control rod assembly, functional test programs were conducted on three test assemblies representative of the Surry LOPAR design. One test was run on a full-scale San Onofre (Reference 4) mock-up version of the fuel assembly and control rod assembly, and the other two on two full-scale assemblies for a 12-foot active core. One of the 12-foot assemblies incorporated stainless steel guide tubes, and the other incorporated Zircaloy-4 guide tubes. These tests were performed with silver-indium-cadmium control rods.

The test assemblies were tested under simulated reactor operating conditions at 1800 psig, 575°F, and flow velocities up to 16.5 ft/sec in the Westinghouse Reactor Evaluation Center for a total of more than 6400 hours.

Each test assembly was subjected to trip cycling equivalent to one or more station lifetimes. The test history for each prototype is summarized in Table 3.5-2.

Each of three test fuel assemblies remained in excellent mechanical condition. No measurable signs of wear on the fuel tubes or control rod guide thimbles were found.

The control rods were also found to be in excellent condition, with maximum wear on absorber cladding measuring approximately 0.001 inch.

3.5.4.1 **Loading and Handling Tests**

Tests simulating the loading of the test fuel assemblies into a core location were conducted to determine that proper provisions were made for guidance of a fuel assembly during refueling operations. A dummy fuel assembly is still used to test operability of fuel movement equipment.

3.5.4.2 **Lateral and Axial Bending Tests**

3.5.4.2.1 Lateral Bending Tests

A prototype fuel assembly was subjected to lateral bending tests in order to determine the mechanical characteristics of the assembly, and to verify that it was capable of withstanding the loads and deflections that would be encountered during shipping, handling, and core operation. The lateral bending tests showed than an assembly is capable of withstanding lateral deflections in excess of 0.25 inch at mid-height when supported as in the core, and in excess of 0.5 inch at the top nozzle when standing free, without evidence of damage. Deflections encountered during shipment and core operation, and specified allowable (and normally expected) deflections during handling and storage, do not exceed these limits.

3.5.4.2.2 Axial Load Test

In axial tests, the prototype assembly was successfully loaded to 2200 lb or more with no resulting damage. The maximum column load expected to be experienced in service is 1000 lb.

The test results have been used as a reference in the design of fuel-handling equipment to establish the limits for inadvertent axial loads during refueling.

3.5 REFERENCES

1. Westinghouse Electric Corporation, *Irradiation of 17 x 17 Demonstration Assemblies in Surry Units No. 1 and 2*, *Cycle 2*, WCAP-8362, July 1974.

2. B. C. Buckley and L.B. Engle (NRC) to W.L. Stewart (Virginia Electric and Power Company), *Surry, Units 1 and 2, and North Anna, Units 1 and 2—Removal of 45,000 MWD/MTU Batch Average Burnup Restriction (TAC Nos. M87767, M87768, M87812, and M87813)*, letters dated December 14, 1993 and April 20, 1994.

3. S. L. Davidson, R. L. Oelrich, and P. J. Kersting, *Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel,* WCAP-13589-A, March 1995.

4. *Large Closed Cycle Water Reactor Research and Development Program,* Quarterly Progress Reports for the period January 1963 through June 1965, WCAP-3738, 3739, 3743, 3750, 3269-2, 3269-3, 3269-5, 3269-6, 3269-12, and 3269-13.

5. J. D. Neighbors (NRC) to W. L. Stewart (Virginia Electric and Power Company), Transmittal of Amendment 102 with Safety Evaluation, Serial No. 85-649, dated August 1985.

6. Davidson, *Reference Core Report—Vantage 5 Fuel Assembly,* Westinghouse Report WCAP-10444-P-A, dated September 1985.

7. W. L. Stewart (Virginia Power) to U. S. Nuclear Regulatory Commission, Subject; *Proposed Technical Specifications Change Surry Improved Fuel Assembly,* Serial No. 87-188, May 26, 1987.

8. S. L. Davidson and T.L. Ryan, *VANTAGE+ Fuel Assembly Reference Core Report,* WCAP-12610-P-A (Proprietary), April 1995.

9. *Addendum 1 to WCAP-12488-A, Revision to Design Criteria,* WCAP-12488-A, Addendum 1-A, Revision 1 (Proprietary), January 2002.

10. Letter from S.P. Lingam (NRC) to D.A. Christian (Dominion), "*Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Increase in the Lead Rod Average Burnup Limit (TAC Nos. MD4716 and MD4717),*" Serial No. 07-0854, December 19, 2007.

11. H. H. Shah and P. Schueren, *Optimized ZIRLO,* WCAP-12610-P-A and CENPD-404-P-A, Addendum 1-A (Proprietary), July 2006.

12. Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding the Use of Optimized ZIRLO™ Fuel Rod Cladding (TAC Nos. ME3343 and ME3344)*, Serial No. 10-669, December 22, 2010; as amended by Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Corrections to Amendments Regarding the Use of Optimized ZIRLO™ Fuel Rod Cladding (TAC Nos. ME3343 and ME3344)*, Serial No. 10-755, December 23, 2010.

13. R. Lenahan et al., *Westinghouse Clad Corrosion Model for ZIRLO and Optimized ZIRLO*, WCAP-12610-P-A and CENPD-404-P-A, Addendum 2-A, (Proprietary), October 2013.

14. Linsuain, 0., et al., *Westinghouse Performance Analysis and Design Model (PAD5)*, WCAP-17642-P-A, Revision 1, November 2017.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 3.5-1

CORE MECHANICAL DESIGN PARAMETERS[a] (INITIAL CORE)

Parameter	Value
Active portion of the core	
Equivalent diameter	119.7 in.
Active fuel height	144 in.
Length-to-diameter ratio	1.202
Total cross-section area	78.3 ft^2
Fuel assemblies	
Number	157
Rod array	15 x 15
Rods per assembly	204[b]
Rod pitch	0.563 in.
Overall dimensions	8.426 × 8.426 in.
Fuel weight (as UO_2)	175,600 lb
Total weight	226,200 lb
Number of grids per assembly	7
Fuel rods	
Number	32,028
Outside diameter	0.422 in.
Diameter, gap: Regions 1 and 2	0.0075 in.
Region 3	0.0085 in.
Clad thickness	0.0243 in.
Clad material	Zircaloy-4
Fuel pellets	
Material	UO_2 sintered
Density of the first core loading	
Region 1 (inner)	94 (% theoretical)
Region 2 (inner)	93 (% theoretical)
Region 3 (outer)	92 (% theoretical)
Fuel enrichments of first core loading	
Region 1 (inner)	1.85 (wt.%)
Region 2 (inner)	2.55 (wt.%)
Region 3 (outer)	3.10 (wt.%)

a. All dimensions are for cold conditions.
b. Twenty-one fuel rods are omitted: 20 guide thimbles are provided to provide passage for control rods, and one is provided to contain incore instrumentation.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 3.5-1 (CONTINUED)

CORE MECHANICAL DESIGN PARAMETERS[a] (INITIAL CORE)

Parameter	Value
Fuel pellets (continued)	
Fuel enrichments of first core loading (continued)	
Equilibrium regions	3.20 (wt.%)
Diameter: Regions 1 and 2	0.3659 in.
Region 3	0.3649 in.
Length	0.600 in.
Control rod assemblies	
Neutron absorber	Ag-In-Cd
Cladding material	SS 304, cold-worked
Clad thickness	0.024 in.
Number of assemblies	53
Full length	48
Part length	5
Number of control rods per assembly	20
Core structure	
Core barrel	
i.d.	133.9 in.
o.d.	137.9 in.
Thermal shield	
i.d.	142.6 in.
o.d.	148.0 in.
Burnable poison rods	
Number	816
Number of rods per assembly	12
Number of assemblies	68
Material	Borosilicate glass
Outside diameter	0.4395 in.
Inner tube, o.d.	0.2365 in.
Clad material	SS 304
Inner tube material	SS 304
Boron loading (natural)	0.0429 gm/cm of glass rod

a. All dimensions are for cold conditions.

b. Twenty-one fuel rods are omitted: 20 guide thimbles are provided to provide passage for control rods, and one is provided to contain incore instrumentation.

Table 3.5-2
FUEL ASSEMBLY AND CONTROL ROD ASSEMBLY TEST HISTORY

Test	Test Time, hr	Number of Trips	Total Linear Travel, ft	Total Driven Travel, ft	Total Trip Travel, ft
San Onofre, 10-foot assembly, stainless steel guide thimbles	4132	1461	38,927	27,217	11,710
12-foot assembly, stainless steel guide thimbles	1000	600	45,000	38,500	6500
12-foot assembly, Zircaloy-4 guide thimbles	1277	600	124,200	117,700	6500

Table 3.5-3

COMPARISON OF LOPAR, SIF, AND 15 x 15 UPGRADE ASSEMBLY NOMINAL DESIGN PARAMETERS

Parameter	15 x 15 LOPAR Design	15 x 15 SIF Design	15 x 15 Upgrade
Fuel Assembly Length	159.710 in.	159.975 in. (Zircaloy) 159.775 to 159.975 in. (ZIRLO) [a]	159.975 in. (ZIRLO)
Fuel Rod Length	151.85 in.	152.17 to 152.185 in. (Zircaloy) [b] 152.680 to 152.880 in. (ZIRLO) [a]	152.880 in. (Opt. ZIRLO[f])
Assembly Envelope	8.426 in.	8.426 in.	8.426 in.
Compatible with Core Internals	Yes	Yes	Yes
Fuel Rod Pitch	0.563 in.	0.563 in.	0.563 in.
Number of Fuel Rods/Assembly [c]	204	204	204
Number of Guide Thimbles/Assembly	20	20	20
Number of Instrumentation Tubes/Assembly	1	1	1
Compatible w/Movable In-core Detector System	Yes	Yes	Yes
Fuel Tube Material	Zircaloy-4	Zircaloy-4 or ZIRLO [a]	Opt. ZIRLO[f]
Fuel Rod Clad o.d.	0.422 in.	0.422 in.	0.422 in.
Fuel Rod Clad Thickness	0.0243 in.	0.0243 in.	0.0243 in.

a. ZIRLO was introduced on Batch 16 fuel (Cycle 14). The increased ZIRLO fuel assembly and fuel rod lengths were introduced with Surry 2 Batch 20 fuel.
b. Original SIF fuel rods (Batch 12, introduced in Cycle 10) were 152.185 inches long. Length was decreased slightly starting with Batch 13 (Cycle 11) as part of Westinghouse standardization of 15 x 15 fuel products.
c. Reconstituted fuel assemblies may contain some solid metal filler rods in place of fuel rods.
d. Debris filter bottom nozzles were introduced on Batch 13 fuel. P-grids were introduced on Batch 15 fuel (Cycle 13).
e. Starting with Batch 23 (Cycle 21) annular pellets may be used in the top and bottom of fuel rods containing IFBA. The specified diameter does not include the thickness of any IFBA coating that may be used.
f. Fuel assemblies from Surry 1 Batch 27 and Surry 2 Batch 26 and subsequent batches are of the 15 x 15 Upgrade design with Optimized ZIRLO and IFMs.
g. Dimension is for outer tube in tube-in-tube design.
h. Westinghouse Integral Nozzle (WIN) design was introduced on Batch 29 fuel.
i. Advanced Debris Filter Bottom Nozzles (ADFBN) were introduced on Batch 33 fuel.
j. Starting in Surry Unit 2 Batch 33 (Cycle 31), all fuel rods may contain natural or slightly enriched fuel pellets in the top and bottom.

Table 3.5-3 (CONTINUED)
COMPARISON OF LOPAR, SIF, AND 15 x 15 UPGRADE ASSEMBLY NOMINAL DESIGN PARAMETERS

Parameter	15 x 15 LOPAR Design	15 x 15 SIF Design	15 x 15 Upgrade
Fuel/Clad Gap	7.5 mil	7.5 mil	7.5 mil
Fuel Pellet Diameter	0.3659 in.	0.3659 in. [e]	0.3659 in.[j]
Guide Thimble Material	Zircaloy-4	Zircaloy-4 or ZIRLO [a]	ZIRLO
Guide Thimble o.d. above dashpot	0.546 in.	0.533 in.	0.533 in.
Guide Thimble Wall Thickness	0.017 in.	0.017 in.	0.017 in. [g]
Structural Material - Five Inner Grids	Inconel	Zircaloy-4 or ZIRLO [a]	ZIRLO
Structural Material - Two End Grids	Inconel	Inconel	Inconel
Intermediate Flow Mixing Grids [f]			ZIRLO
Grid Inner Strap Thickness	13.5 mil (Inconel Grid)	26 mil (Zircaloy-4 or ZIRLO Grid) [a] 13.5 mil (Inconel) 10.5 mil (P-grid) [d]	22 mil (ZIRLO grid) 13.5 mil (Inconel) 10.5 mil (P-grid) 18 mil (IFM) [f]
Grid Outer Strap Thickness	20.5 mil (Inconel Grid)	32 mil (Zircaloy-4 or ZIRLO Grid) [a] 20.5 mil (Inconel, P-grid) [d]	32 mil (ZIRLO Grid) 20.5 mil (Inconel, P-grid) 26 mil (IFM) [f]

a. ZIRLO was introduced on Batch 16 fuel (Cycle 14). The increased ZIRLO fuel assembly and fuel rod lengths were introduced with Surry 2 Batch 20 fuel.
b. Original SIF fuel rods (Batch 12, introduced in Cycle 10) were 152.185 inches long. Length was decreased slightly starting with Batch 13 (Cycle 11) as part of Westinghouse standardization of 15 x 15 fuel products.
c. Reconstituted fuel assemblies may contain some solid metal filler rods in place of fuel rods.
d. Debris filter bottom nozzles were introduced on Batch 13 fuel. P-grids were introduced on Batch 15 fuel (Cycle 13).
e. Starting with Batch 23 (Cycle 21) annular pellets may be used in the top and bottom of fuel rods containing IFBA. The specified diameter does not include the thickness of any IFBA coating that may be used.
f. Fuel assemblies from Surry 1 Batch 27 and Surry 2 Batch 26 and subsequent batches are of the 15 x 15 Upgrade design with Optimized ZIRLO and IFMs.
g. Dimension is for outer tube in tube-in-tube design.
h. Westinghouse Integral Nozzle (WIN) design was introduced on Batch 29 fuel.
i. Advanced Debris Filter Bottom Nozzles (ADFBN) were introduced on Batch 33 fuel.
j. Starting in Surry Unit 2 Batch 33 (Cycle 31), all fuel rods may contain natural or slightly enriched fuel pellets in the top and bottom.

Table 3.5-3 (CONTINUED)

COMPARISON OF LOPAR, SIF, AND 15 x 15 UPGRADE ASSEMBLY NOMINAL DESIGN PARAMETERS

Parameter	15 x 15 LOPAR Design	15 x 15 SIF Design	15 x 15 Upgrade
Grid Support for Fuel Rods			
(Structural Grids)	6 points 2 springs, 4 dimples	6 points: 2 springs, 4 dimples	6 points: 2 springs, 4 dimples
(P-grid)[d]		4 points: 4 dimples	4 points: 4 dimples
Grid Inner Strap Height, less vanes			
(Inner Grids)	1.50 in.	2.25 in.	1.90 in.
(End Grids)	1.50 in.	1.522 in.	1.522 in.
(P-grid) [d]		0.690 in.	0.690 in.
(IFM) [f]			0.875 in.
Grid Fabrication Method	Brazed joining of interlocking straps	Welded joining of interlocking straps (Inner Grids, P-grid) [d] Brazed joining of interlocking straps (End Grids)	Welded joining of interlocking straps (Inner Grids, IFMs, P-grids) Brazed joining of interlocking straps (End Grids)

a. ZIRLO was introduced on Batch 16 fuel (Cycle 14). The increased ZIRLO fuel assembly and fuel rod lengths were introduced with Surry 2 Batch 20 fuel.
b. Original SIF fuel rods (Batch 12, introduced in Cycle 10) were 152.185 inches long. Length was decreased slightly starting with Batch 13 (Cycle 11) as part of Westinghouse standardization of 15 x 15 fuel products.
c. Reconstituted fuel assemblies may contain some solid metal filler rods in place of fuel rods.
d. Debris filter bottom nozzles were introduced on Batch 13 fuel. P-grids were introduced on Batch 15 fuel (Cycle 13).
e. Starting with Batch 23 (Cycle 21) annular pellets may be used in the top and bottom of fuel rods containing IFBA. The specified diameter does not include the thickness of any IFBA coating that may be used.
f. Fuel assemblies from Surry 1 Batch 27 and Surry 2 Batch 26 and subsequent batches are of the 15 x 15 Upgrade design with Optimized ZIRLO and IFMs.
g. Dimension is for outer tube in tube-in-tube design.
h. Westinghouse Integral Nozzle (WIN) design was introduced on Batch 29 fuel.
i. Advanced Debris Filter Bottom Nozzles (ADFBN) were introduced on Batch 33 fuel.
j. Starting in Surry Unit 2 Batch 33 (Cycle 31), all fuel rods may contain natural or slightly enriched fuel pellets in the top and bottom.

Table 3.5-3 (CONTINUED)

COMPARISON OF LOPAR, SIF, AND 15 x 15 UPGRADE ASSEMBLY NOMINAL DESIGN PARAMETERS

Parameter	15 x 15 LOPAR Design	15 x 15 SIF Design	15 x 15 Upgrade
Grid/Guide Thimble Attachment	Thimbles bulged together with sleeves prebrazed onto grid straps	Thimbles bulged together with sleeves prewelded to grid straps	Thimbles bulged together with sleeves prewelded to grid straps
Top Nozzle	Non-removable	Removable	Removable [h]
Top Nozzle Holddown Springs	1- or 2-leaf	3-leaf	3-leaf
Compatible with Fuel Handling Equipment	Yes	Yes	Yes
Bottom Nozzle	Reconstitutable	Reconstitutable, Debris Filter [d]	Reconstitutable, Debris Filter[i]

a. ZIRLO was introduced on Batch 16 fuel (Cycle 14). The increased ZIRLO fuel assembly and fuel rod lengths were introduced with Surry 2 Batch 20 fuel.
b. Original SIF fuel rods (Batch 12, introduced in Cycle 10) were 152.185 inches long. Length was decreased slightly starting with Batch 13 (Cycle 11) as part of Westinghouse standardization of 15 x 15 fuel products.
c. Reconstituted fuel assemblies may contain some solid metal filler rods in place of fuel rods.
d. Debris filter bottom nozzles were introduced on Batch 13 fuel. P-grids were introduced on Batch 15 fuel (Cycle 13).
e. Starting with Batch 23 (Cycle 21) annular pellets may be used in the top and bottom of fuel rods containing IFBA. The specified diameter does not include the thickness of any IFBA coating that may be used.
f. Fuel assemblies from Surry 1 Batch 27 and Surry 2 Batch 26 and subsequent batches are of the 15 x 15 Upgrade design with Optimized ZIRLO and IFMs.
g. Dimension is for outer tube in tube-in-tube design.
h. Westinghouse Integral Nozzle (WIN) design was introduced on Batch 29 fuel.
i. Advanced Debris Filter Bottom Nozzles (ADFBN) were introduced on Batch 33 fuel.
j. Starting in Surry Unit 2 Batch 33 (Cycle 31), all fuel rods may contain natural or slightly enriched fuel pellets in the top and bottom.

Figure 3.5-1
CORE CROSS SECTION

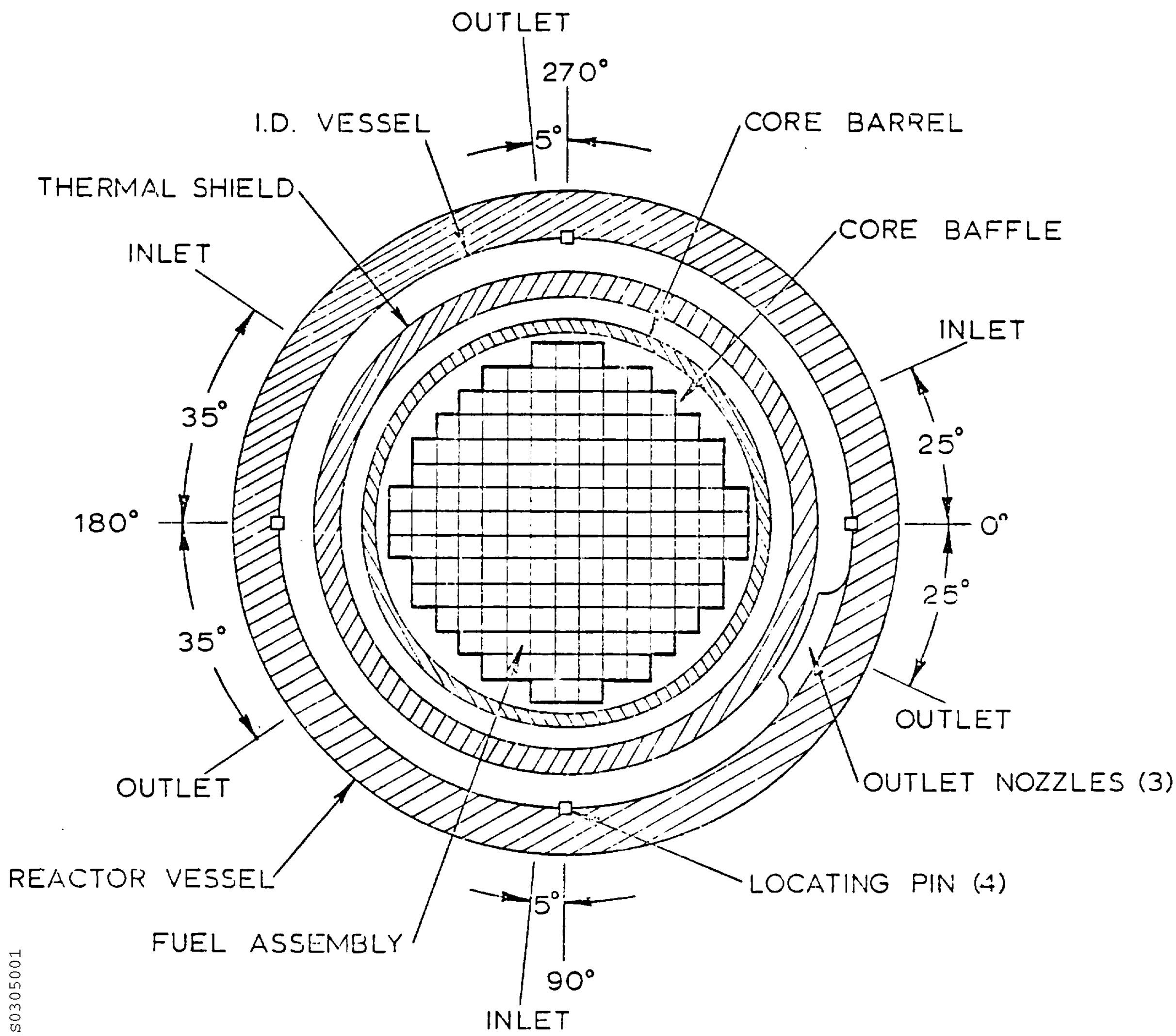


Figure 3.5-2
TYPICAL REACTOR VESSEL AND INTERNALS

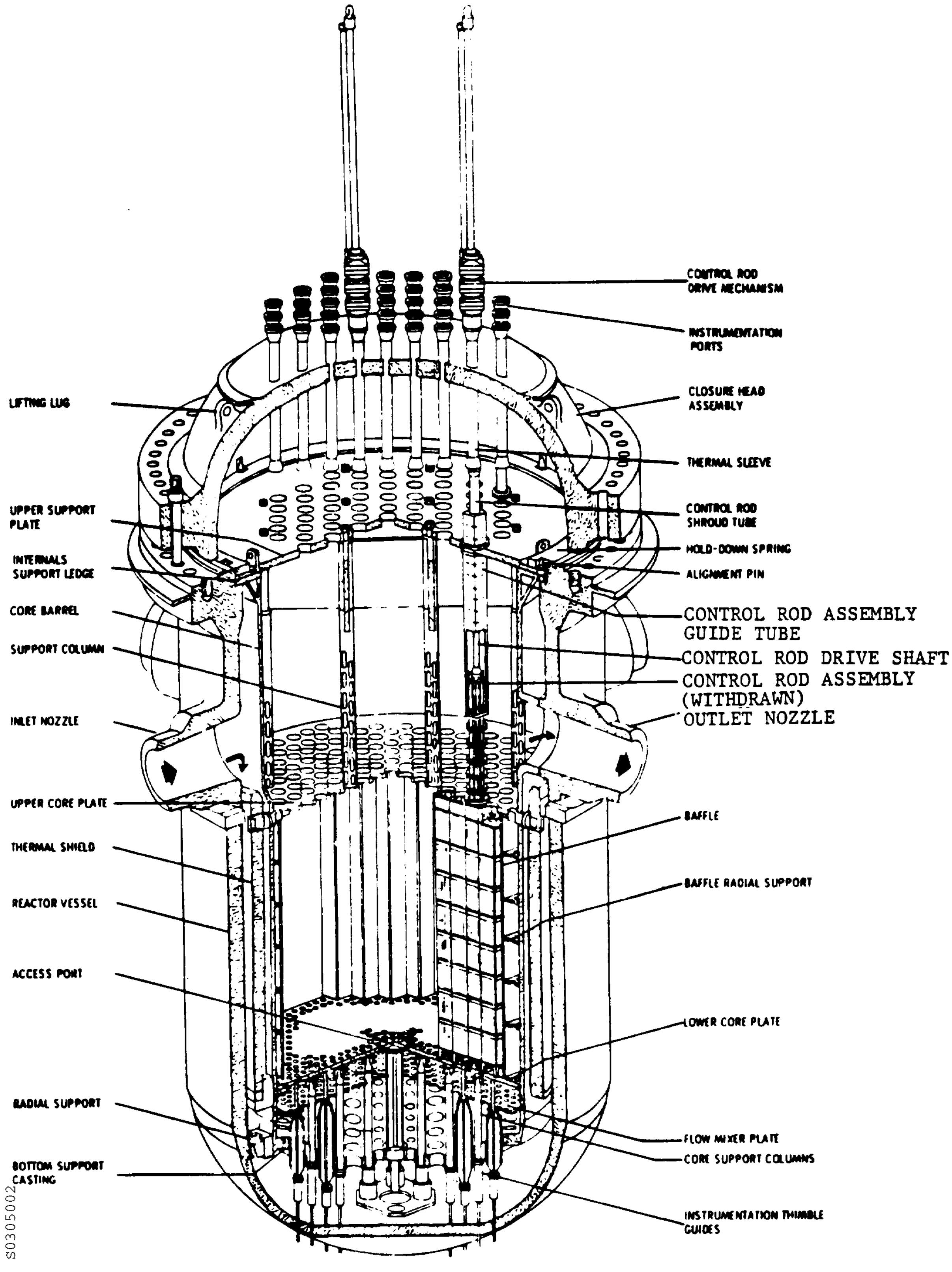
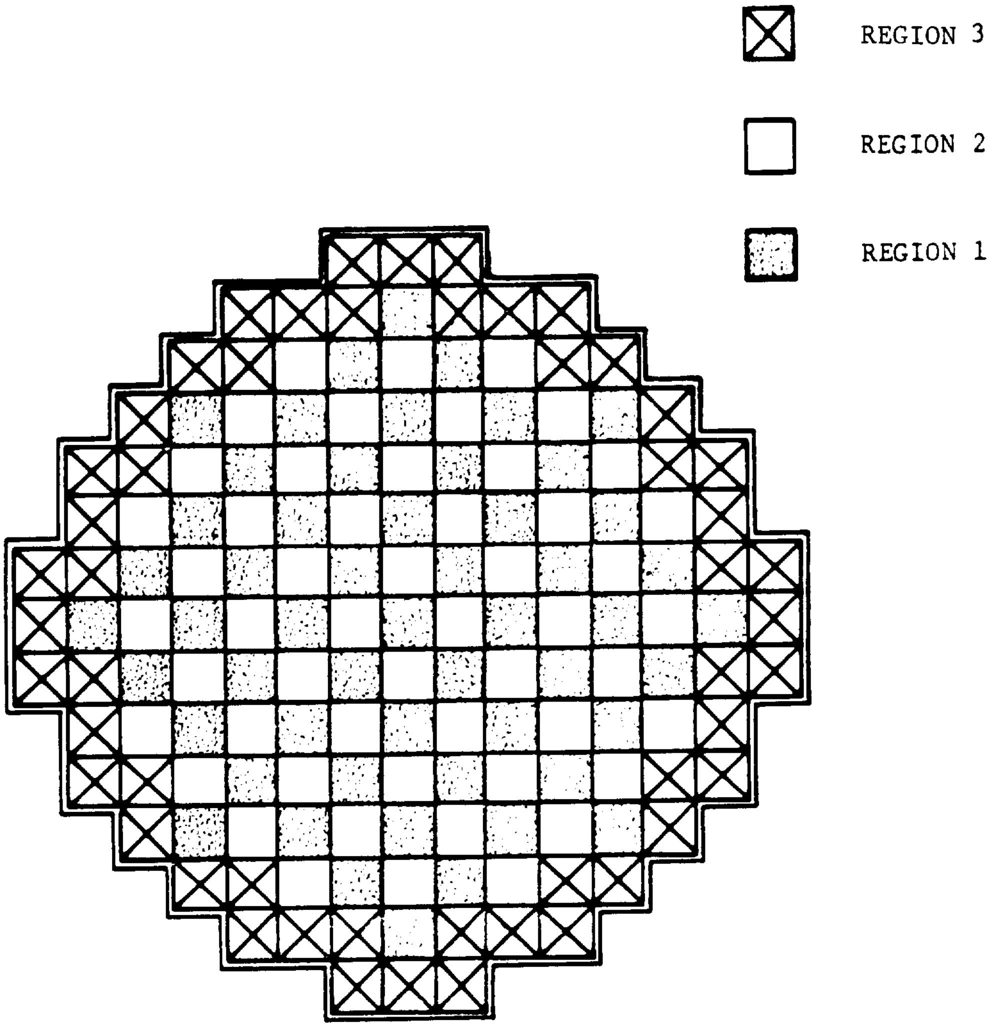


Figure 3.5-3
INITIAL CORE LOADING ARRANGEMENT



305003

Figure 3.5-4
TYPICAL LOPAR FUEL ASSEMBLY WITH CONTROL ROD

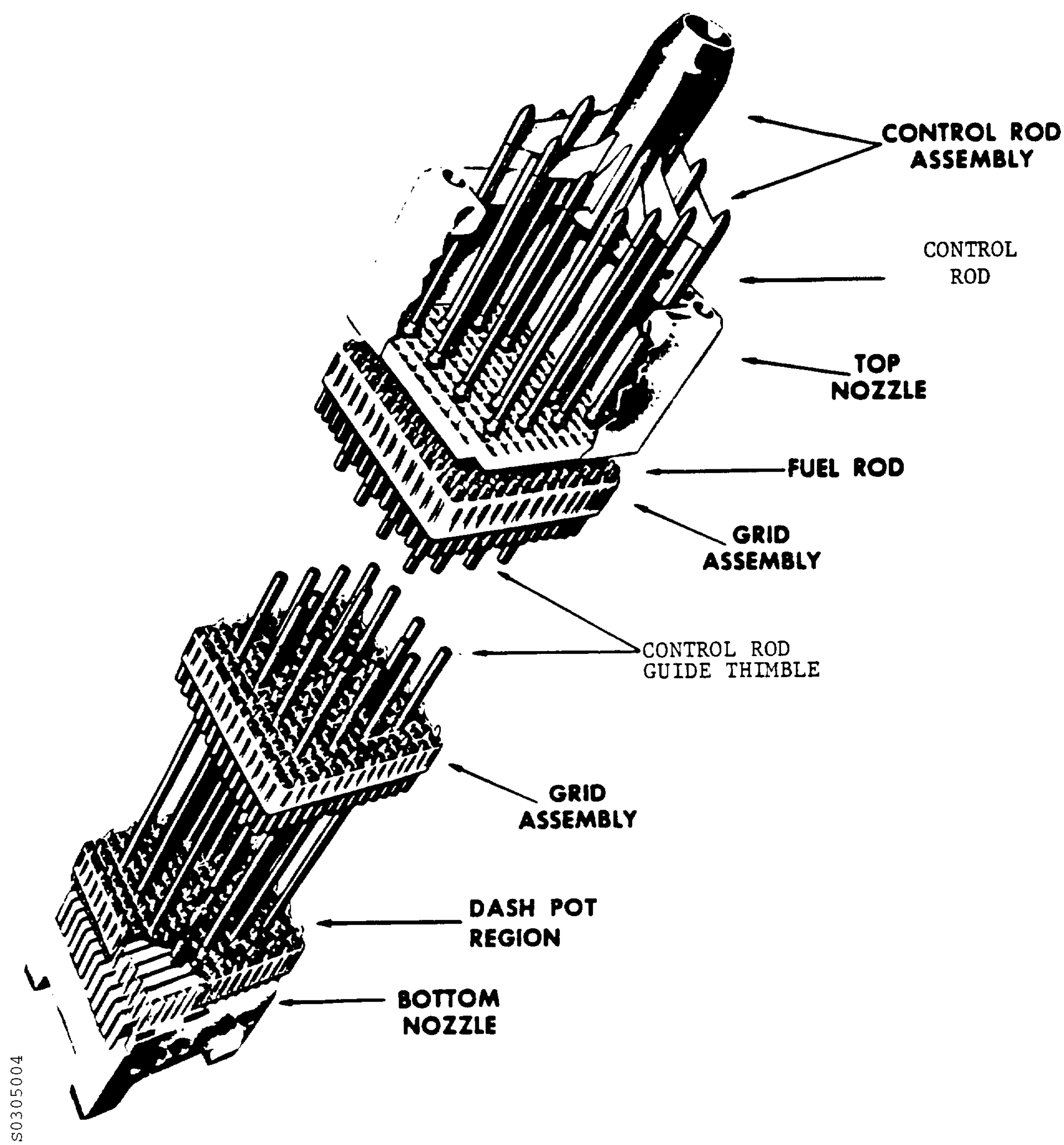
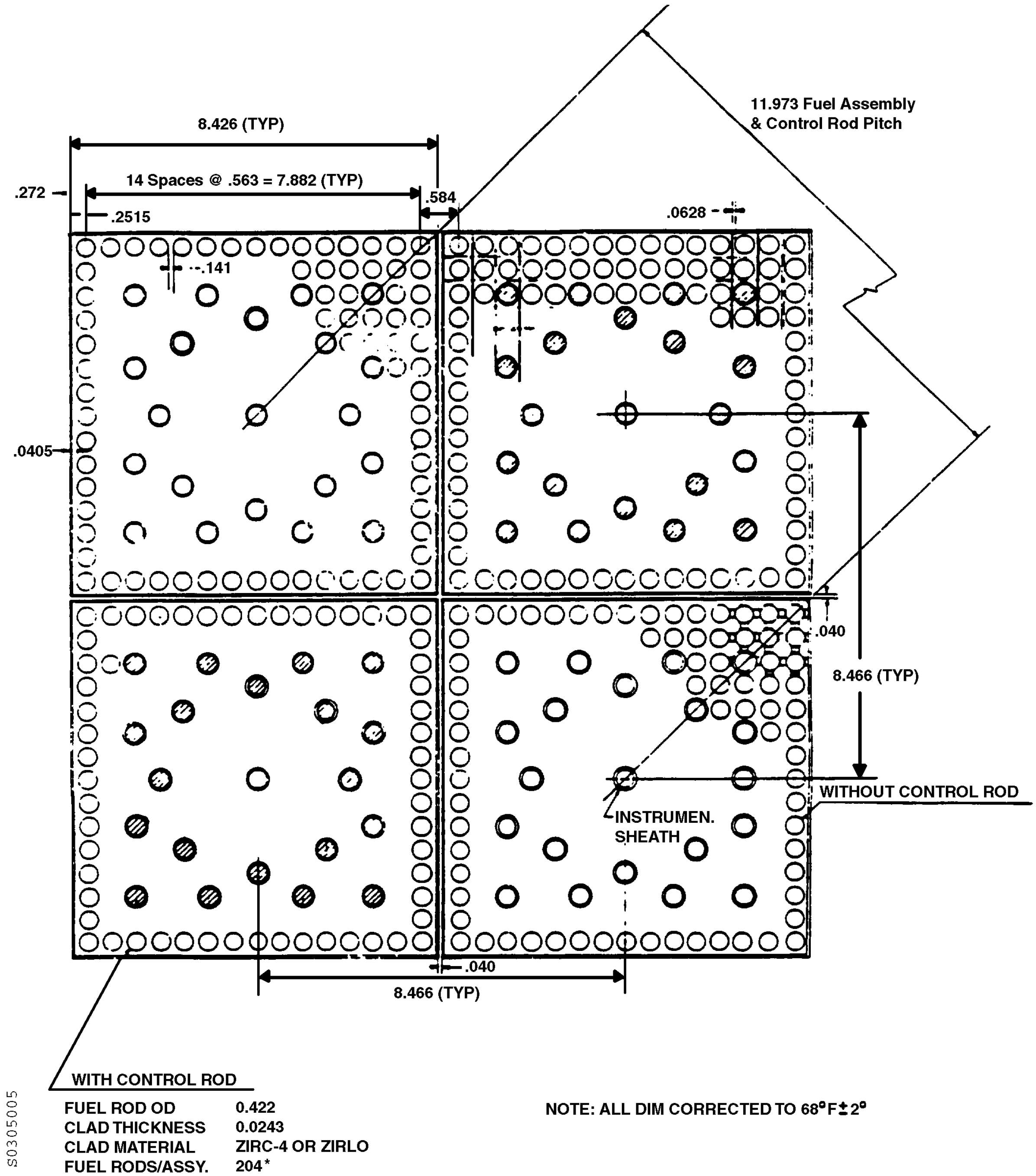


Figure 3.5-5
FUEL ASSEMBLY AND CONTROL ROD ASSEMBLY CROSS SECTION



FUEL ROD OD	0.422
CLAD THICKNESS	0.0243
CLAD MATERIAL	ZIRC-4 OR ZIRLO
FUEL RODS/ASSY.	204*

NOTE: ALL DIM CORRECTED TO 68°F±2°

* RECONSTITUTED FUEL ASSEMBLIES MAY HAVE LESS THAN 204 RODS.

Figure 3.5-6
LOWER CORE SUPPORT STRUCTURE

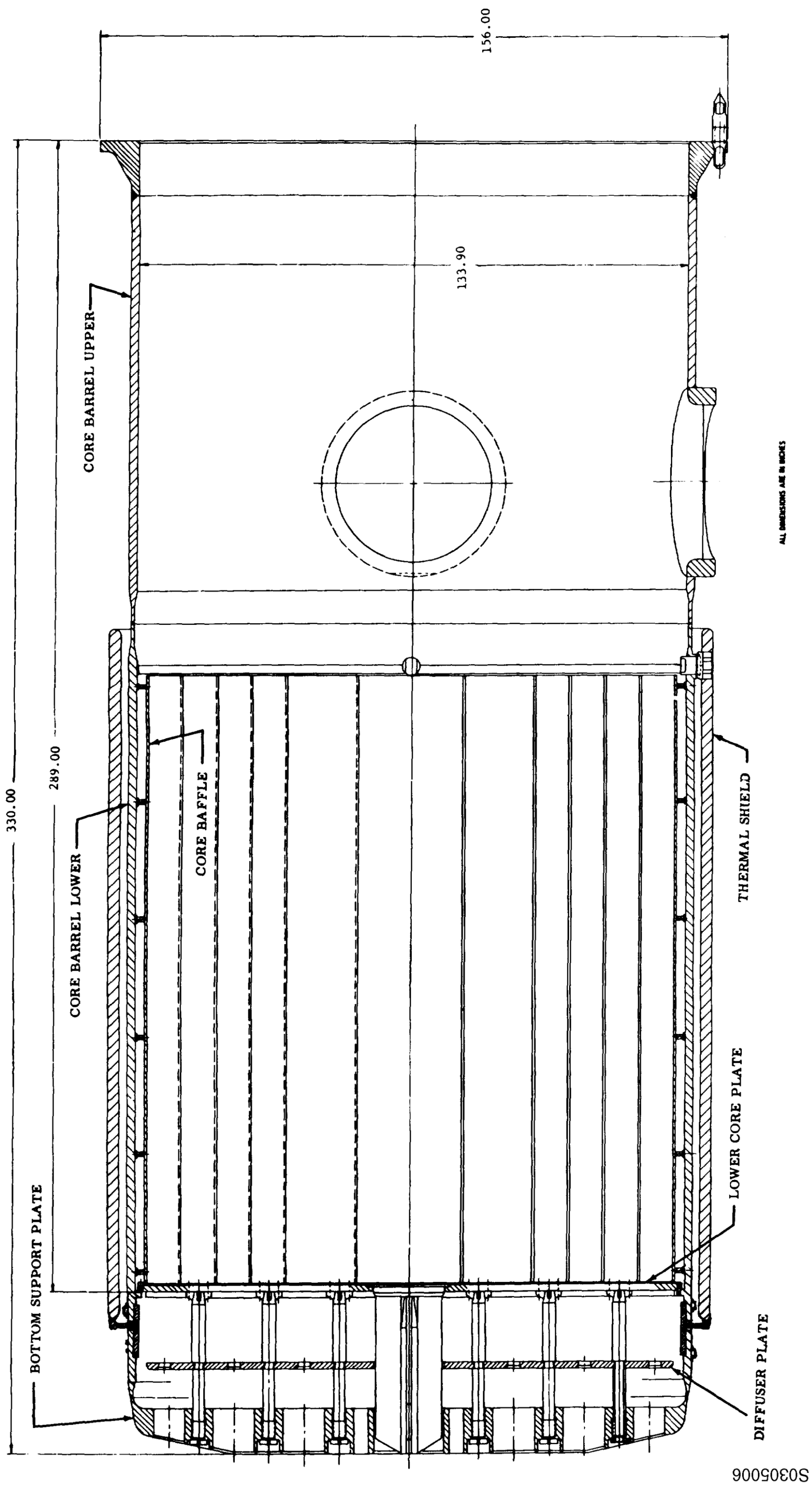


Figure 3.5-7
UPPER CORE SUPPORT ASSEMBLY

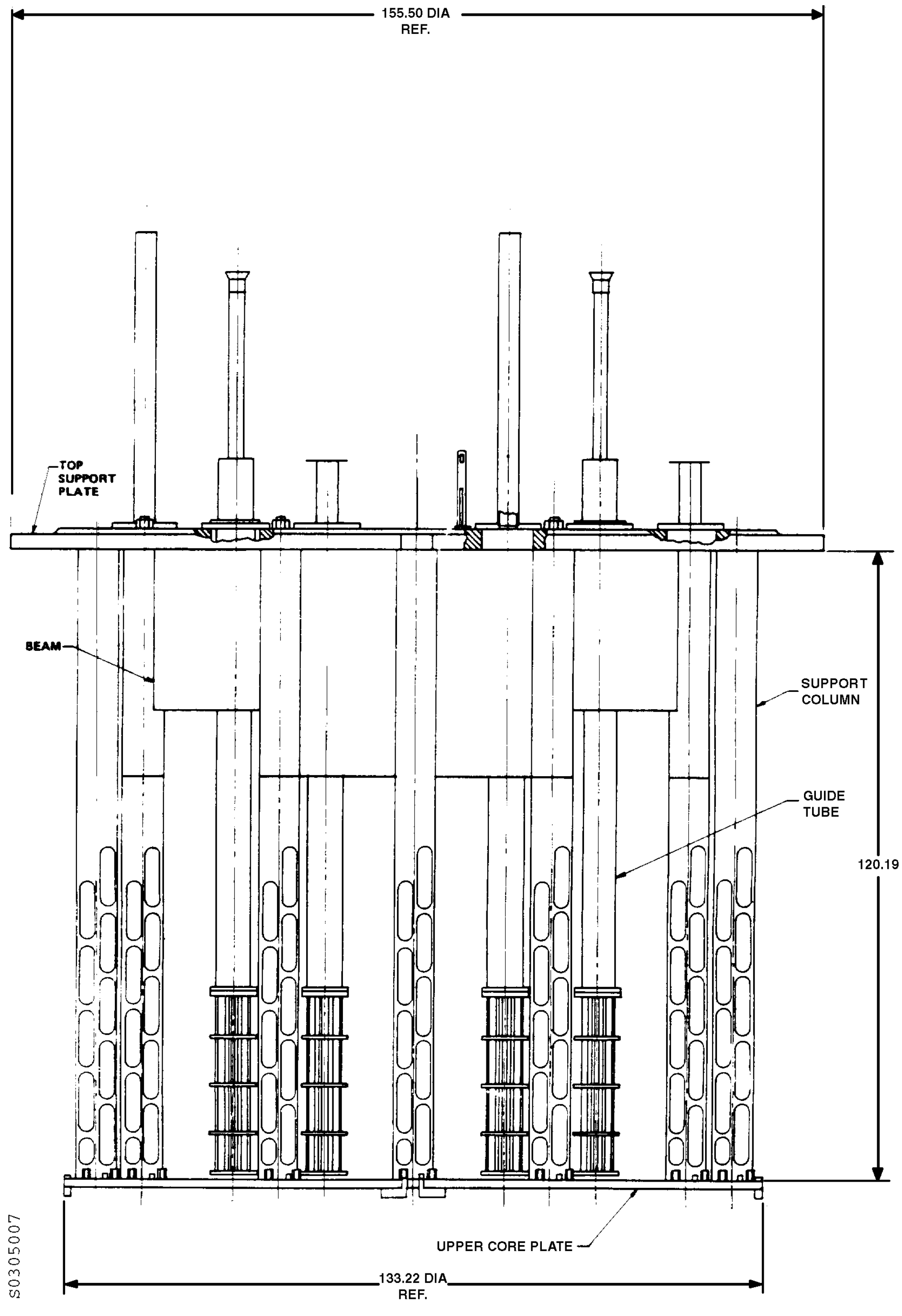


Figure 3.5-8
GUIDE TUBE ASSEMBLY

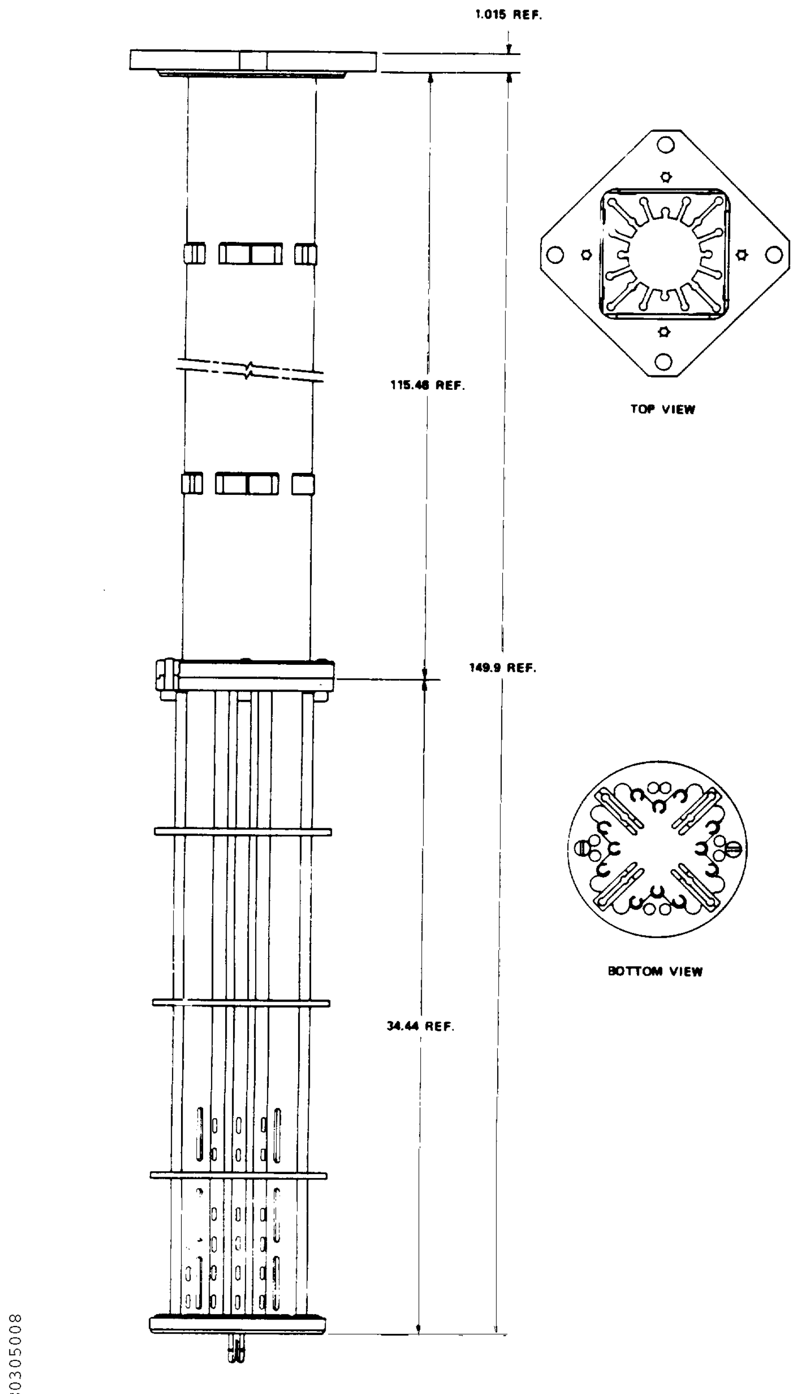
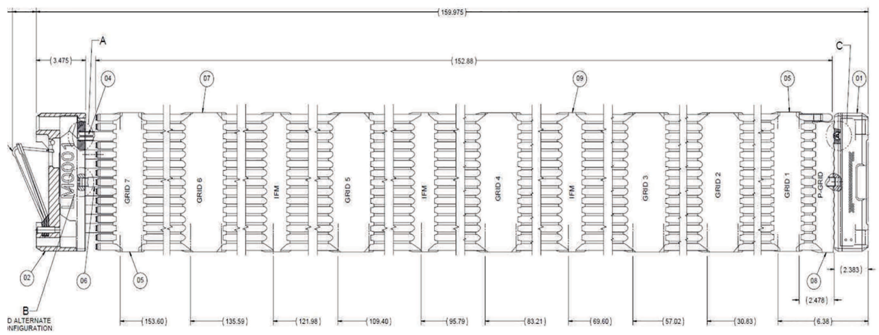
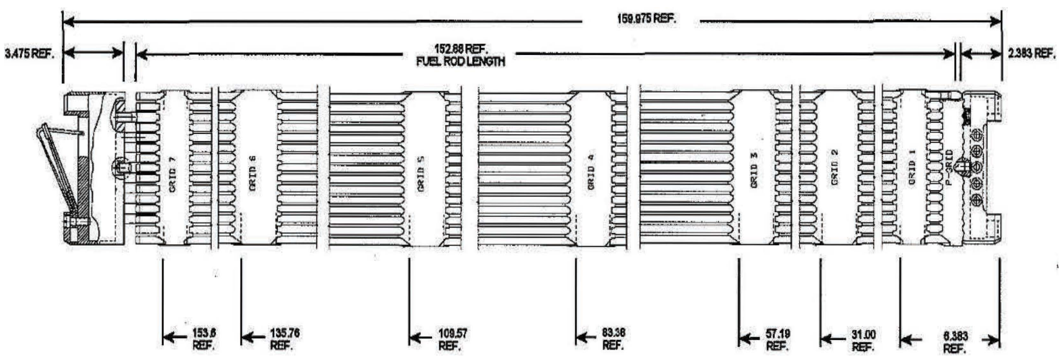


Figure 3.5-9
OUTLINE FOR TYPICAL 15 x 15 UPGRADE, SIF, AND
15 x 15 LOPAR FUEL ASSEMBLIES

15 x 15 Upgrade



15 x 15 SIF (OFA)



15 x 15 LOPAR

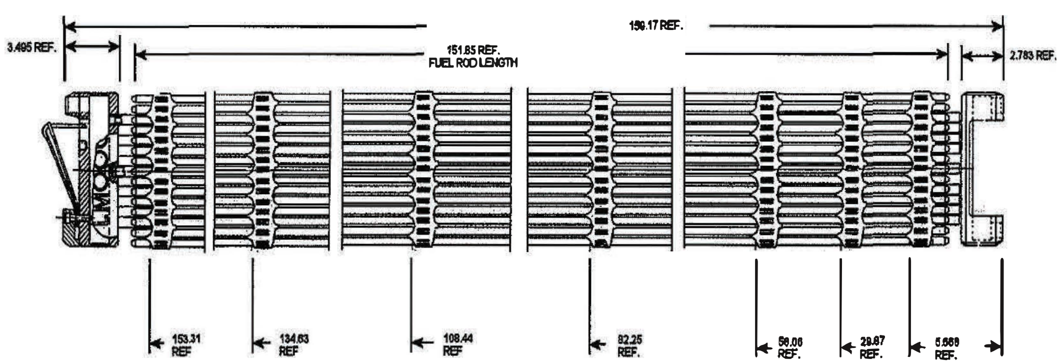
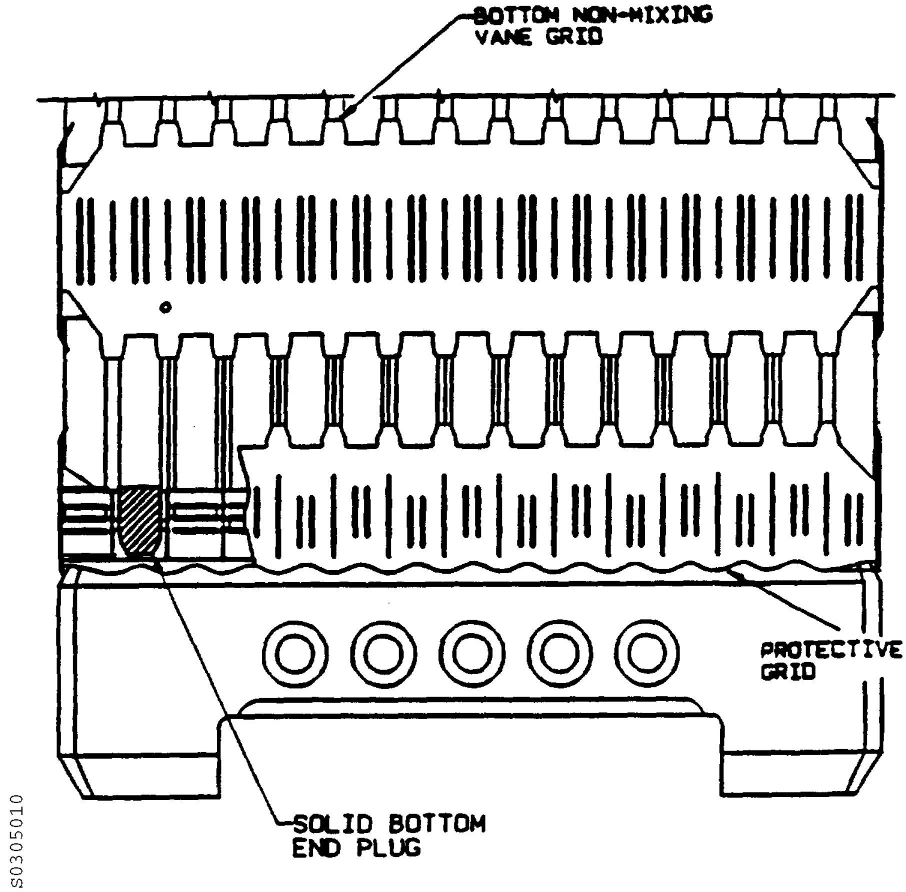


Figure 3.5-10
BOTTOM NOZZLE/PROTECTIVE GRID/FUEL ROD INTERFACE



Note: Starting with Batch 28, the flow communication holes shown on the bottom nozzle were removed with the introduction of the modified Debris Filter Bottom Nozzle. Batch 28 also introduced the Robust Protective Grid.

Note: Starting with Batch 33, the Advanced Debris Filter Bottom Nozzle was introduced which lowered the side skirts to help improve debris mitigation. Small flow holes were added to the new skirt to maintain flow to the baffle-former region while still reducing the overall lateral flow path available to debris.

Figure 3.5-11
REPRESENTATIVE GRID ASSEMBLY (INCONEL MIXING VANE GRID SHOWN)

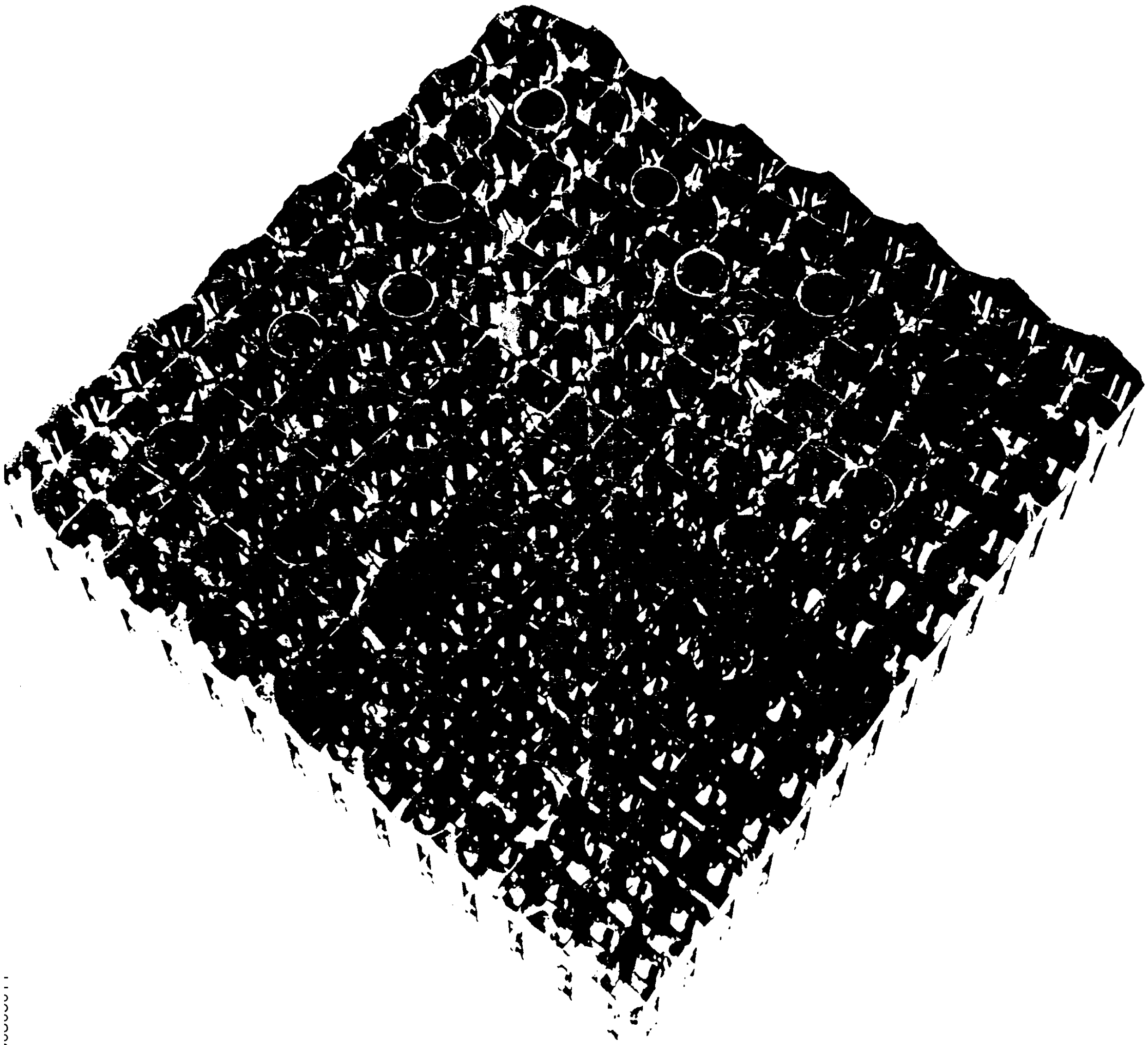


Figure 3.5-12
CONTROL ROD ASSEMBLY OUTLINE

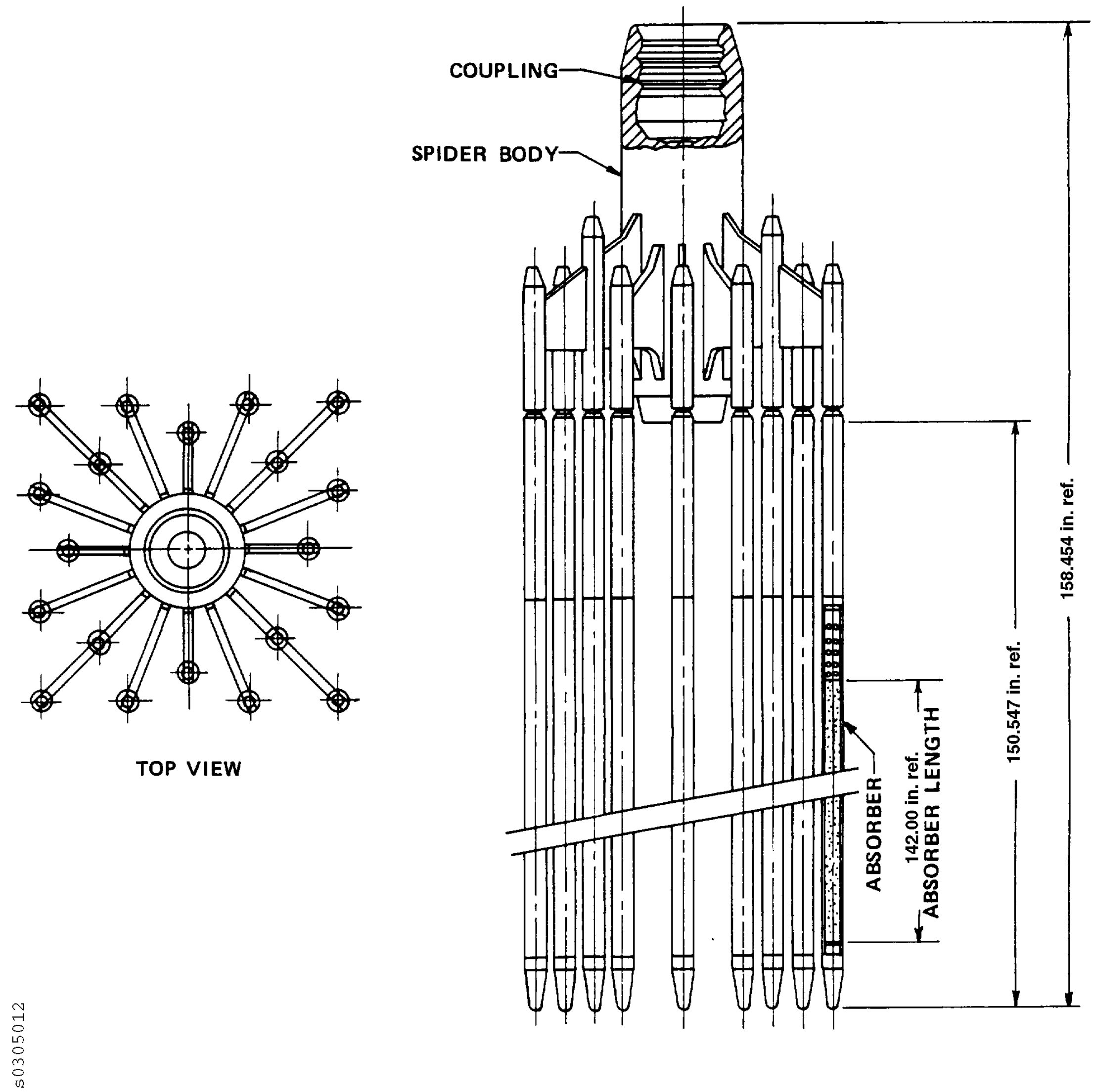


Figure 3.5-13
DETAIL OF BURNABLE POISON ROD

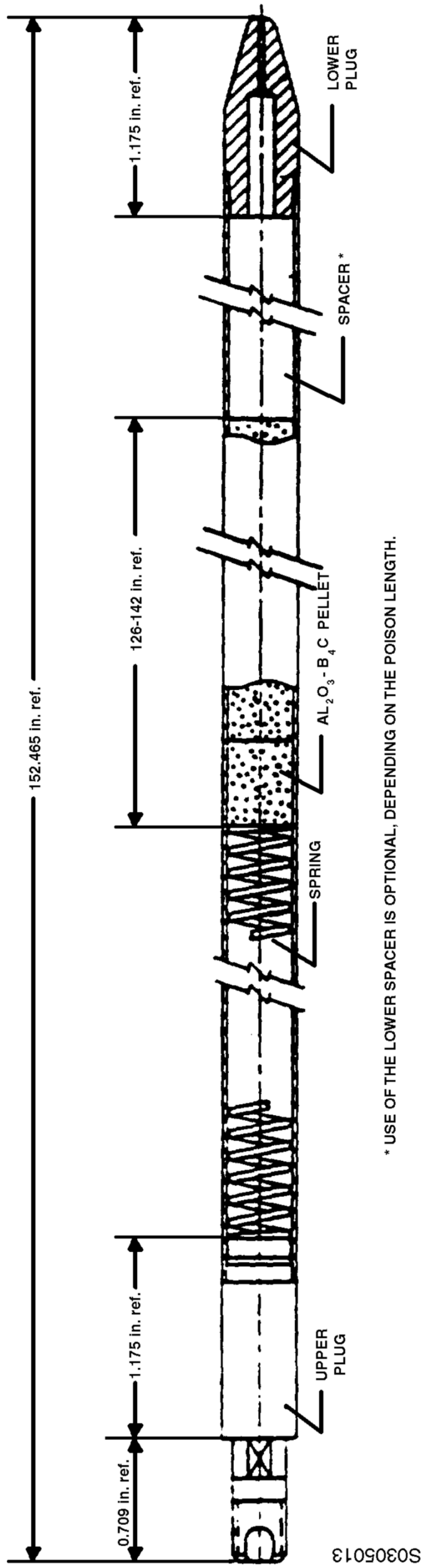


Figure 3.5-14
CONTROL ROD DRIVE MECHANISM ASSEMBLY

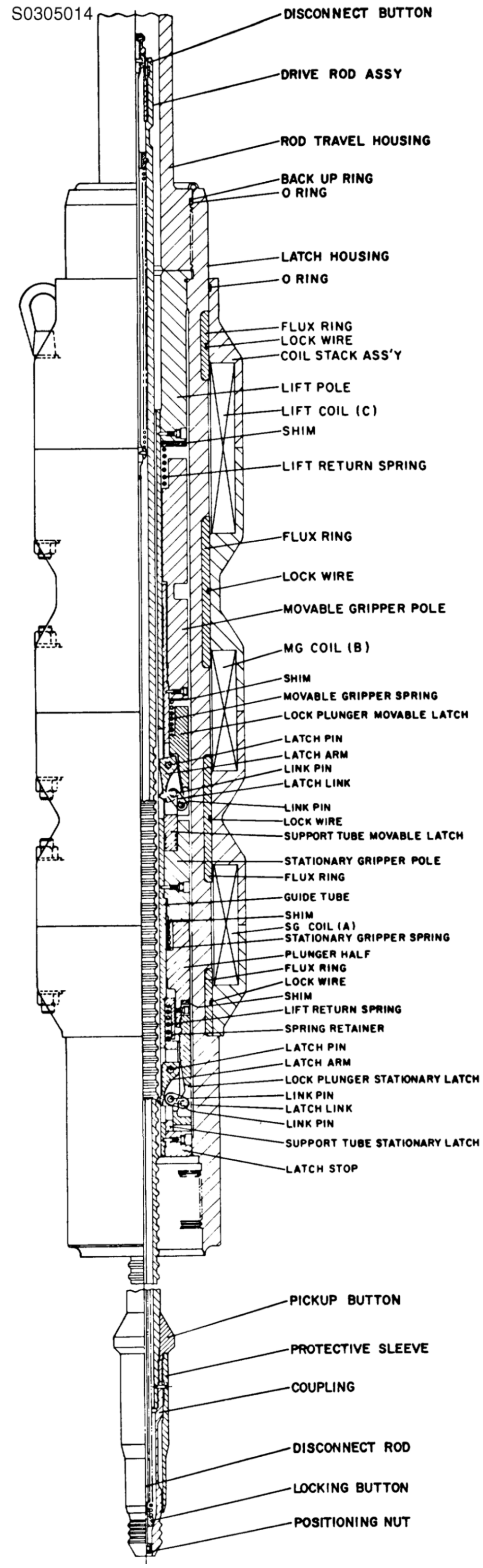
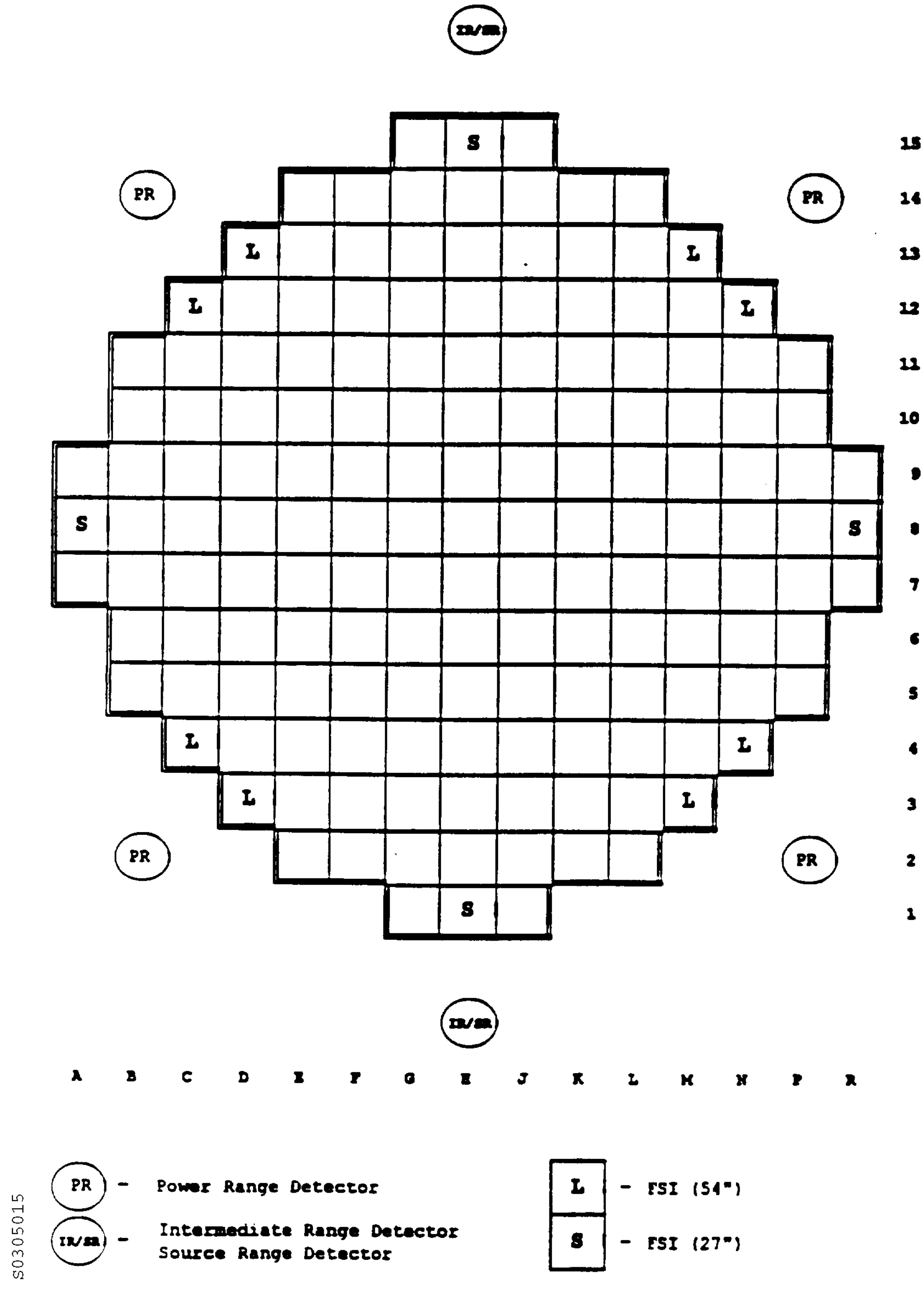


Figure 3.5-15
SURRY UNIT 1 FSI AND EXCORE DETECTOR LOCATIONS



Note that FSIs were removed after Cycle 20 of Unit 1.

Figure 3.5-16
SURRY UNIT 1 FLUX SUPPRESSION INSERT (FSI) ASSEMBLY

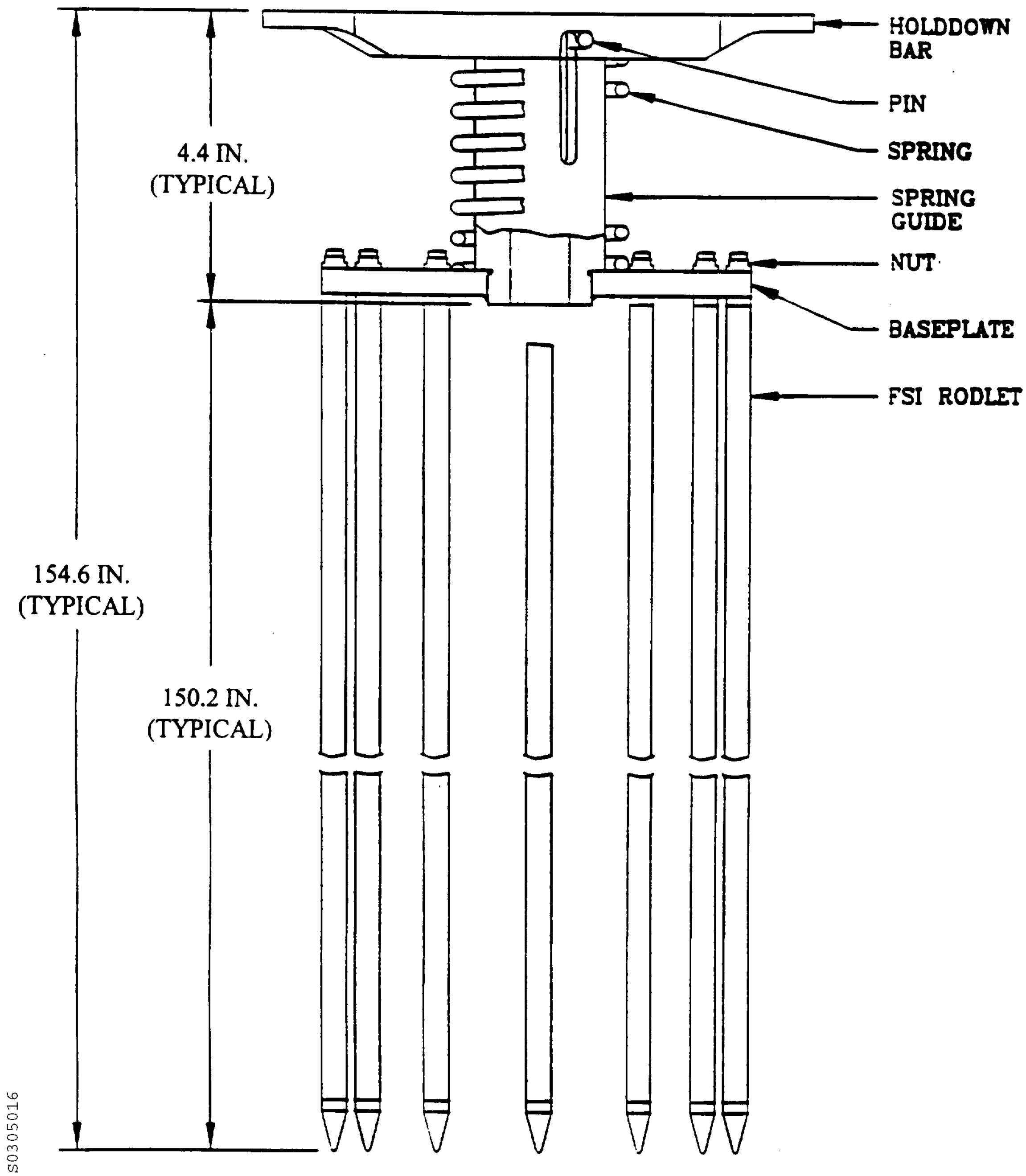
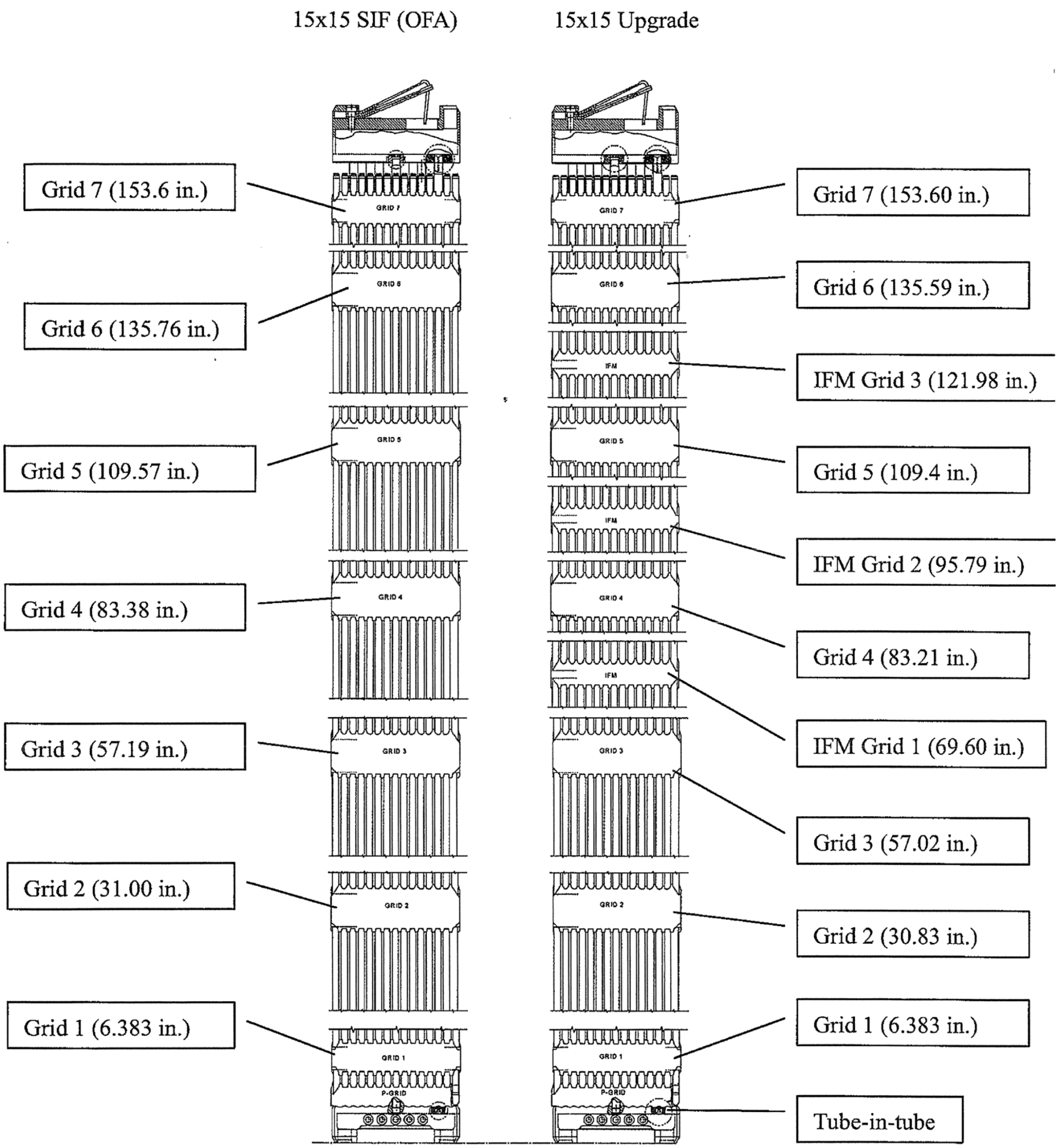


Figure 3.5-17
COMPARISON OF THE 15 X 15 SIF (OFA) AND 15 X 15 UPGRADE DESIGNS



(Dimensions referenced for each grid above reflect the height from the bottom of the fuel assembly to the top of the subject grid's inner strap. All dimensions are reference dimensions)

Intentionally Blank

3.6 TESTS AND INSPECTIONS

3.6.1 Physics Tests

3.6.1.1 Tests to Confirm Reactor Core Characteristics

A detailed series of start-up physics tests are performed each cycle from zero power up to and including 100% power. As part of these tests, a series of core power distribution measurements are made from at or below 50% power to 100% power by means of the core movable detector system. These measurements are analyzed and the results compared with the analytical predictions upon which safety analyses were based.

3.6.1.2 Tests Performed During Operation

To detect and eliminate possible errors in the calculations of the initial reactivity of the core and the reactivity depletion rate, the predicted relation between fuel burnup and the boron concentration necessary to maintain adequate control characteristics is normalized to accurately reflect actual core conditions. When full power is reached initially during each cycle, and with the control groups in the desired positions, the boron concentration is measured and the predicted curve is adjusted to this point. As power operation continues, the measured boron concentration is compared with the predicted concentration, and the slope of the curve relating burnup and reactivity is compared with that predicted. This normalization should be completed after about 10% of the cycle burnup has occurred. Thereafter, actual boron concentration can be compared with the predicted concentration, and the reactivity prediction of the core can be continuously evaluated.

Any reactivity anomaly greater than 1% would be unexpected, and its occurrence would be thoroughly investigated and evaluated.

3.6.2 Thermal/Hydraulic Tests and Inspections

General hydraulic tests on models have been used to confirm the design flow distributions and pressure drops (References 1 & 2). Fuel assemblies and control and drive mechanisms are also tested in this manner. Appropriate onsite measurements are made to confirm the design flow rates.

Vessel and internals inspections were reviewed prior to initial startup to confirm such thermal and hydraulic design values as bypass flow. A reactor coolant flow test, as noted in Table 13.3-1, was performed following fuel loading but before initial criticality to verify that proper coolant flow rates had been used in the core thermal and hydraulic analysis. Periodic testing is performed to verify the RCS flow rates used in design calculations are met.

3.6.3 Core Component Tests and Inspections

To ensure that all materials, components, and assemblies conformed to the design requirements, a release point program was established with the manufacturer. This program required surveillance of all raw materials, special processes (i.e., welding, heat treating, non-destructive testing, etc.), and those characteristics of parts that directly affected the assembly and alignment of the reactor internals. The surveillance was accomplished by the issuance of an Inspection Release by the quality control organization after conformance had been verified.

A resident quality control representative performed a surveillance/audit program at the manufacturer's facility, witnessed the required tests and inspections, and issued the inspection releases. An example would be the radiographic examination of the welds joining core barrel shell courses.

Components and materials supplied by Westinghouse to the assembly manufacturer were subjected to a similar program. Quality control engineers developed inspection plans for all raw materials, components, and assemblies. Each level of manufacturing was evaluated by a qualified inspection for conformance, e.g., witnessing the ultrasonic testing of core plate raw material. Upon completion of specified events, all documentation was audited prior to releasing the material or component for further manufacturing. All documentation and inspection releases are maintained in the quality control central records section. All materials are traceable to the mill heat number.

In conclusion, a set of "as built" dimensions were taken to verify conformance to the design requirements and ensure proper fitup between the reactor internals and the reactor pressure vessel.

3.6.3.1 **Fuel Product Assurance**

Fuel product assurance philosophy is generally based on the performance of inspections by the supplier to a 95% confidence that at least 95% of the product meets specification, unless otherwise noted. This confidence level is based on past experience gained during the manufacturing of over 10,000 metric tons of uranium cores. The following inspections are included:

1. Component parts - Parts received are generally inspected to a 95×95 confidence level. The characteristics inspected depend upon the component parts, and include dimensional and visual inspections, and check audits of test reports, material certifications, and non-destructive examinations such as X-ray and ultrasonic tests. Supplier material processes and component specifications specify in detail the inspections to be performed. All material used in the manufacture of the core is accepted and released by Quality Control.

2. Pellets - Inspection is performed to a 95×95 confidence level for the dimensional characteristics such as diameter, length, and squareness of ends. Additional visual inspections are performed for cracks, chips, and pores according to standards established at the beginning of production. These standards are based upon standards used in previous cores that have in turn served as standards for millions of pellets manufactured and used in operating cores. Density is determined in terms of weight per unit length. Chemical analyses are performed on each blend of pellets throughout pellet production. The hydrogen content of pellets loaded into fuel tubing is also tested and controlled.

Pellets that are coated with a boride material for use in integral fuel burnable absorber (IFBA) rods undergo additional inspections to determine the linear boron concentration on the pellet and the adherence of the coating.

3. Rod Inspection - Fuel rod inspection consists of the following non-destructive examination techniques and methods associated with the parameters or characteristics identified:

   a. *Leak testing* - Each rod is tested, using a calibrated mass spectrometer, with helium being the detectable gas.

   b. *Enclosure welds* - Rod welds are inspected by ultrasonic test or x-ray as an alternative method in accordance with a qualified technique and the applicable specification.

   c. *Dimensional* - All rods are dimensionally inspected prior to final release. The requirements include such items as camber and visual appearance. A sample of rods is evaluated for length.

   d. *Plenum dimensions* - All fuel rods are inspected by gamma scanning radiography or other approved methods to ensure proper plenum dimensions.

   e. *Pellet-to-pellet-gaps* - All fuel rods are inspected by gamma scanning or other approved methods to ensure that no significant gaps exist between pellets.

   f. *Gamma scanning* - Non-IFBA fuel rods are active gamma scanned to verify enrichment control prior to acceptance for assembly loading. IFBA fuel rods are passive gamma scanned to verify enrichment control and zone lengths prior to acceptance for assembly loading.

   Traceability of rods and associated rod components is maintained throughout manufacture and Quality Control release.

4. Final QC Release - The rods, upon final inspection, are released and available for fuel assembly loading.

5. Assembly - Inspection consists of 100% inspection for drawing and specification requirements.

6. Other inspections - The following inspections are performed as part of the routine inspection operation:

   a. Measurements, other than those specified above, that are critical to thermal/hydraulic analyses are obtained to enable evaluation of manufacturing variations to a 99.5% confidence level.

   b. Tool and gauge inspection and control is performed, including standardization to primary and secondary working standards. Tool inspection is performed at prescribed intervals on all serialized tools. Complete records are kept of the calibration and condition of tools.

c. Check audit inspection of all inspection activities and records to ensure that prescribed methods are followed and that all records are correct and properly maintained.

d. Surveillance of outside contractors, including approval of standards and methods, is performed where necessary.

To prevent the possibility of mixing enrichments during fuel manufacture and assembly, meticulous process control is exercised.

The UF_6 gas is normally received from the enrichment plant in sealed containers, the contents of which are fully identified.

Upon receipt by the supplier, an additional identification tag completely describing the contents is affixed to the containers before transfer to UF_6 storage.

The UF_6 is converted to UO_2. After conversion the UO_2 is normally milled and then blended. The blended powder is inspected by Quality Control and released for pelleting based on a chemical analysis.

Pellet production lines are physically separated from each other, and pellets of only a single enrichment and design are produced in a given production line or a segregated part of the line.

Finished pellets are placed on trays which are identified as to enrichment and transferred to closed storage carts.

If the storage carts are moved out of the established control area, the carts are locked and sealed to prevent mixing of pellets of different designs and enrichments. Unused powder and substandard pellets are returned to storage.

Loading of the pellets into the cladding is again accomplished in separated production lines, and again only one design and enrichment at a time is loaded on a line.

A bar code that provides traceability information is laser etched on each fuel tube. The bar code provides a reference of the fuel pellets contained in the fuel rods. Other approved methods of identification may be used.

At the time of installation into an assembly, an inspector verifies that all fuel rods in an assembly have the same contract identification, and that the top nozzle to be used on the assembly carries the correct identification information. The top nozzle identification is then used by manufacturing and station fuel handling personnel to maintain fuel assembly traceability. All fabrication plant personnel handling fuel materials should have thorough medical examinations and should be checked for color blindness.

3.6.3.2 **Control Rod, Burnable Poison Rod and Source Rod Tests and Inspections**

All clad/end plug and/or seal welds in control rods, burnable poison rods, flux suppression insert rods, and source rods are checked for integrity by visual inspection; ultrasonic test or, alternatively, may also be inspected by x-ray; and helium leakage in accordance with qualified techniques and supplier specifications. Beginning with Cycle 20 at both units, the feed burnable poison rods are fabricated with a new end plug welding process, and the vendor no longer performs ultrasonic testing or x-ray on these components.

3.6 REFERENCES

1. G. Hetsroni, *Hydraulic Tests of the San Onofre Reactor Model*, WCAP-3269-8, 1964.
2. G. Hetsroni, *Studies of the Connecticut-Yankee Hydraulic Model*, WCAP-2761, 1965.
3. Westinghouse Product Specification NFP 31038, Revision 28, *Fuel Rod Assemblies*.
4. Westinghouse Product Specification NFP 31032, Revision 20, *Uranium Oxide Powder*.
5. Westinghouse Product Specification NFP 31029, Revision 41, *Uranium Dioxide Pellets*.
6. Westinghouse Process Specification NPS 80030 UM, Revision 22, *Manufacturing Uranium Oxide Powder*.
7. Westinghouse Process Specification NPS 80030 XL, Revision 42, *Manufacturing of Uranium Dioxide Pellets*.

Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 4

Intentionally Blank

Chapter 4: Reactor Coolant System
Table of Contents

Chapter 4: Reactor Coolant System
Table of Contents (continued)

Chapter 4: Reactor Coolant System
Table of Contents (continued)

Chapter 4: Reactor Coolant System

List of Tables

Chapter 4: Reactor Coolant System

List of Figures

Intentionally Blank

CHAPTER 4 REACTOR COOLANT SYSTEM

4.1 DESIGN BASES

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

4.1.1 Performance Objectives

The reactor coolant system transfers the heat produced by the nuclear reaction in the core to the steam generators, where steam is generated to drive the turbine generator. Borated demineralized light water is circulated at the flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance presented in Section 3.4. The water also acts as a neutron moderator, a reflector, and a solvent for the neutron absorber.

The reactor coolant system provides a boundary for containing the primary coolant under operating temperature and pressure conditions. It serves to confine radioactive material and limits its uncontrolled release to the secondary system and to the other parts of the unit. During transient operation, the system heat capacity attenuates thermal transients generated by the core or extracted by the steam generators. The reactor coolant system accommodates coolant volume changes within the protection system criteria both during normal operation and during anticipated transient conditions.

The thermal-hydraulic effects resulting from loss of power to the reactor coolant pumps are reduced to acceptable levels by appropriate selection of the inertia of the reactor coolant pumps so that core damage does not result. The layout of the system ensures natural circulation capability following a loss-of-flow incident to permit cooldown without overheating the core.

A portion of the reactor coolant system piping is used by the safety injection system to deliver cooling water to the core for emergency core cooling during a loss-of-coolant accident (LOCA).

4.1.2 Design Criteria

4.1.2.1 Quality Standards

Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice (Section 4.1.6). Details of the quality assurance test procedures and inspection acceptance levels are given in Sections 4.3.1 and 4.4. Particular emphasis is placed on the quality assurance of the reactor vessel

4.1.2.2 **Performance Standards**

All piping, components, and supporting structures are designated and designed as Seismic Class I components, and are designed to withstand the jet thrust forces of a pipe rupture[1]. Details are given in Section 4.1.3.

4.1.2.3 **Records Requirements**

Records of the design, fabrication, quality control, and construction of the major reactor coolant system components and the related engineered safety features components are maintained by or are available to Vepco throughout the station life.

4.1.2.4 **Missile Protection**

The dynamic effects of a pipe rupture accident[1] and other postulated accidents have been evaluated in the detailed layout and design of the high-pressure equipment and missile barriers. The design ensures the missile protection necessary to maintain functional capability.

4.1.2.5 **Reactor Coolant Pressure Boundary**

The reactor coolant system, with its control and protective provisions, accommodates the pressures and temperatures attained under all expected modes of station operation or anticipated system interactions, and maintains the stresses within applicable code stress limits (Section 4.3.1).

4.1.2.6 **Monitoring Reactor Coolant Leakage**

Positive indications in the control room of leakage of coolant from the reactor coolant system to the containment are provided by equipment that permits continuous monitoring of the containment internal pressure, temperature, and gaseous and particulate activity; of containment sump water level; of makeup water to the primary system; and of the temperature of water leaking from the reactor vessel through its head flange. This equipment provides information that is indicative of a basic level of leakage from primary systems and components. Any increase observed may be indicative of an increase in the leakage rate from the reactor coolant system. The equipment provided is capable of monitoring such a change. Refer to Section 4.2.7.

4.1.2.7 **Reactor Coolant Pressure Boundary Capability**

The reactor coolant pressure boundary is capable of accommodating, without rupture, the loads resulting from a sudden reactivity insertion such as results from rod ejection. Details of this analysis are provided in Section 14.3.3.

The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod assemblies are used to control load variations only, and core depletion is followed with boron dilution, only the control rod assemblies in the controlling groups are

1. As discussed in Section 4.1.3 and Section 15.6.2, it is no longer necessary to consider the dynamic effects of postulated rupture of the primary reactor coolant loop piping. However, other pipe ruptures as discussed in Section 15.6.2 must still be considered.

inserted in the core at power, and at full power these rods are only partially inserted. A rod insertion limit monitor is provided as an administrative aid to the operator to ensure that this condition is met.

The reactor design is such that the maximum fuel temperature for the highest-worth ejected rod is below the threshold for resultant damage to the primary system pressure boundary.

The failure of a rod mechanism housing, causing a control rod assembly to be rapidly ejected from the core, is evaluated as a theoretical but not credible accident. While limited fuel damage could result from this hypothetical event, the fission products would be confined to the reactor coolant system and the reactor containment. The environmental consequences of rod ejection would be less severe than from the hypothetical LOCA, for which public health and safety is shown to be adequately protected.

4.1.2.8 **Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention**

The probability of a rapid propagation type failure is remote. The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of this type of failure.

In the core region of the reactor vessel it is expected that the notch toughness of the material will change as a result of fast neutron exposure. This change is evidenced as a shift in the reference temperature for the nil ductility transition (RT_{NDT}) which is factored into the operating procedures. The RT_{NDT} shift of the vessel material and welds, due to radiation effects, is monitored by an integrated surveillance program that conforms with the requirements of 10 CFR 50, Appendix H and ASTM E 185, and is described in Section 4.1.7.

All pressure-containing components of the reactor coolant system are designed, fabricated, inspected, and tested in conformance with the applicable codes. Further details are given in Section 4.1.6.

The reactor vessel closure heads were replaced with closure heads with impact properties that exceed the original head requirements. The low alloy steels of the replacement closure head flanges have an RTNDT of -67°F for Unit 1 and -60°F for Unit 2. 10 CFR 50 Appendix G requires the minimum temperature for the pressure-temperature limit curves be greater than or equal to the RTNDT of the limiting flange-region material. These replacement closure head flange RTNDT values are less limiting than that assumed in the development of the Technical Specification pressure/temperature limit curves. Therefore, the Technical Specification pressure/temperature limit curves will not change.

4.1.2.9 **Reactor Coolant Pressure Boundary Surveillance**

The design of the reactor vessel and its arrangement in the system provides the capability for accessibility during service life to all the internal surfaces of the vessel and to certain external zones of the vessel, including the nozzle to reactor coolant piping welds and the top and bottom heads. The reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete.

4.1.3 Design Characteristics

4.1.3.1 Design Pressure

The reactor coolant system design and operating pressure, the safety, power relief, and pressurizer spray valve design setpoints, and the protection system pressure setpoints are listed in Table 4.1-1. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics. The design pressures and data for the respective system components are listed in Tables 4.1-2 through 4.1-7.

4.1.3.2 Design Temperature

The design temperature for each component is selected to be above the maximum coolant temperature in that component under all normal and anticipated transient load conditions. The design and operating temperatures of the respective system components are listed in Tables 4.1-2 through 4.1-7.

4.1.3.3 Seismic Loads

The seismic loading conditions are established by the operating-basis earthquake (OBE) and design-basis earthquake (DBE). The ground acceleration values and the basis for their selection are presented in Section 2.5. The seismic analysis of the reactor coolant system is described in more detail in Appendix 15A.

For the OBE loading condition, the nuclear steam supply system is capable of continued safe operation. Therefore, for this loading condition, critical structures and equipment are required to operate within allowable code stress limits. The seismic design for the design-basis earthquake provides a margin that ensures the capability to shutdown and maintain the nuclear facility in a safe condition. In this case, it is only necessary to ensure that the reactor coolant system components are able to perform their safety function. This has come to be referred to as the “no-loss-of-function” criterion and the loading condition as the “no-loss-of-function earthquake” loading condition.

The criteria adopted for allowable stresses and stress intensities in vessels and piping subjected to normal loads plus seismic loads are defined in Section 15A.

To further ensure against accident aggravation, the reactor coolant system has been checked for the combination of stresses associated with the design-basis earthquake and the most severe pipe rupture loadings on the reactor coolant system.[1] These stress loadings are designed to be below the limits assumed to cause rupture, as illustrated in Section 15A.

For the combination of normal and operating-basis earthquake loadings, the stresses in the support structures are designed to be within the limits of the applicable codes as discussed in Section 15A.

For the combination of normal and operating-basis earthquake loadings, and for the combination of these loads plus the most severe on the primary reactor coolant system due to postulated pipe rupture loadings[1], the stresses in the support structures are limited to values that ensure structural integrity and maintain the component stresses within the limit previously established.

4.1.4 Cyclic Loads

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to reactor coolant system temperature and pressure changes. These cyclic loads are introduced by normal power changes and reactor trip, start-up, and shutdown operations. The number of thermal and loading cycles used for design purposes are given in Table 4.1-8. Heatup and cooldown rates are limited as indicated in Section 4.2.6.

The number of cycles for unit heatup and cooldown at 100°F/hr was selected as a conservative estimate based on an evaluation of the expected requirements. The resulting number, which averages five heatup and cooldown cycles per year and was based on the original license period of 40 years, could be increased significantly; however, it is intended to represent a conservative realistic number rather than the maximum allowed by the design. This estimate has been retained for the 80-year renewed operating license period.

Although loss-of-flow and loss-of-load transients are not included in the tabulation, since the tabulation is intended to represent only normal design transients, the effects of these transients have been analytically evaluated and are included in the fatigue analysis for primary system components.

The reactor coolant system and its components are designed to accommodate 10% of full-power step changes in station load and 5% of full-power-per-minute ramp changes over the range from 15% full power up to and including, but not exceeding, 100% of full power without reactor trip. Automatic rod withdrawal is disabled. The station loading from 15% to 100% is accomplished by manual control rod withdrawal. Operator action will be needed to restore the station parameters to the reference values on design basis load increase transients. The reactor coolant system accepts a complete loss of load from full power with reactor trip. In addition, the steam dump system makes it possible to accept a 50% load rejection from full power without reactor trip.

1. As discussed in Section 15.6.2, it is no longer necessary to consider the dynamic effects of postulated rupture of the primary reactor coolant loop piping. However, other pipe ruptures as discussed in Section 15.6.2 must still be considered.

4.1.5 Service Life

The service life of reactor coolant system pressure components depends upon the material irradiation, unit operational thermal cycles, quality manufacturing standards, environmental protection, and adherence to established operating procedures.

The reactor vessel is the only component of the reactor coolant system that is exposed to a significant level of neutron irradiation. It is therefore the only component that is subject to any appreciable material irradiation effects. These effects are discussed in Section 4.1.7.

Reactor vessel design is based on the transition temperature method of evaluating the possibility of brittle fracture of the vessel material as a result of operations. The service life of the reactor coolant system components, as required by the ASME Code, Section III, for Class “A” vessels, is established for the 80-year design life. These operating conditions include the cyclic application of pressure loadings and thermal transients listed in Table 4.1-8.

4.1.6 Codes And Classifications

All pressure-containing components of the reactor coolant system are designed, fabricated, inspected, and tested in conformance with the applicable codes listed in Table 4.1-9.

The reactor coolant system is classified as Class I for seismic design. The load combinations for Class I design are described in Chapter 15.

The Westinghouse Equipment Specification for the reactor vessel contains many requirements that are supplemental to those specified in ASME Code, Section III. These requirements include the following:

1. Design
   a. Design pressures and temperatures have been selected to be above pressures and temperatures that would be expected to occur under all normal and transient conditions.
   b. A complete fatigue analysis was performed on the entire vessel.
2. Inspection and Quality Assurance
   a. In addition to the normal straight-beam ultrasonic examination required by the ASME Code, all pressure boundary plate material was examined by the angle-beam ultrasonic method.
   b. All weld deposit overlay cladding used for the vessel corrosion resistant lining was 100% ultrasonically inspected to verify that the cladding is bonded to the base metal.
   c. After the vessel hydrostatic test, all vessel and head internal surfaces were liquid penetrant inspected, and all external surfaces were magnetic particle inspected.

d. Prior to placing the vessel in service, an ultrasonic examination of pressure boundary welds was performed in accordance with the ASME Code for inservice inspection of nuclear reactor coolant systems.

e. In addition to the ASME Code-required third-party inspector, Westinghouse provided full-time quality assurance coverage in the Babcock & Wilcox Co. shop, and also in the Rotterdam Dockyard (RDM) shop during the fabrication of the Surry vessels.

f. In addition to the quality assurance coverage provided by Westinghouse, Vepco and the architect-engineer, Stone & Webster, performed regular quality assurance audits of reactor vessel fabrication as performed by RDM.

Unit 1 Reactor Vessel Closure Head was replaced with a closure head fabricated and manufactured in accordance with the French Construction Code (R-CCM) 1993 Edition with 1st Addenda June 1994, 2nd Addenda June 1995, 3rd Addenda June 1996 and Modification Sheets FM 797, 798, 801, 802, 803, 804, 805, 806, and 807. The sizing calculations and the stress and fatigue analysis were performed to ASME B&PV Code, Section III, 1995 Edition 1996 Addenda. The Design Report (Reference 14) certified that the closure head meets the design requirements and stress limits for the ASME B&PV Code, Section III, 1995 Edition addenda through 1996, except as noted below.

Exception: The CRDM Adapter Tube Assembly includes a friction weld at the bimetallic joint between the housing flange and the tube. The use of friction welds in the fabrication of vessels and piping is not in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code. Consideration of this weld as a Category B full penetration weld in the stress analysis is justified in the Report of Reconciliation (Reference 15) for the Surry Unit 1 replacement reactor vessel closure head.

The Unit 2 reactor vessel closure head was replaced with a closure head fabricated and manufactured by Mitsubishi Heavy Industries (MHI). The replacement reactor vessel closure head was designed and fabricated in accordance with ASME B&PV Code, Section III, 1995 Edition with 1996 Addenda. The stress and fatigue analyses were performed to ASME B&PV Code, Section III, 1995 Edition with 1996 Addenda. The Mitsubishi Heavy Industries Design Specification, Reference 16, for the Unit 2 reactor vessel head contains many requirements that are supplemental to those specified in ASME Code, Section III. These requirements include the following:

1. Design

   a. Design pressures and temperatures have been selected to be above the pressures and temperatures that would be expected to occur under all normal and transient conditions.

   b. A complete fatigue analysis was performed on the entire head.

2. Inspection and Quality Assurance

a. All weld deposit overlay cladding used for head corrosion resistant lining was 100% ultrasonically inspected to verify that the cladding is bonded to base metal.

b. The final non-destructive examination of the pressure boundary materials was conducted in the following:

(1) Low alloy materials were magnetic particle examined after final machining of the reactor vessel head.

(2) Surfaces that are clad were magnetic particle examined prior to cladding.

(3) Surfaces were magnetic particle examined after removal of temporary attachments.

4.1.7 Irradiation Surveillance Program

4.1.7.1 General Description

In the surveillance program (References 4 & 5) the evaluation of the radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens, and post-irradiation testing of Charpy V-notch and tensile specimens. Wedge opening loading (WOL) fracture mechanics test specimens are also irradiated for potential supplemental testing. This program is directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach, and is in accordance with ASTM-E-185, *Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors*. Low melting point alloys are included as thermal control specimens. They provide indication if the area of surveillance has exceeded a given temperature.

The reactor vessel surveillance program uses eight specimen capsules, more than the minimum number recommended by ASTM-E-185. The capsules are located about 3 inches from the vessel wall, directly opposite the center portion of the core. Elevation and plan views showing the location and dimensional spacing of the capsules with relation to the core, thermal shield, and vessel and weld seams are shown in Figures 4.1-1 and 4.1-2, respectively. The capsules can be removed or relocated when the vessel head and upper internals are removed. The capsules contain specimens of some of the materials found in the Surry reactor vessel. These specimens include material from the shell plates located in the core region of the reactor and associated weld metal and heat-affected-zone metal. (As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01% will be made for surveillance material base metals and as deposited weld metal.) In addition, 8 Charpy specimens in each of the surveillance capsules are made from fully documented specimens of SA533 Grade B correlation monitor material obtained through Subcommittee II of ASTM Committee E10, Radioisotopes and Radiation Effects. The eight Unit 1 capsules contain approximately 32 tensile specimens, 240 Charpy V-notch specimens (which include weld metal and heat-affected-zone material), and 40 WOL specimens. The eight Unit 2 capsules contain a total of 32 tensile specimens, 352 Charpy V-notch specimens (which include weld metal and heat-affected-zone material), and 32 WOL specimens.

The dosimeters permit evaluation of the flux seen by the specimens and vessel wall. In addition, thermal monitors made of low-melting alloys are included to monitor temperature of the specimens. The specimens are enclosed in a tight-fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. Vessel material sufficient for additional capsules is kept in storage should the need arise for additional replacement test capsules in the program.

The anticipated degree to which the specimens will perturb the fast neutron flux and energy distribution will be considered in the evaluation of the surveillance specimen data. Verification and possible readjustment of the calculated wall exposure will be made by use of data on all capsules withdrawn.

Specimen data for Unit 1 capsules are given in Table 4.1-10. Specimen data for Unit 2 capsules are given in Table 4.1-11. The schedule for removal and reinsertion of capsules is shown on Table 4.1-12 (Unit 1) and Table 4.1-13 (Unit 2). Irradiated surveillance capsules which do not require testing to satisfy ASTM E-185 are designated as standby capsules. There currently is no detailed regulatory guidance regarding the treatment of standby capsules that are removed but not tested. To address this concern, all surveillance capsules placed in storage will be maintained for possible future insertion. If one or more capsules will not be maintained in such a way as to permit future insertion, then the NRC staff will be notified of this change.

Irradiation of the specimens is higher than the irradiation of the adjacent vessel wall because they are closer to the core than the vessel itself. Since these specimens experience higher irradiation and are actual samples from the materials used in the vessel, the RT_{NDT} measurements are representative of the vessel at a later time in life. Data from fracture toughness samples (WOL) are expected to provide additional information for use in determining allowable stresses for irradiated material, if required.

The reactor vessel surveillance capsule holders are located at 15, 25, 35, and 45 degrees relative to the core symmetry, as shown in Figure 4.1-2.

The unirradiated reference temperature for the nil ductility transition (RT_{NDT}) for a material may be determined either by large specimen drop weight tests or by Charpy V-notch impact tests. The unirradiated RT_{NDT} is the higher of (a) the nil ductility transition temperature as determined by drop weight test, or (b) the temperature at which Charpy test specimens oriented normal to the major working direction exhibit at least 50 ft-lb of absorbed energy and 35 mils of lateral expansion, minus 60°F. RT_{NDT} values for irradiated materials are calculated in the manner prescribed by Regulatory Guide 1.99, Revision 2, *Radiation Embrittlement of Reactor Vessel Materials* using data from the rector vessel material surveillance program.

Tables 4.1-14 and 4.1-15 provide the unirradiated RTNDT values as determined by NB-2331 of Section III of the ASME B&PV Code or one of the 3 alternative methods for determining the RTNDT described below.

- Topical Report BAW-2308
- Branch Technical Position (BTP) 5-3, Revision 2
- EPRI Report BWRVIP-173-A, Appendix B, Alternative Approach 2 (GE Method)

Framatome ANP Topical Report BAW-2308, Revision 1-A (Reference 17) provides an alternate method for determining the adjusted RT_{NDT} (reference nil-ductility temperature) of the Linde 80 weld materials present in the beltline region of the reactor pressure vessels at Surry Power Stations Unit 1 and 2. Topical Report BAW-2308, Revision 1-A, also provides revised initial (unirradiated) RT_{NDT} values and initial (unirradiated) uncertainty terms for the Linde 80 weld materials present in the reactor pressure vessels of Surry Units 1 and 2. Topical Report BAW-2308, Revision 1-A was approved by the NRC in August 2005.

The alternative initial reference temperature values provided in Topical Report BAW-2308, Revision 1-A are obtained by using the B&W Owners Group Master Curve reference temperature database and ASME Code Case N-629. As described in Topical Report BAW-2308, Revision 1-A, previous initial RT_{NDT} values for Linde 80 class of weld materials were determined by the 50 ft-lb Charpy impact energy according to NB-2331 of Section III of the ASME B&PV Code, which gave overly conservative initial RT_{NDT} values.

The Master Curve methodology permits establishment of a reference temperature, T_0, using direct fracture toughness testing of compact tension (CT) specimens ranging in size from 0.5-inch thickness CTs (0.5T-CTs) to 2.0T-CTs, and precracked Charpy-sized bend specimens, based on ASTM standard Test Method E 1921. The value of T_0 is statistically related to the temperature at which fracture toughness specimens from a given weld wire heat exhibited a median fracture toughness of 100 $MPa\sqrt{m}$, which is equivalent to 90 $ksi\sqrt{in}$. The Master Curve method therefore represents an alternative to the “indirect” tests of fracture toughness using drop weight and Charpy V-notch testing per ASME Code Section III, Paragraph NB-2331, which are used to establish values of RT_{NDT}.

Topical Report BAW-2308, Revision 1-A concludes that the use of initial (unirradiated) reference temperature values and appropriate uncertainty terms for certain Linde 80 weld materials, based on Master Curve method and ASME Code Case N-629, provide an acceptable alternate means of predicting irradiation induced shift in fracture toughness when the RT_{NDT}-based irradiation induced shift models of Regulatory Guide 1.99, Revision 2 are employed.

NRC approved use of Topical Report BAW-2308, Revision 1-A subject to certain conditions and limitations delineated in the final safety evaluation attached to Reference 17.

By letter dated February 5, 2007, the PWROG submitted Topical Report BAW-2308, Revision 2, “Initial RT_{NDT} of Linde 80 Weld Materials,” to NRC for review. The intent of Topical Report BAW-2308, Revision 2, was to supplement Topical Report BAW-2308, Revision 1-A, by addressing two of the NRC imposed conditions. NRC has determined that Topical Report BAW-2308, Revision 2 is acceptable for referencing in licensing applications to the extent specified in the final safety evaluation attached to Reference 23.

Branch Technical Position (BTP) 5-3 (Reference 37), formerly known as MTEB 5-2, provides the NRC guidance on Appendices A, G, and H to 10 CFR Part 50 and in 10 CFR 50.61, specifically for older plants designed and built before certain requirements were in force. BTP 5-3 can be used to determine initial RTNDT when insufficient fracture toughness testing data is available to use ASME Code Section III, Paragraph NB-2331, by using the following:

1. If dropweight tests were not performed, but full Charpy V-notch curves were obtained, the nil ductility transition temperature (NDTT) for SA-533 Grade B, Class 1 plate and weld material may be assumed to be the temperature at which 30 ft-lbs was obtained in Charpy Vnotch tests, or 0°F, whichever was higher.
2. If dropweight tests were not performed on SA-508-2 forgings, the NDTT may be estimated as the lowest of the following temperatures:
   a. 60°F,
   b. The temperature of the Charpy V-notch upper shelf
   c. The temperature at which 100 ft-lbs was obtained on Charpy V-notch tests if the upper shelf energy values were above 100 ft-lbs.
3. If transversely-oriented Charpy V-notch specimens were not tested, the temperature at which 50 ft-lbs and 35 mils lateral expansion would have been obtained on transverse specimens may be estimated by one of the following criteria:
   a. Test results from longitudinally-oriented specimens reduced to 65% of their value to provide conservative estimates of values expected from transversely oriented specimens.
   b. Temperatures at which 50 ft-lbs and 35 mils lateral expansion (LE) were obtained on longitudinally-oriented specimens increased 20°F to provide a conservative estimate of the temperature that would have been necessary to obtain the same values on transversely-oriented specimens.
4. If limited Charpy V-notch tests were performed at a single temperature to confirm that at least 41 J (30 ft-lbs) was obtained, that temperature may be used as an estimate of the RTNDT provided that at least 61 J (45 ft-lbs) was obtained if the specimens were longitudinally oriented. If the minimum value obtained was less than 61 J (45 ft-lbs), the RTNDT may be estimated as 11°C (20°F) above the test temperature.

BWRVIP-173-A, Appendix B, Alternative Approach 2 was developed by General Electric (GE) to address SA508, Class 2 forgings when data is scarce or incomplete (Reference 34). It includes a method for determining the initial RTNDT for plates and forgings with limited measured data. The approach for vessel plate and forging materials is as follows:

(1) Derive a nil-ductility transition temperature (NDTT) value as equal to the longitudinal Charpy V-notch 35 ft-lb transition temperature.

(2) Operate on the lowest longitudinal Charpy V-notch data point (ft-lbs) to obtain at least 50 ft-lbs transition temperature by adding 2°F per ft-lb, or by plotting a curve (ft-lbs vs. temperature) where possible. If no transverse Charpy V-notch data are available, an adjustment must be made to convert from longitudinal to the transverse 50 ft-lbs transition temperature. BTP 5-3 suggests a 20°F shift, whereas GE recommends a 30°F shift. The NRC has accepted both longitudinal to transverse temperature shift methods as being conservative.

(3) RTNDT is the higher of the NDTT from (1), or the transverse Charpy V-notch 50 ft-lbs transition temperature value from (2) minus 60°F.

NRC has determined that BWRVIP-173-A, Appendix B, Alternative Approach 2 is acceptable for referencing in licensing applications to the extent specified in the final safety evaluation attached to Reference 34.

ASME Section XI Appendix G provides guidance for translating the value of RT_{NDT} into a K value, representative of the material's resistance to fracture. Normal operation and hydrostatic test pressure/temperature operating limits which satisfy the requirements of 10 CFR 50 Appendix G are established on the basis of linear-elastic fracture mechanics theory, such that thermal and pressure stresses will not result in combined stresses in excess of the material's resistance to fracture (K). Because the normal operating temperature of the reactor vessel is well above the RT_{NDT} of the limiting reactor vessel beltline material, brittle fracture during normal operation is not considered to be a credible mode of failure.

The allowable pressures are revised periodically according to the schedule in the reactor vessel surveillance program. The revised curves are based upon the experimentally determined fluence from the last analyzed capsule, and a conservative fluence projection for the next scheduled capsule withdrawal. The use of an RT_{NDT} which includes the projected change in RT_{NDT} due to irradiation provides additional conservatism for the non-irradiated components of the reactor coolant system.

Virginia Power has been a member of the Babcock and Wilcox Owner's Group (B&WOG) Reactor Vessel Working Group (RVWG). Surry Units 1 and 2 are participants in the RVWG's Master Integrated Reactor Vessel Surveillance Program (MIRVSP) (Reference 8). The program integrates (a) the plant specific reactor vessel surveillance programs of the participants, (b) the existing supplemental B&W Owners Group irradiation capsules, (c) additional supplemental irradiation capsules to assure the availability of high fluence and thermal annealing data for the participants' reactor vessels, (d) existing test reactor irradiation data sources, and (e) provisions for additional test reactor irradiation data sources. The objectives of the MIRVSP are as follows:

1. Provide a unified power reactor data base for Linde 80 welds necessary to perform the analysis required by 10 CFR 50, Appendix G for materials that may exhibit < 50 ft-lb Charpy upper-shelf energy.
2. Maximize the effectiveness of data sharing among participants to assure that required data is available to all participants for current and extended plant operation.
3. Provide the materials, specimens, irradiation capsules, and power reactor irradiation sites required to obtain data that can be used to evaluate the thermal annealing process.
4. Minimize testing of redundant capsules (those which do not provide useful information) in existing plant-specific RVSP's to ensure optimum utilization of data sources.
5. Simplify the licensing process by providing a single document that covers the RVSP integration and capsule withdrawal schedules and which can be referenced in each utility's design documentation.

The MIRVSP does not reduce the number of required capsules in the plant-specific programs, nor does it eliminate the requirement that an acceptable reactor vessel fluence monitoring program be maintained. An integrated program must meet the criteria enumerated in 10 CFR 50, Appendix H, Paragraph III.C.

These criteria and considerations are satisfied by the MIRVSP approach (Reference 9). The Surry 1 and 2 plant-specific surveillance capsule withdrawal schedules presented in Tables 4.1-12 and 4.1-13 are consistent with the guidelines of the MIRVSP as described above. Standby Capsules U, S, and Y (Unit 1) and T and Z (Unit 2) are available to satisfy potential fluence monitoring requirements during the 20-year license renewal and subsequent license renewal (SLR) periods.

4.1.7.2 Flux Activation Measurements in the Irradiation Samples

The Surry Units 1 & 2 surveillance program capsules contain passive neutron flux monitors made of U-238, Np-237, Co-Al, Cu, Ni, Cadmium-shielded Co-Al, and Fe. The iron (for Surry Unit 2), nickel, copper, and cobalt-aluminum monitors, in wire form, are placed in holes drilled in spacers at several axial levels within the capsules. For Surry Unit 1, the test specimens also serve as iron dosimeters. Cadmium-shielded neptunium and uranium fission monitors are accommodated within a dosimeter block located near the center of the capsule.

The use of passive monitors does not yield a direct measure of the energy dependent flux level at the point of interest. Rather, the activation or fission process is a measure of the integrated effect that the time- and energy-dependent neutron flux has on the target material over the course of the irradiation period. An accurate assessment of the average neutron flux level incident on the various monitors may be derived from the activation measurements only if the irradiation parameters are well known. In particular, the following variables are of interest:

- The operating history of the reactor
- The energy response of the monitor
- The neutron energy spectrum at the monitor location
- The physical characteristics of the monitor

The specific activity of each of the monitors is determined using established ASTM procedures. Following sample preparation, the activity of each monitor is determined using contemporary gamma-ray spectroscopy techniques. The overall standard deviation of the measured data is a function of the precision of sample weighing, the uncertainty in counting, and the acceptable error in detector calibration.

Having the measured specific activities, the operating history of the reactor, and the physical characteristics of the sensors, reaction rates referenced to full power operation are determined from the following equation::

$$R = \frac{A}{N_0 F Y \sum_{j=1}^{n} \frac{P_j}{P_{ref}} C_j (1 - e^{-\lambda t_j}) e^{-\lambda t_d}}$$

where:

R	=	sensor reaction rate averaged over the irradiation period and referenced to operation at a core power level of Pref (rps/atom)
No	=	number of target element atoms per gram of sensor (atom/gram)
A	=	measured specific activity
F	=	weight fraction of the target isotope in the target material
Y	=	number of product atoms produced per reaction
n	=	total number of monthly intervals comprising the irradiation period
Pj	=	average core power level during irradiation period j (MW)
Pref	=	maximum or reference core power level of the reactor (MW)
l	=	decay constant of the product isotope (s-1)
tj	=	length of irradiation period j (s)
td	=	decay time following irradiation period j (s)

C_j = Calculated ratio of ø(E > 1.0 MeV) during irradiation period j to the time-weighted average ø(E > 1.0 MeV) over the total irradiation period.

The computed full power reaction rates form a suitable basis for comparison with the results of neutron transport calculations described in Section 4.1.7.3

4.1.7.3 Calculation of Integrated Fast Neutron (E Greater than 1.0 Mev) Flux at the Irradiation Samples

Knowledge of the neutron environment within the pressure vessel-surveillance capsule geometry is required as an integral part of LWR pressure vessel surveillance programs for two reasons. First, in the interpretation of radiation-induced property changes observed in materials test specimens, the neutron environment (fluence, flux) to which the test specimens were exposed must be known. Second, in relating the changes observed in the test specimens to the present and future condition of the reactor pressure vessel, a relationship between the environment at various positions within the reactor vessel and that experienced by the test specimens must be established. The former requirement is normally met by employing a combination of rigorous analytical techniques and measurements obtained with passive neutron flux monitors contained in each of the surveillance capsules. The latter information, on the other hand, is derived solely from analysis.

This section describes a discrete ordinates Sn transport analysis performed for the Surry Units 1 & 2 reactor to determine the fast neutron (E > 1.0 Mev) flux and fluence as well as the neutron energy spectra within the reactor vessel and surveillance capsules; and, in turn, to develop data for use in relating neutron exposure of the pressure vessel to that of the surveillance capsules.

A plan view of the Surry reactor geometry at the core midplane is shown in Figure 4.1-2. Eight irradiation capsule holders attached to the thermal shield are included in the design to support the reactor vessel surveillance program (References 4 & 5). The capsules were originally located at 45°, 55°, 65°, 165°, 245°, 285°, 295°, and 305° relative to the major axis at 0°.

An axial and plan view of a single surveillance capsule attached to the thermal shield is shown in Figure 4.1-1. The stainless steel specimen container is 1-inch square and approximately 3 feet in height. The containers are positioned axially such that the specimens are centered on the core midplane, thus spanning the central 3 feet of the 12-foot high reactor core.

From a neutronic standpoint, the surveillance capsule structures are significant. In fact, they have a marked impact on the distributions of neutron flux and energy spectra in the water annulus between the thermal shield and the reactor vessel. Thus, in order to properly ascertain the neutron environment at the test specimen locations, the capsules themselves must be included in the analytical model. Use of at least a two-dimensional computation is, therefore, mandatory.

Fast neutron fluence (E > 1.0 MeV) analyses (References 18 & 19) were performed in support of the transition to integral fuel burnable absorber (IFBA) for Surry Units 1 and 2, and the removal of flux suppression inserts for Unit 1. The neutron fluence analyses are valid to a cumulative core exposure of 48 Effective Full Power Years for both units. Core power distributions for use in the plant specific fluence evaluations for Surry Units 1 and 2 are derived from measured assembly and cycle burnups for operating cycles 1 through 19 for Unit 1, and cycles 1 through 18 for Unit 2. The fluence evaluations reflect the low leakage fuel management strategies employed in previous operating cycles, and also include the rated thermal power uprate from 2441 MWt to 2546 MWt. Future operating cycles were assumed to be representative of reload core designs with integral fuel burnable absorber and without flux suppression inserts. A capacity factor of 95% was assumed to be representative of future operation.

The primary tool used in the determination of the flux and fluence exposure to the reactor vessel and surveillance capsules is the two-dimensional discrete ordinates transport code DORT (Reference 2). The neutron fluence analysis is divided into seven tasks: (1) generation of the neutron source, (2) development of the DORT geometry models, (3) calculation of the macroscopic material cross sections, (4) synthesis of the results, and (5-7) estimation of the calculational bias, the calculational uncertainty, and the final fluence.

The time-averaged space and energy-dependent neutron sources were calculated for the previous cycles explicitly modeled in the fluence evaluations. The effects of burnup on the spatial distribution of the neutron source were accounted for by calculating the cycle average fission spectrum for each fissile isotope on an assembly-by-assembly basis, and by determining the cycle-average specific neutron emission rate. This data was then used with the normalized time weighted average pin-by-pin relative power density (RPD) distribution to determine the space and energy-dependent neutron source. The azimuthally averaged, time averaged axial power shape in the peripheral assemblies was used with the fission spectrum of the peripheral assemblies to determine the neutron source for the DORT analyses.

The BUGLE-93 (Reference 3) cross section library was used for the neutron fluence analyses. The BUGLE-93 library is an ENDF/B-VI based data set produced specifically for light water reactor applications.

The system geometry is approximated using a combination of two-dimensional DORT models. The radial plane DORT model, (R,θ), encompasses a plane bounded radially by the center of the core and extending through the reactor vessel wall and into the concrete shield, and azimuthally by the major axis at 0° and the adjacent 45° radius. The vertical plane DORT model, (R, Z), encompasses a plane bounded axially by the upper and lower grid plates, and radially by the center of the core and a vertical line within the concrete shield. For the Unit 1 cycles where flux suppression inserts were modeled, the DORT models were further refined into multiple axial regions due to the asymmetric flux distribution.

The cross sections, geometry, and appropriate neutron sources were combined to create a set of DORT neutron transport models (R,θ) and (R, Z) for the analysis. Each (R,θ) and (R, Z) DORT run utilized a cross section Legendre expansion of three (P_3), at least forty-eight directions (S_8), with the appropriate boundary conditions. The DORT analyses produce two sets of two-dimensional flux distributions, one for a vertical plane (R, Z), and one for the radial plane (R,θ), for each set of dosimetry.

Under the assumption that the three-dimensional neutron flux is a separable function, both two-dimensional data sets were mathematically combined to estimate the flux at all three-dimensional points (R,θ,Z) of interest.

The neutron fluence evaluations documented in References 18 and 19 were performed by Framatome ANP with acceptable methods that are in compliance with NRC Regulatory Guide 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.* Compliance with NRC Regulatory Guide 1.190 requires that fluence values must be unbiased best-estimate calculations with a well-defined uncertainty. The neutron fluence analyses of References 18 and 19 meet these conditions, with a calculational uncertainty (1σ) of less than or equal to 15 percent.

The fluence values used in References 18 and 19 have been determined to conservatively bound the more recently developed fluence analyses that explicitly consider the effects of a Measurement Uncertainty Recapture (MUR) uprated core power level (2597 MWth).

The neutron fluence evaluations documented in References 32 and 33 were performed by Westinghouse Electric Company. The fluence projections from Framatome ANP are more conservative than the Westinghouse fluence projections.

The most recent pressure vessel fluence calculation for Surry Units 1 and 2 is documented in Reference 38, where a discrete ordinates Sn transport calculation was performed for the Surry Units 1 and 2 reactors to determine the neutron radiation environment within the traditional and extended beltline region of the reactor pressure vessel. The neutron transport methodology followed the guidance of the NRC Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence” (March 2001). The methods used to develop the calculated pressure vessel fluence are consistent with the NRC-approved methodology described in Westinghouse Report WCAP-14040-A, Revision 4 (Reference 39).

In performing the fast neutron (E > 1.0 MeV) exposure calculations for the Surry Units 1 and 2 reactor vessels, a series of fuel-cycle-specific forward transport calculations were carried out using the two-dimensional/one-dimensional flux synthesis technique to obtain synthesized three-dimensional neutron flux distributions in Reference 38. All of the transport calculations supporting the analyses were carried out using the DORT discrete ordinates code (Reference 40) and the BUGLE-96 cross-section library (Reference 41). The BUGLE-96 library provides a coupled 47-neutron, 20-gamma-ray group cross-section data set based on ENDF/B-VI, produced specifically for light-water reactor applications. In these analyses, anisotropic scattering was treated with a P5 Legendre expansion and angular discretization was modeled with an S16 order of angular quadrature. Energy- and space-dependent core power distributions, as well as system operating temperatures, were treated on a fuel-cycle-specific basis. In Reference 38, fast neutron

(E > 1.0 MeV) fluence projections at 54, 68, and 72 Effective Full Power Years are provided for the pressure vessel materials at the traditional and extended beltline regions.

4.1.7.4 Measurement of the Initial RT_{NDT} of the Reactor Pressure Vessel Baseplate and Forgings Material

The temperature at which a material transitions from failure by ductile tearing to failure by brittle fracture is known as the Reference Temperature for the Nil Ductility Transition (RT_{NDT}). The unirradiated RT_{NDT} is the higher of (a) the nil-ductility transition temperature (NDTT or T_{NDT}) as determined by drop weight test, or (b) the temperature at which Charpy test specimens oriented normal to the major working direction exhibit at least 50 ft-lb of absorbed energy and 35 mils of lateral expansion, minus 60°F. The unirradiated (or initial) NDTT for the pressure vessel baseplate and forged materials was determined in accordance with ASTM requirements in place at the time of the original design and licensing of Surry Units 1 and 2. Drop weight and Charpy V-notch testing was performed in accordance with the then-applicable versions of ASTM E208 and ASTM E23, respectively.

The quantity identified as T_{NDT} in Tables 4.1-14 and 4.1-15 is defined in the version of ASTM E208 applicable at the original design and licensing of Surry Units 1 and 2 as “the temperature at which a specimen is broken in a series of tests in which duplicate no-break performance occurs at 10°F higher temperature.”

Tables 4.1-14 and 4.1-15 also provide the unirradiated RTNDT values as determined by NB-2331 of Section III of the ASME B&PV Code or one of the 3 alternative methods for determining the RTNDT listed below.

- Topical Report BAW-2308
- Branch Technical Position (BTP) 5-3, Revision 2
- EPRI Report BWRVIP-173-A, Appendix B, Alternative Approach 2 (GE Method)

As part of the Westinghouse surveillance program referred to above, Charpy V-notch impact tests, tensile tests, and fracture mechanics specimens are taken from the core region plates and forgings, and core region weldments including heat-affected-zone material. The test locations are similar to those used in the tests by the fabricator at the plate mill.

The uncertainties of measurement of the baseplate NDTT are:

1. Differences in Charpy V-notch ft-lb values at a given temperature between specimens.
2. Variation of impact properties through plate thickness.

The fracture toughness technology for pressure vessels and correlation with service failures based on Charpy V-notch impact data is based on the minimum data points. The Charpy V-notch data consists of multiple tests by the material supplier, the fabricator, and by Westinghouse as part of the surveillance program. In accordance with ASME Code Section III, Subarticle NB-2331, Paragraph (a)(4), only the minimum data points at each Charpy V-notch test temperature were used as input.

There are quantitative differences between the NDTT measurements at the surface, one-quarter thickness (1/4-T), or center of a plate. The NDTT from 1/4-T to the center in heavy plates is observed to vary from improvement in the NDTT to increases up to 85°F. The NDTT at the surface is measured to be as much as 85°F lower than at 1/4-T.

The 1/4-T location is considered conservative since the enhanced metallurgical properties of the surface are not used for the determination of NDTT. In addition, the limiting NDTT for the reactor vessel after operation is based on the NDTT shift due to irradiation. The design value of NDTT after irradiation is assessed at the tip of an assumed quarter-thickness flaw for purposes of establishing Reactor Coolant System (RCS) pressure/temperature operating limits.

Data have been accumulated on the variation of NDTT across heavy section steels at Westinghouse, Nuclear Energy Systems. Similarly, an evaluation of properties of pressure vessel steels in plates 6 to 12 inches thick has been sponsored by the Pressure Vessel Research Committee. Data show NDTT differences between 1/4-T and center of less than 20°F. The criterion of using NDTT + 60°F at the 1/4-T location without taking advantage of the enhanced properties at the surface of reactor vessel plates is conservative.

To assess any possible uncertainties in the consideration of NDTT shift for welds, heat-affected zones, and base metals, test specimens of these three material types are included in the reactor vessel surveillance program.

Additional information on the surveillance programs is available in References 4 and 5, which were submitted to the NRC by Vepco letter dated January 23, 1978. The results of the surveillance programs are documented in References 6 and 20 for Unit 1 Capsules V and X respectively, and References 7 and 21 for Unit 2 Capsules V and Y respectively. Additional information concerning upper shelf energy and chemical composition is reported in References 10, 11, 12, 35, and 36. Although Reference 12 considered higher cumulative core burnups (effective full power years, EFPY) than the values assumed in the pressure/temperature limits and the low temperature overpressure protection system (LTOPS) enable temperature, the then-existing Technical Specification bases were considered conservative, and were not revised to take credit for the additional margin. References 24 and 25 extended the cumulative core burnup applicability limit for the pressure/temperature limits and low temperature overpressure protection system (LTOPS) enabling temperature to 48 EFPY, and included consideration of Measurement Uncertainty Recapture (MUR) uprate. Reference 44 extended the cumulative core burnup applicability limit for the pressure/temperature limits and low temperature overpressure protection system (LTOPS) enabling temperature to 68 EFPY.

4.1 REFERENCES

1. A. L. Lowe, Jr., *Reactor Pressure Vessel and Surveillance Program Materials Licensing Information for Surry Units 1 and 2,* BAW-1909, March 1986.

2. Rutherford, M. A., Hassan, N. M. et al., Eds., *DORT, Two Dimensional Discrete Ordinates Transport Code,* BWNT-TM-107, Framatome ANP, Lynchburg, Virginia, May 1995.

3. Ingersoll, D. T., et al., *BUGLE-93, Production and Testing of the VITAMIN-B6 Fine Group and the BUGLE-93 Broad Group Neutron/photon Cross-Section Libraries Derived from ENDF/B-VI Nuclear Data,* ORNL-DLC-175, Radiation Safety Information Computational Center, Oak Ridge National Laboratory, Oak Ridge, Tennessee, April 1994.

4. *Virginia Electric and Power Company, Surry Unit No. 1, Reactor Vessel Radiation Surveillance Program*, WCAP-7723.

5. *Virginia Electric and Power Company, Surry Unit No. 2, Reactor Vessel Radiation Surveillance Program*, WCAP-8805.

6. S. E. Yanichko, et al., *Analysis of Capsule V from the Virginia Electric and Power Company, Surry Unit 1, Reactor Vessel Radiation Surveillance Program*, WCAP-11415, dated February 1987.

7. S. E. Yanichko, et al., *Analysis of Capsule V from the Virginia Electric and Power Company, Surry Unit 2, Reactor Vessel Radiation Surveillance Program,* WCAP-11499, dated June 1987.

8. L. S. Harbison, *Master Integrated Reactor Vessel Surveillance Program*, BAW-1543, Revision 4, dated February 1993. Also Supplement 5 dated December 2003.

9. Letter from NRC to J. S. Holm (Framatome ANP), *Final Safety Evaluation for Babcock and Wilcox Owners Group Topical Report BAW-1543(NP), Revision 4, Supplement 5, 'Supplement to the Master Integrated Reactor Vessel Surveillance Program' (TAC No. MC1762),* dated May 16, 2005.

10. M. J. DeVan, et al: *Response to Closure Letters to Generic Letter 92-01, Revision 1,* BAW-2222, dated June 1994.

11. Letter from L. N. Hartz, (Virginia Power) to USNRC, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Supplement to Response to NRC Request for Additional Information (RAI) on Generic Letter 92-01, Revision 1, Supplement 1,* Serial No. 99-034, dated February 24, 1999.

12. Letter from L. N. Hartz to USNRC, *Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Surry Power Station Units 1 and 2, Evaluation of Reactor Vessel Materials Surveillance Data,* Serial No. 99-452A, dated November 19, 1999.

13. Letter from NRC to Virginia Electric and Power Company, dated October 1, 2002, Docket Nos. 50-280 and 50-281, *Safety Evaluation by the Office of Nuclear Reactor Regulation, Inservice Inspection Relief Requests SR-27, SR-28, SR-32, and SR-33.*

14. Framatome ANP Document No. 33-1011607, *Surry Unit 1 Replacement Reactor Vessel Closure Head Design Report.*

15. Framatome ANP Document No. 51-5026905, *Surry 1 RV Closure Head Report of Reconciliation.*

16. Mitsubishi Heavy Industries, LTD., Design Report DG KCS-03-0003, *Dominion Generation, Surry Power Station Unit 2, Design Report (RVCH),* Rev. 3.

17. Framatome ANP Topical Report BAW-2308, Revision 1-A, *Initial* RT_{NDT} *of Linde 80 Weld Materials,* dated August 2005.

18. Framatome ANP Report 32-5068629-00, *Surry Unit 1 Updated Fluence Calculation - Cycles 1 to 19,* July 2005.

19. Framatome ANP Report 32-5070607-00, *Surry Unit 2 Fluence Calculation - Cycles 1 to 18,* September 2005.

20. Framatome Report BAW-2324, *Analysis of Capsule X Virginia Power Surry Unit 1 - Reactor Vessel Material Surveillance Program,* April 1998.

21. Westinghouse WCAP-16001, Revision 0, *Analysis of Capsule Y from Dominion Surry Unit 2 Reactor Vessel Radiation Surveillance Program,* February 2003.

22. Framatome ANP Report BAW-2494, Revision 1, *Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Surry Units 1 and 2 for Extended Life through 48 Effective Full Power Years,* September 2005.

23. Framatome ANP Topical Report BAW-2308, Revision 2-A, *Initial* RT_{NDT} *of Linde 80 Weld Materials*, March 24, 2008.

24. Letter from L. N. Hartz (Dominion) to NRC, *Virginia Electric and Power Company (Dominion), Surry Power Station Units 1 and 2, License Amendment Request, Measurement Uncertainty Recapture Power Uprate*, Serial No. 09-223, January 27, 2010.

25. Letter to D. A. Heacock (Dominion) from K. Cotton (USNRC), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Measurement Uncertainty Recapture Power Uprate (TAC Nos. ME3293 and ME3294)*, Dominion Serial No. 10-580, dated September 24, 2010.

26. Letter from J. A. Price to USNRC, Virginia Electric and Power Company (Dominion), *Surry Power Station Units 1 and 2, Revised Reactor Vessel Materials Surveillance Capsule Withdrawal Schedules - UFSAR Change*, Serial No. 09-507, dated October 26, 2009.

27. Letter from J. A. Price to USNRC, Virginia Electric and Power Company (Dominion), *Surry Power Station Units 1 and 2, Revised Reactor Vessel Materials Surveillance Capsule Withdrawal Schedules - UFSAR Change*, Serial No. 09-507A, dated September 13, 2010.

28. Letter from J. A. Price to USNRC, Virginia Electric and Power Company (Dominion), *Surry Power Station Units 1 and 2, Revised Reactor Vessel Materials Surveillance Capsule Withdrawal Schedules - UFSAR Change*, Serial No. 10-721, dated January 3, 2011.

29. Letter to D. A. Heacock (Dominion) from K. Cotton (USNRC), S*urry Power Station, Unit Nos. 1 and 2 - Safety Evaluation for Revision to Reactor Vessel Surveillance Capsule Withdrawal Schedule (TAC NOS. ME4133 and ME4134)*, Serial No. 11-064, dated January 31, 2011.

30. Letter from J. A. Price to USNRC, *Surry Power Station Units 1 and 2, License Amendment Request Revised Cumulative Core Burnup Applicability Limit for Heatup and Cooldown Curves, low Temperature Overpressure Protection System (LTOPS) Setpoint and LTOPS Enable Temperature,* dated May 6, 2010.

31. Letter from Karen Cotton to (USNRC) to D. A. Heacock, *Surry Power Station Unit Nos. 1 and 2, - Issuance of Amendments Regarding Reactor Vessel Heatup and Cooldown Curves For 48 effective Full-Power Years (TAC Nos. ME3920 and ME3921),* Serial No. 11-322, dated May 31, 2011.

32. CN-REA-08-74, *Pressure Vessel Neutron Fluence Evaluation to Support the MUR for Surry Unit 1*, July 29, 2009.

33. CN-REA-08-75, *Pressure Vessel Neutron Fluence Evaluation to Support the MUR for Surry Unit 2*, July 30, 2009.

34. BWRVIP-173-A: *BWR Vessel and Internals Project: Evaluation of Chemistry Data for BWR Vessel Nozzle Forging Materials.* EPRI, Palo Alto, CA: 2011. 1022835.

35. *Pressurized Water Reactor Owners Group (PWROG) Report PWROG-16045-NP, Revision 0, Determination of Unirradiated RTNDT and Upper-Shelf Energy Values of the Surry Units 1 and 2 Reactor Vessel Materials,* March 2017.

36. Westinghouse WCAP-18242-NP, Revision 2, *Surry Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal,* July 2018.

37. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Chapter 5 of LWR Edition, Branch Technical Position 5-3, “Fracture Toughness Requirements,” Revision 2, U.S. Nuclear Regulatory Commission, March 2007.

38. Westinghouse Report WCAP-18028-NP, Revision 1, *Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 & 2,* April 2018.

39. Westinghouse Report WCAP-14040-A, Revision 4, *Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,* May 2004.

40. RSICC Computer Code Collection CCC-650, DOORS 3.2: *One-, Two- and Three Dimensional Discrete Ordinates Neutron/Photon Transport Code System*, Oak Ridge National Laboratory, Oak Ridge, Tennessee, April 1998.

41. RSICC Data Library Collection DLC-185, BUGLE-96: Coupled 47 Neutron, 20 *Gamma-Ray Group Cross Section Library Derived from ENDF/B-VI for LWR Shielding and*

Pressure Vessel Dosimetry Applications, Oak Ridge National Laboratory, Oak Ridge, Tennessee, March 1996

42. Areva Topical Report BAW-2178NP, Supplement 1, Revision 0, *Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels C & D Service Loads*, December 2017.

43. Areva Topical Report BAW-2192NP, Supplement 1, Revision 0, *Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels A & B Service Loads*, December 2017.

44. Westinghouse WCAP-18243-NP, Revision 2, *Surry Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation,* July 2018.

Table 4.1-1
REACTOR COOLANT SYSTEM PRESSURES

	Pressure (psig)
Hydrostatic test pressure	3107
Design pressure	2485
Safety valves (open)	2485
High-pressure trip setpoint	2370
Power relief valves (open)	2335
High-pressure alarm	2310
Pressurizer spray valves (open)	2260
Operating pressure (at pressurizer)	2235
Low-pressure alarm	2210
Low-pressure trip setpoint	1885

Table 4.1-2
REACTOR VESSEL DESIGN DATA

Design pressure	2485 psig
Operating pressure	2235 psig
Hydrostatic test pressure	3107 psig
Design temperature	650°F
Overall height of vessel and closure head	40 ft. 5 in.
Water volume, with core and internals in place	Approximately 3720 ft^3
Thickness of insulation, vessel & flange	3 in. (nominal)
Thickness of insulation, reactor closure head dome	5 in.[a] (nominal)
Number of reactor closure head studs	58
Diameter of reactor closure head studs	6 in.
I.d. of flange	149.7205 in. (Unit 1) 149.563 in. (Unit 2)
O.d. of flange	184 in.
I.d. at shell	157 in.
Inlet nozzle i.d.	Tapered 27.437 to 35.406 in.
Outlet nozzle i.d.	28.97 in. straight
Clad thickness, minimum	0.1968 in. (Unit 1) 0.125 in. (Unit 2)
Lower head thickness, minimum	5 in.[b]
Vessel belt-line thickness, minimum	7.875 in.[b]
Closure head thickness, minimum	6.286 in.[c] (Unit 1) 6.188 in.[b] (Unit 2)
Reactor coolant inlet temperature (100% power)	536.7 - 542.9°F
Reactor coolant outlet temperature (100% power)	603.3 - 609.1°F
Reactor coolant flow	(100.8 - 101.6) x 10^6 lb/hr

a. Some areas at tangent points are less than 5 in.
b. Not including 0.125-inch minimum thickness of cladding.
c. Not including 0.1968 minimum thickness of cladding.

Table 4.1-3
PRESSURIZER AND PRESSURIZER RELIEF TANK DESIGN DATA

Pressurizer	
Design pressure	2485 psig
Operating pressure	2235 psig
Hydrostatic test pressure	3107 psig
Design/operating temperature	680/653°F
Water volume, 100% power	780 ft^3 [a]
Steam volume, 100% power	520 ft^3
Surge line nozzle diameter	14 in.
Shell i.d.	84 in.
Minimum shell thickness	4.1 in.
Minimum clad thickness	3/16 in.
Electric heaters capacity (total)	1300 kW
Heatup rate of pressurizer using heaters only	55 °F/hr
Power-operated pressurizer relief valves	
Number	2
Opening pressure	2335 psig
Capacity, saturated steam/valve	
(maximum)	210,000 lb/hr
(nominal)	179,000 lb/hr
Pressurizer safety valves	
Number	3
Opening pressure	2485 psig
ASME rated flow	293,330 lb/hr
Pressurizer Relief Tank	
Design pressure	100 psig
Rupture disk (or safety head) relief pressure	100 psig
Design temperature	340°F
Normal water temperature	120°F
Standby water volume	900 ft^3
Total volume	1300 ft^3
Rupture disk (or safety head) total relief capacity	900,000 lb/hr
Number of rupture disks	2

a. Contents at 60% of net internal volume = 100% power.

Table 4.1-4
STEAM GENERATOR DESIGN DATA (PER STEAM GENERATOR)

Number of steam generators per unit	3	
Design pressure, reactor coolant/steam	2485/1085 psig	
Reactor coolant hydrostatic tested pressure (tube side)	3107 psig	
Hydrostatic test pressure (shell side)	1356 psig	
Design temperature, reactor coolant/steam	650/600°F	
Reactor coolant flow	(33.6 - 33.9) $\times 10^6$ lb/hr	
Total heat transfer surface area	51,500 ft^2	
Heat transferred at 100% load	2968 $\times 10^6$ Btu/hr	
Steam conditions at 100% load, outlet nozzle		
Steam flow	(3.86 - 3.87) $\times 10^6$ lb/hr	
Steam temperature	(509.2 - 518.3)°F	
Steam pressure	738.9 - 800.3 psia	
Feedwater temperature at 100% load	452.0°F	
Overall height	67 ft. 8 in.	
Shell o.d., upper/lower	178/135 in.	
Shell thickness	2.9 in.	
Number of U-tubes	3342	
U-tube o.d.	0.875 in.	
Tube wall thickness (average)	0.050 in.	
Number of manways/i.d.	6/16 in.	
Number of handholes/i.d.	6/6 + 2/2 in.	
	At 2652 MWt [a, b]	At Zero Power [b]
Reactor coolant water volume	1077 ft^3	1077 ft^3
Primary-side fluid heat content	28.4 $\times 10^6$ Btu	27.5 $\times 10^6$ Btu
Secondary-side water volume	1688.5 ft^3	3581.8 ft^3
Secondary-side steam volume	3870 ft^3	1976.7 ft^3
Secondary-side fluid heat content	45.53 $\times 10^6$ Btu	95.0 $\times 10^6$ Btu

a. 2652 MWt represents the steam generator design performance capability and is not intended to indicate reactor thermal power rating.

b. The parameter values listed in this section of the table represent initial plant design and operating information. These values are not intended to be updated in the future.

Table 4.1-5
REACTOR COOLANT PUMP DESIGN DATA

Number of pumps	3
Design pressure/operating pressure	2485/2235 psig
Hydrostatic test pressure	3107 psig
Design temperature (casing)	650°F
Revolutions per min at nameplate rating	1170
Design head	280 ft
Design capacity/pump	88,500 gpm
Flow at 542.9°F/pump	33.6×10^6 lb/hr
Seal-water injection/pump	8 gpm
Seal-water return/pump	2.5 gpm
Pump discharge nozzle i.d.	27.5 in.
Pump suction nozzle i.d.	31 in.
Overall pump assembly height	25 ft. 5 in.
Pump casing water volume/pump	56 ft^3
Thermal barrier water volume/pump	25 ft^3
Approximate pump-motor moment of inertia	70,000 lb/ft^2

	North Anna Motors	Original Surry Motors
Motor data Type	ac induction single speed, air cooled	ac induction single speed, air cooled
Voltage	4000V	4000V
Insulation class	B thermolastic epoxy	B thermolastic epoxy
Phase	3	3
Frequency	60 Hz	60 Hz
Starting		
Input (hot reactor coolant)	5163 kW	4375 kW
Input (cold reactor coolant)	6839 kW	5740 kW
Power (nameplate)	7000 hp	6000 hp

Table 4.1-6
REACTOR COOLANT PIPING DESIGN DATA

Design/operating pressure	2485/2235 psig
Hydrostatic test pressure (cold)	3107 psig
Design temperature (except pressurizer surge line)	650°F
Design temperature (pressurizer surge line)[b]	680°F
Reactor inlet piping i.d.	27.5 in.
Reactor inlet piping, nominal thickness	2.375 in.
Reactor outlet piping, i.d.	29 in.
Reactor outlet piping, nominal thickness	2.50 in.
Coolant pump suction piping, i.d.	31 in.
Coolant pump suction piping, nominal thickness	2.625 in.
Pressurizer surge line piping, nominal diameter[a]	12 in.
Pressurizer surge line piping, nominal thickness	1.125 in.
Water volume (all three loops)	1041 ft^3

a. Surge line fitted with a 14 in./12 in. adapter at the pressurizer.

b. Pressurizer surge line is also evaluated for the effect of thermal stratification and stripping per NRC Bulletin 88-11, dated December 20, 1988 (Appendix 15A, References 37 & 38).

Table 4.1-7
LOOP STOP VALVES

Design/normal operating pressure	2485/2235 psig
Hydrostatic test pressure shop/loop	5400/3107 psig
Design temperature	650°F
Hot-leg valve size, nominal	29 in.
Cold-leg valve size, nominal	27.50 in.
Open/close travel time	210 sec

Table 4.1-8
THERMAL AND LOADING CYCLES

Transient Conditions	Design Cycle[a]
Heatup at 100°F/hr	200
Cooldown at 100°F/hr	200
Loading at 5% of full power per min (15 to 100% equals one cycle)	18,300
Unloading at 5% of full power per min (100 to 15% equals one cycle)	18,300
Step load increase of 10% full power (but not to exceed full power)	2000
Step load decrease of 10% of full power	2000
Step load reduction from 100 to 50% load	200
Reactor trip from full power	400
Hydrostatic test pressure, 3107 psig at 100°F	5
Hydrostatic test pressure, 2485 psig at 400°F	40

Steady-state fluctuations - the reactor coolant average temperature for purposes of design will be assumed to increase and decrease a maximum of 6°F in 1 minute. The corresponding reactor coolant pressure variation will be less than 100 psig. It is assumed that an infinite number of such fluctuations will occur.

a. Estimated for equipment design purposes (using the original license period of 40 years as a basis) and not intended to be an accurate representation of actual transients, or to reflect actual operating experience. These estimates have been retained for the 80-year subsequent renewed operating license period.

Table 4.1-9
REACTOR COOLANT SYSTEM - CODE REQUIREMENTS

Component	Codes
Reactor vessel [a]	ASME III[b]Class A
Control rod drive mechanism housing	ASME III[b] Class A
Unit 1 control rod drive mechanism head adapter plugs	ASME III[b] Class 1
Steam generators	
Tube side	ASME III[b] Class A
Shell side[c]	ASME III[b] Class C
Reactor coolant pump casing	No code (design per ASME III - Article 4)
Pressurizer	ASME III[b] Class A
Pressurizer relief tank	ASME III[b] Class C
Pressurizer safety valves	ASME III[b]
Reactor coolant piping	USAS B31.1[d]
System valves, fittings, and piping	USAS B31.1d,e

a. Unit 1 Reactor Vessel Closure Head replaced with closure head designed to French Construction Code (R-CCM) 1993 Edition with 1st Addenda June 1994, 2nd Addenda June 1995, 3rd Addenda June 1996, and Modification Sheets FM 797, 798, 801, 803, 804, 805, 806, and 807. The sizing calculations and the stress and fatigue analysis were performed to ASME B&PV Code, Section III, 1995 Edition 1996 Addenda. The Design Report certified that the Unit 1 closure head meets the design requirements and stress limits for the ASME B&PV Code, Section III, 1968 Edition through Winter 1968 Addenda

b. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

c. The shell side of the steam generator conforms to the requirements for Class A vessels and is so stamped as permitted under the rules of Section III.

d. USAS B31.1 Code for Pressure Piping.

e. A reanalysis of the pressurizer surge line to account for the effect of thermal stratification and striping was performed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III 1986 with addenda thru 1987 incorporating high cycle fatigue as required by NRC Bulletin 88-11, dated December 20, 1988.

Table 4.1-10
CAPSULE SPECIMEN DATA, UNIT 1

	Number of Specimens		
	Charpy	Tensile	WOL
Material - Type I Capsules (S, U, W, and Y)			
Plate #1 (high NDT)	10	2	3
Plate #2	10	2	3
Correlation monitor	8	-	-
Material - Type II Capsules (T, V, X, and Z)			
Plate #2	8	2	2
Weld metal	8	2	2
Heat-affected-zone metal	8	-	-
Correlation monitor	8	-	-
Dosimeters			
Pure Cu			
Pure Fe			
Pure Ni			
CoAl (0.15% Co)			
CoA1 (cadmium shielded)			
U238 (Type II capsules only)			
Np237 (Type II capsules only			
Thermal Monitors			
97.5% Pb, 2.5% Ag (579°F melting point)			
97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melting point)			

Table 4.1-11
CAPSULE SPECIMEN DATA, UNIT 2

	Number of Specimens		
	Charpy	Tensile	WOL
<u>Material - Capsules X, W, V, and S</u>			
Plate #1 (Longitudinal Orientation)	10	-	-
Plate #1 (Transverse Orientation)	10	2	4
Weld metal	8	2	-
Heat-affected-zone metal	8	-	-
Correlation monitor	8	-	-
<u>Material - Capsules T and U</u>			
Plate #1 (Longitudinal Orientation)	10	2	4
Plate #1 (Transverse Orientation)	10	-	-
Weld metal	8	2	-
Heat-affected-zone metal	8	-	-
Correlation monitor	8	-	-
<u>Material - Capsules Y and Z</u>			
Plate #1 (Longitudinal Orientation)	10	2	-
Plate #1 (Transverse Orientation)	10	-	-
Weld metal	8	2	4
Heat-affected-zone metal	8	-	-
Correlation monitor	8	-	-
<u>Dosimeters - Capsules S, T, U, V, W, X, Y, Z</u>			
Pure Cu			
Pure Fe			
Pure Ni			
CoAl (0.15% Co)			
CoA1 (cadmium shielded)			
U238			
NP237			
<u>Thermal Monitors - Capsules S, T, U, V, W, X, Y, Z</u>			
97.5% Pb, 2.5% Ag (579°F melting point)			
97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melting point)			

Table 4.1-12
SURVEILLANCE CAPSULE WITHDRAWAL SCHEDULE[a] FOR SURRY UNIT 1

Capsule Identification	Capsule Location	Estimated Withdrawal EFPY/Year	Insert EFPY/Year	Estimated Capsue Fluence (x 10^{19})[b]
T[c]	285°	1.1/1974	NA	0.271
W[c]	55°	3.4/1978	NA	0.368
V[c]	165°	8.0/1986	NA	1.80
X	65°	13.5/1994	NA	1.72
X	165°	NA	13.5/1994	NA
X[c]	165°	16.1/1997	NA	2.11
Z	245°	13.5/1994	NA	1.72
Z	285°	NA	13.5/1994	NA
Z[c]	285°	44.0/2027	NA	6.41
U	45°	13.5/1994	NA	0.893
U	65°	NA	13.5/1994	NA
U[e]	65°	NA	NA	4.59 (48.0 EFPY)
				6.82 (68.0 EFPY)
S[e]	295°	NA	NA	5.42(48.0 EFPY)
				7.65 (68.0 EFPY)
Y	305°	15.8/1997	NA	1.52
Y	165°	NA	15.8/1997	NA
Y[d]	165°	60/2044	NA	6.24 (48.0 EFPY) 8.14 (60.0 EFPY)

a. Withdrawal schedule meets requirements of ASTM E 185-82, *Standard Practice for Conducting Surveillance Tests for Light - Water Cooled Nuclear Power Reactor Vessels*, dated July 1, 1982.

b. 48.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 60-year license period. 68.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 80-year license period. Fluence values for withdrawn capsules are obtained from capsule test reports.

c. These capsules are required to satisfy the requirements of ASTM E 185-82 during the initial period of extended operation.

d. This capsule will be removed during the subsequent period of extended operation.

e. Standby Capsules S and U are available to satisfy potential fluence monitoring requirements during the subsequent license renewal period. Future projected capsule fluence values are related to asset management objectives.

Table 4.1-13
SURVEILLANCE CAPSULE WITHDRAWAL SCHEDULE[a] FOR SURRY UNIT 2

Capsule Identification	Capsule Location	Estimated Withdrawal EFPY/Year	Insert EFPY/Year	Estimated Capsule Fluence (x 10^{19})[b]
X[c]	285°	1.2/1975	NA	0.297
W[c]	245°	3.8/1979	NA	0.636
V[c]	165°	8.4/1986	NA	1.89
Y	295°	13.9/1995	NA	1.83
Y	165°	NA	13.9/1995	NA
Y[c]	165°	20.3/2002	NA	2.72
U	65°	27.1/2009	NA	3.16
U	285°	NA	27.1/2009	NA
U[c]	285°	49.0/2032	NA	7.31
T	55°	20.3/2002	NA	1.72
T	165°	NA	20.3/2002	NA
T[d]	165°	63.0/2047	NA	9.66
Z	305°	13.9/1994	NA	1.28
Z	245°	NA	13.9/1994	NA
Z[e]	245°	NA	NA	5.39 (48.0 EFPY) 8.21 (68.0 EFPY)
S	45°	15.0/1996	NA	1.07
W1	285°	NA	10.9/1991	NA
W1[f]	285°	16.2/1997	NA	0.78

a. Withdrawal schedule meets requirements of ASTM E 185-82, *Standard Practice for Conducting Surveillance Tests for Light - Water Cooled Nuclear Power Reactor Vessels*, dated July 1, 1982.

b. 48.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 60-year license period. 68.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 80-year license period. Fluence values for withdrawn capsules are obtained from capsule test reports with updates to the final values based upon WCAP-18242-NP.

c. These capsules are required to satisfy the requirements of ASTM E 185-82 during the initial period of extended operation.

d. This capsule will be removed during the subsequent license renewal period.

e. Standby Capsules Z is available to satisfy the potential fluence monitoring requirements during the 20-year license renewal and subsequent license renewal periods. Future projected capsule fluence values are related to asset management objectives.

f. Master Integrated Reactor Vessel Materials Surveillance Program capsule.

Table 4.1-14

UNIT 1 REACTOR PRESSURE VESSEL TOUGHNESS DATA (UNIRRADIATED)[d]

Material	Heat or Code No	Material Spec. No.	Cu (%)	Ni (%)	T_{NDT} (°F)	RT_{NDT} (°F)	NMWD[b] Upper Shelf Energy (ft-lb)
Closure head dome	7096	SA-533B Cl. 1 16MND5 (M2122)	.08	.66	-49	-49	-
Head flange	E4381-E4382	SA-508 Gr. 3 Cl. 1 16MND5 (M2113)	.06	.73	-67	-67	180[c]
Vessel flange	ZV-3339	A508 Cl. 2	.10	.65	-114.6[f]	-114.6[f]	>83
Inlet nozzle	9-5078	A508 Cl. 2	.159[g]	.87	3.4[f]	11.6[f]	64
Inlet nozzle	9-4819	A508 Cl. 2	.159[g]	.84	-47.2[f]	-47.2[f]	68
Inlet nozzle	9-4787	A508 Cl. 2	.159[g]	.85	3.1[f]	10.3[f]	63
Outlet nozzle	9-4762	A508 Cl. 2	.159[g]	.83	-92.0[f]	-87.5[f]	82
Outlet nozzle	9-4788	A508 Cl. 2	.159[g]	.84	-54.2[f]	-50.2[f]	71
Outlet nozzle	9-4825-1	A508 Cl. 2	.159[g]	.85	47.2[f]	-44.9[f]	68
Upper shell	122V109VA1	A508 Cl. 2	.11	.74	40	40	114[c]
Intermediate shell	C4326-1	A533B Cl. 1	.11	.55	10	10	115[c]
Intermediate shell	C4326-2	A533B Cl. 1	.11	.55	0	11.4[a]	94
Lower shell	C4415-1	A533B Cl. 1	.102	.493	20	20	103[c]
Lower shell	C4415-2	A533B Cl. 1	.11	.50	0	4.6[a]	82
Bottom head ring	123T338VA1	A508 Cl. 2	185[h]	.69	50	50[a]	96
Bottom dome	C4315-3	A533B Cl. 1	.14	.59	0	0	85

Table 4.1-14 (continued)

UNIT 1 REACTOR PRESSURE VESSEL TOUGHNESS DATA (UNIRRADIATED)[d]

Material	Heat or Code No	Material Spec. No.	Cu (%)	Ni (%)	T_{NDT} (°F)	RT_{NDT} (°F)	NMWD[b] Upper Shelf Energy (ft-lb)
Inter. Shell Vertical Weld Seam (L3, L4) & Lower Shell Vertical Weld Seam (L1)	8T1554 & Linde 80 flux Lot 8579		.16	.57	0[a]	-48.6	64/EMA[e]
Lower shell vertical weld seam, L2	299L44 & Linde 80 flux Lot 8596		.34	.68	0[a]	-74.3	64/EMA[e]
Inter. to lower shell girth seam	72445 & Linde 80 flux Lot 8597 and 8632		.22	.54	0[a]	-72.5	64/EMA[e]
Upper shell to Inter. shell girth seam & lower shell to bottom head ring girth seam (OD)	25017 & SAF 89 flux Lot 1197		.33	.10	0[a]	0[a]	64/EMA[e]
Inlet nozzle to upper shell weld seams[i]	299L44 & Linde 80 flux, Lot 8596 8T1762 & Linde 80 flux, Lot 8596		.34[i] .19[i]	0.68[i] 0.57[i]	-	-7.0[i] -4.9[i]	64[i] 64[i]
Outlet nozzle to upper shell weld seams[i]	8T1762 & Linde 80 flux, Lot 8578 8T1554B & Linde 80 flux, Lot 8579		.19[i] .16[i]	0.57[i] 0.57[i]	-	-4.9[i] -4.9[i]	64[i] 64[i]
Lower shell to bottom head ring girth weld (Root ID)	721858 & SAF 89 flux, Lot 1197		.08	1.0[j]	-	10[a]	78[k]

NOTES:

a. Estimated per NRC standard review plan, NUREG-0800, Section BTP 5-3.

b. Normal to major working direction - estimated per NRC standard review plan, NUREG-0800, Section BTP 5-3 for base metal material.

c. Actual values based on tests performed normal to the major working direction.

d. Reactor Vessel Fabricator Certified Test Reports

Table 4.1-14 (continued) (CONTINUED)
UNIT 1 REACTOR PRESSURE VESSEL TOUGHNESS DATA (UNIRRADIATED)[d]

Material	Heat or Code No	Material Spec. No.	Cu (%)	Ni (%)	T_{NDT} (°F)	RT_{NDT} (°F)	NMWD[b] Upper Shelf Energy (ft-lb)

e. The equivalent margins analysis in Reports BAW-2494, Revision 1; BAW-2178NP, Supplement 1; and BAW-2192NP, Supplement 1, demonstrate compliance with the requirements of 10 CFR 50, Appendix G.
f. Determined per BWRVIP-173-A, Appendix B Alternative Approach 2.
g. Generic value for nozzle forging based on mean plus two sigma approach and the data in Westinghouse nozzle database.
h. Generic value for A508, Class 2 shell forging based on mean plus two sigma approach and the data in ORNL/TM-2006/530 Table G.2.
i. Determined per BAW-2313, Revision 7, Supplement 1. The initial USE values for the Linde 80 welds are set to the generic value of 64 ft-lbs per BAW-2313, Revision 7, Supplement 1, Revision 1. Only limited Charpy test information is available for Heat #25017. Based on the average Charpy energy valve of the weld qualification tests completed at 10°F, the USE for Heat #25017 is at least 64 ft-lbs.
j. Generic value per 10 CFR 50.61.
k. Determined from surveillance capsule results from a sister plant.

Table 4.1-15

UNIT 2 REACTOR PRESSURE VESSEL TOUGHNESS DATA (UNIRRADIATED)

Material	Heat or Code No	Material Spec. No.	Cu (%)	Ni (%)	T_{NDT} (°F)	RT_{NDT} (°F)	NMWD[b] Upper Shelf Energy (ft-lb)
Closure head	02W1-1-1-1	SA508 Gr.3 Cl. 2	<.13	.37-1.03	-60	-60	191[c]
Vessel flange	ZV-3476	A508 Cl. 2	.10	.64	-156.3[e]	-156.3[e]	128
Inlet nozzle	9-4815	A508 Cl. 2	.159[f]	.87	-7.5[e]	4.5[e]	66
Inlet nozzle	9-5104	A508 Cl. 2	.159[f]	.84	-36.7[e]	-29.7[e]	73
Inlet nozzle	9-5205	A508 Cl. 2	.159[f]	.86	6.5[e]	6.5[e]	67
Outlet nozzle	9-4825-2	A508 Cl. 2	.159[f]	.85	-58.1[e]	-58.1[e]	73
Outlet nozzle	9-5086-1	A508 Cl. 2	.159[f]	.86	-26.6[e]	-26.6[e]	77
Outlet nozzle	9-5086-2	A508 Cl. 2	.159[f]	.87	-33.8[e]	-33.8[e]	71
Upper shell	123V303VA1	A508 Cl. 2	.11	.72	30	30[a]	104
Intermediate shell	C4331-2	A533B Cl. 1	.12	.60	-10	15.0[a]	84
Intermediate shell	C4339-2	A533B Cl. 1	.11	.54	-20	7.8[a]	83
Lower shell	C4208-2	A533B Cl. 1	.15	.55	-30	-30[a]	94
Lower shell	C4339-1	A533B Cl. 1	.107	.53	-10	-4.4[a]	101[c]
Bottom head ring	123T321VA1	A508 Cl. 2	.185[g]	.71	10	10[a]	101
Bottom dome	C4361-3	A533B Cl. 1	.15	.52	-20	-20	80

Table 4.1-15 (continued)
UNIT 2 REACTOR PRESSURE VESSEL TOUGHNESS DATA (UNIRRADIATED)

Material	Heat or Code No	Material Spec. No.	Cu (%)	Ni (%)	T_{NDT} (°F)	RT_{NDT} (°F)	NMWD[b] Upper Shelf Energy (ft-lb)
Inter. shell vertical weld seam L3 (100%), L4 (OD50%)	72445 & Linde 80 flux Lot8579		.22	.54	-	-72.5	64[h]/EMA[d]
Inter. & lower shell vertical welds							
Seam L1 (100%)	8T1762 & Linde 80 flux 8597		.19	.57	-	-48.6	64[h]/EMA[d]
Seam L2 (ID63%)	8T1762 & Linde 80 flux 8597		.19	.57	-	-48.6	64[h]/EMA[d]
Seam L2 (OD37%)	8T1762 & Linde 80 flux 8632		.19	.57	-	-48.6	64[h]/EMA[d]
Seam L4 (ID50%)	8T1762 & Linde 80 flux 8597		.19	.57	-	-48.6	64[h]/EMA[d]
Inter. to lower shell girth seam & lower shell to bottom head ring girth weld	0227 and Grau Lo Flux Lot LW320		.187	.545	0[a]		82/EMA[d]
Upper shell to Inter. shell girth seam	4275 & SAF 89 flux Lot 02275		.35	.10	0[a]		68[h]/EMA[d]
Inlet nozzle to upper shell weld seams[g]	8T1762 & Linde 80 flux Lots 8597 and 8632)		.19[h]	.57[h]	-	-4.9[h]	64[h]
Outlet nozzle to upper shell weld seams[h]	Rotterdam Weld		.35[i]	1.0[i]	-	30[i]	71[i]

Table 4.1-15 (continued)
UNIT 2 REACTOR PRESSURE VESSEL TOUGHNESS DATA (UNIRRADIATED)

Material	Heat or Code No	Material Spec. No.	Cu (%)	Ni (%)	T_{NDT} (°F)	RT_{NDT} (°F)	NMWD[b] Upper Shelf Energy (ft-lb)

NOTES:

a. Estimated per NRC standard review plan, NUREG-0800, Section BTP 5-3.
b. Normal to major working direction - estimated per NRC standard review plan, NUREG-0800, Section BTP 5-3 for base metal material.
c. Actual values based on test performed normal to the major working direction
d. The equivalent margins analysis in Reports BAW-2494, Revision 1; BAW-2178NP, Supplement 1; and BAW-2192NP, Supplement 1, demonstrate compliance with the requirements of 10 CFR 50, Appendix G.
e. Determined per BWRVIP-173-A, Appendix B Alternative Approach 2.
f. Generic value for nozzle forging mean plus two sigma approach and the data in Westinghouse nozzle database.
g. Generic value for A508, Class 2 shell forging based on mean plus two sigma approach and the data in ORNL/TM-2006/530 Table G.2.
h. Determined per BAW-2313, Revision 7, Supplement 1. The initial USE values for the Linde 80 welds are set to the generic value of 64 ft-lbs per BAW-2313, Revision 7, Supplement 1, Revision 1. Only limited Charpy test information is available for Heat #4275. Based on the average Charpy energy value of the weld qualification tests completed at 10°F, the USE for Heat#4275 is at least 68 ft-lbs.
i. No data available. The chemistry values of this weld were taken to be generic values per Regulatory guide 1.99, Revision 2. The initial RT_{NDT} value was determined using ASME III minimum requirements at the time of fabrication and NUREG-0800, Section BTP 5-3, Position 1.1(4). The value was determined using ASME III minimum requirements at the time of fabrication and NUREG-0800, Section BTP 5-3, Position 1.2

Figure 4.1-1
TYPICAL SURVEILLANCE CAPSULE, ELEVATION VIEW

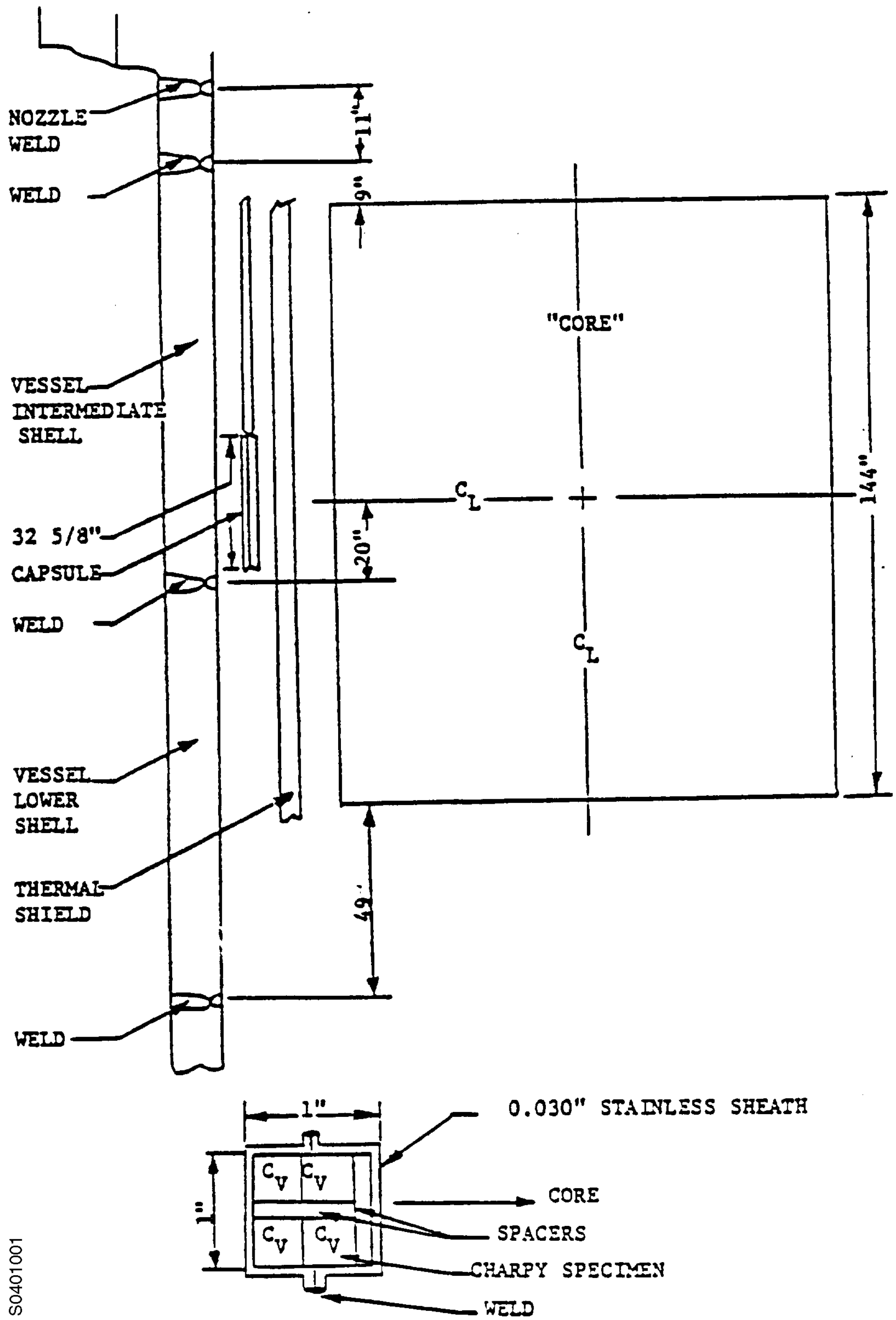
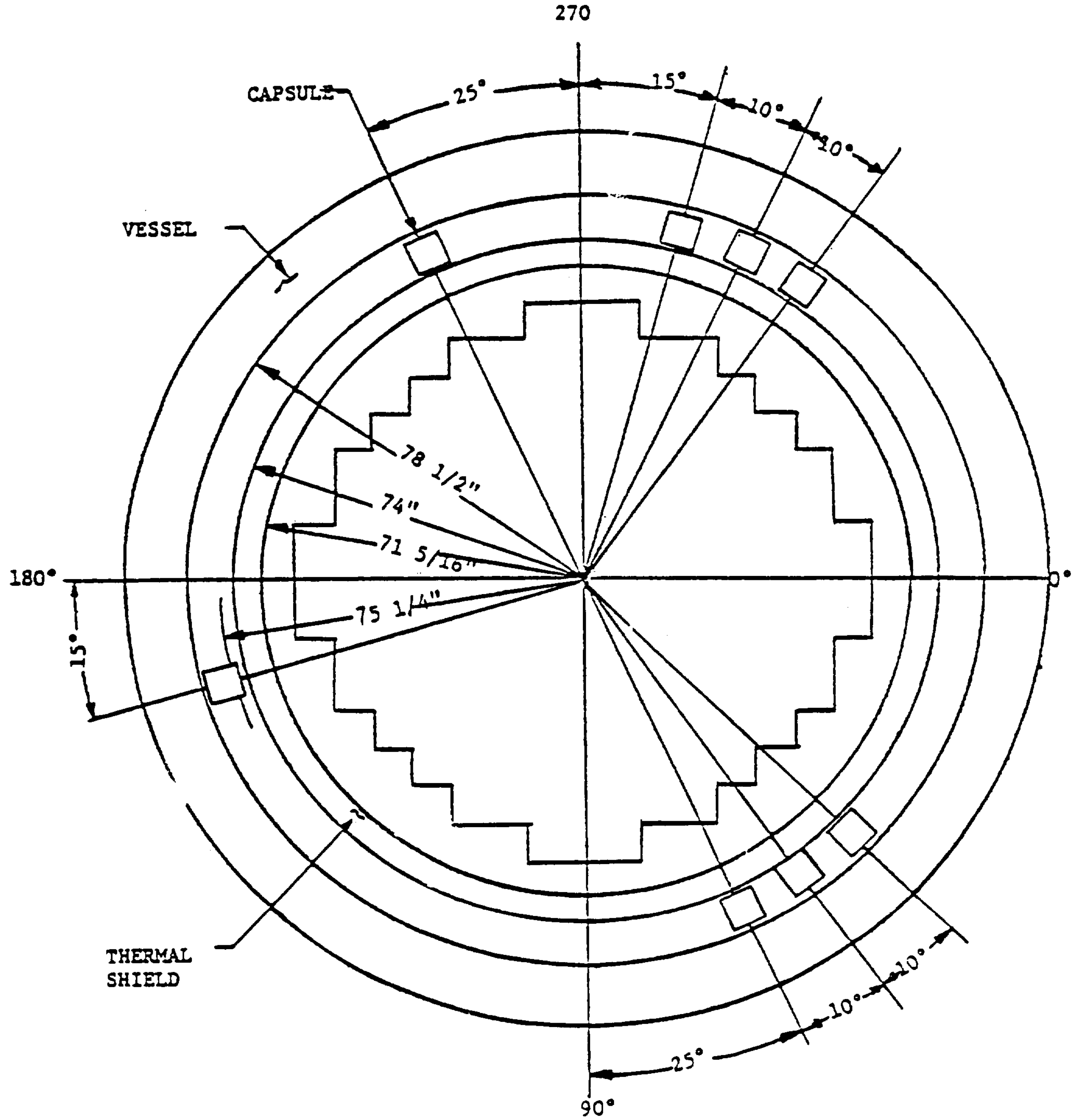


Figure 4.1-2
INSTALLED SURVEILLANCE CAPSULE, PLAN VIEW



S0401002

VESSEL VERTICAL WELD SEAM LOCATIONS	
INTERMEDIATE SHELL	45° + 225°
LOWER SHELL	135° + 315°

Intentionally Blank

4.2 SYSTEM DESIGN AND OPERATION

4.2.1 General Description

The reactor coolant system consists of three similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a steam generator, a pump, two loop-stop valves, loop piping, and instrumentation. The pressurizer surge line is connected to one of the loops on the reactor side of a stop valve. Auxiliary system piping connections into the reactor coolant piping are provided as necessary. A flow diagram of the system is shown in Figure 4.2-1 and Reference Drawings 1 and 2. All of the major components of the reactor coolant system are located inside containment.

Reactor coolant system and component design data are listed in Tables 4.1-1 through 4.1-7.

Pressure in the system is controlled by the pressurizer, where water and steam pressure are maintained through the use of sprays and electrical heaters. Steam can be formed by the heaters or condensed by pressurizer spray to minimize pressure variations due to contraction and expansion of the coolant. Instrumentation to be used in the pressure control system is described in Chapter 7. Spring-loaded code safety valves and power-operated relief valves are connected to the pressurizer and discharge to the pressurizer relief tank, where the discharged steam is condensed and cooled by mixing with water. To ensure degassification and decay heat removal under certain accident conditions without relying on main coolant pump operation the reactor coolant vent system provides remote venting capability of the reactor vessel head and pressurizer steam space.

4.2.2 Components

4.2.2.1 Reactor Vessel

The reactor vessel is a cylinder with a hemispherical bottom and a flanged and gasketed removable upper head. Figure 4.2-2 is a schematic of the reactor vessel. The materials of construction of the reactor vessel are given in Table 4.2-1. Provision is made for removal of reactor internals if required during reactor life.

Coolant enters the reactor vessel through inlet nozzles in a plane just below the vessel flange and above the core. The coolant flows downward through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel, where it reverses direction. Approximately 95% of the total coolant flow is effective for heat removal from the core. The remainder of the flow includes the flow through the control rod assembly guide thimbles, the leakage across the fuel assembly outlet nozzles, and the flow deflected into the head of the vessel for cooling the upper flange. All the coolant is united and mixed in the upper plenum, and the mixed coolant stream then flows out of the vessel through exit nozzles located on the same plane as the inlet nozzles.

The reactor vessel contains the core support assembly, upper plenum assembly, fuel assemblies, control rod assemblies, surveillance specimens, and incore instrumentation. The reactor vessel internals are designed to direct the coolant flow, support the reactor core, and guide the control rod assemblies in the withdrawn position.

The reactor internals are described in detail in Section 3.5, and the general arrangement of the reactor vessel and internals is shown in Figure 3.5-2. Design data are listed in Table 4.1-2.

A one-piece thermal shield, concentric with the reactor core, is located between the core barrel and the reactor vessel. The thermal shield is bolted and welded to the top of the lower core barrel. The thermal shield, which is cooled by the coolant on its downward pass, protects the vessel by attenuating much of the gamma radiation and some of the fast neutrons that escape from the core. This reduces thermal stresses in the vessel that result from heat generated by the absorption of gamma energy. The thermal shield is illustrated in Figure 3.5-6 and described in Section 3.5.1.1.

Fifty incore instrumentation nozzles are located on the lower head. The reactor vessel closure head and the reactor vessel flange are joined by 58 6-inch-diameter studs. Two concentric metallic o-rings seal the reactor vessel when the reactor closure head is bolted in place. A leakoff connection is provided between the two o-rings to monitor leakage across the inner o-ring. In addition, a leakoff connection is also provided beyond the outer o-ring seal.

The reactor vessel insulation is of the reflective type, supported from the nozzles, and consisting of inner and outer sheets of stainless steel spaced 3 inches apart with multilayer aluminum foil as the insulating agent. The clearance between the reactor vessel and insulation is 0.5 inch. Insulation sheets are also provided for the reactor closure head and are supported on the refueling seal ledge and vent shroud support rings.

For Unit 1, to reduce radiation exposure to personnel during reactor vessel head removal and during maintenance operations in the vicinity of the head a permanent reactor vessel head shield has been installed. This shielding consists primarily of cylindrical steel plate (ASTM A36) that is permanently attached to the intermediate lift ring. The shielding is comprised of three sections, each spanning 120 inches. Each section is approximately one inch thick, six feet tall and weighs 3500 pounds. To allow ease of maintenance activities a cutout is provided in the shield for access to the Reactor Vessel Level Indication System. Cutouts are also provided for cooling shroud ventilation nozzles, which are covered by swing doors.

For Unit 2, to reduce exposure to personnel during reactor vessel head removal and during maintenance operations in the vicinity of the head a permanent reactor vessel head shield has been incorporated as an integral part of the CRDM cooling shroud. The shield consists of upper and lower sections. The lower section consists primarily of cylindrical stainless steel plate that is permanently attached to the reactor vessel head lifting rig lugs by special mounting devices. The lower shield/cooling shroud is comprised of four curved segments bolted together to encircle the RV head. These segments are constructed of 3/8 inch ASTM A240, TP304 stainless steel plate that is 40 inches high welded to the inside of one inch ASTM A240, TP304 stainless steel that is 43 inches high and weighs approximately 4500 lb. Three of the segments each have an opening through which air is drawn from the containment as part of the CRDM cooling system. There are holes in two of the segments, such that the RV head vent line passes through one without contacting the shield/shroud and the RVLIS line passes through the other one without contacting the shield/shroud. To accomplish the radiation shielding function, a sliding door is provided to cover each opening when work is being performed in the head area. The doors slide on wheels on a rail mounted above each opening. Door restraints are mounted on the lower shield/shroud to keep the door from moving radially away from the lower shield/shroud. The upper shield/cooling shroud is square in design. The upper shield/cooling shroud consists of four flat side panels and four corner panels. The side and corner panels are constructed of one inch ASTM A240, TP304 stainless steel that is approximately 50 inches high and weighs approximately 7000 lb.

The head lifting rig is classified as QA Category II and since the addition of the shielding to the reactor vessel head does not modify or change the operation, function, or design of the Reactor Coolant System (RCS) or any of its components, this design change is classified as QA Category II. The head shielding is seismically designed in order to protect safety-related equipment in the area following a postulated seismic event.

Protective coating of the Unit 1 shielding was performed in accordance with ANSI N101.4, *Quality Assurance for Protective Coatings Applied to Nuclear Facilities*, prior to receipt on site. All material installed by this design is environmentally qualified for pressure, temperature, relative humidity, and radiation conditions inside the containment during normal operation and following accident conditions. There are no protective coatings on the Unit 2 shielding.

Manufacture of the original Surry vessels was begun by the Babcock & Wilcox Company at Mt. Vernon, Indiana. However, due to scheduling problems, it was necessary to transfer these vessels in a partially fabricated state to the Rotterdam Dockyard Company, Rotterdam, The Netherlands, for completion of fabrication.

The basic construction of the Surry vessels consists of the following:

1. Vessel assembly

   a. Vessel flange - Machined forging.

   b. Nozzle shell - Machined forging, penetrated by six primary coolant nozzles.

   c. Intermediate and lower shells - Each fabricated from two formed cylindrical plates. Two longitudinal weld seams.

   d. Lower head transition ring - Machined forging.

   e. Lower head - Formed from single plate, penetrated by 50 instrumentation tubes.

2. Closure head assembly

   Unit 1 Dome section - Hemispherical dished segment plate (one piece), penetrated by 65 control rod drive mechanism housings.

Unit 2 closure head assembly is a single forging (one piece), penetrated by 71 total penetrations as follows:

a. 48 penetrations for Control Rod Drive Mechanism (CRDM) head adapters with threaded housings,

b. 17 penetrations for spare CRDM head adapters with threaded capped housings,

c. 4 penetrations with cap,

d. 1 penetration for reactor vessel head venting,

e. 1 penetration for Reactor Vessel Level Indication System (RVLIS).

The replacement RVCH was originally intended for NAPS Unit 2. Some fabrication was performed before it was redesigned for Surry Unit 2. Therefore there are 4 penetrations with cap on the Surry Unit 2 head.

Inside surfaces of both closure head and vessel assembly that contact primary coolant are clad with corrosion-resistant material.

At the time of their transfer from Babcock & Wilcox to Rotterdam, the original vessels were at the following stages of completion:

1. Surry Unit 1

   a. Closure head

      Original closure head has been replaced with a closure head fabricated by Framatome ANP for a French utility power plant and purchased by Dominion for Surry Unit 1.

   b. Vessel

      Flange welded to nozzle shell, six nozzles welded in nozzle shell, inside surfaces clad.

      Intermediate shell welded to lower shell, not clad.

      Lower head dome welded to transition ring, inside surfaces clad.

2. Surry Unit 2

   a. Closure head

      The replacement Unit 2 closure head was fabricated by Mitsubishi Heavy Industries, LTD at the Kobi Shipyard and Machinery Work, Japan.

   b. Vessel

      Flange welded to nozzle shell, three of six primary nozzles welded.

      Intermediate and lower shells formed and welded but not welded together, no clad.

Lower head dome welded to transition ring, not clad.

Four solenoid operated globe valves initiate and terminate venting in two redundant flow paths at each vent location. These isolation valves are powered by vital dc power supplies and are fail-closed active valves. A 3/8-inch orifice is installed in each flow path to minimize the reactor coolant pressure boundary extension and to maintain the venting rate at an acceptable value. System operation is conducted from the control room of each unit.

4.2.2.2 **Pressurizer**

The general arrangement of the pressurizer is shown in Figure 4.2-4, and the design data are listed in Table 4.1-3.

The pressurizer maintains the required reactor coolant pressure during steady-state operation, limits the pressure changes caused by coolant thermal expansion and contraction during normal load transients, and prevents the pressure in the reactor coolant system from exceeding the design pressure.

The pressurizer contains replaceable direct immersion heaters, safety and relief valves, a spray nozzle, a vent system, and interconnecting piping, valves, and instrumentation. The electric heaters are located in the lower section of the vessel, and maintain the pressure of the reactor coolant system by keeping the water and steam in the pressurizer at system saturation temperature. Table 4.1-3 indicates initial design capacity for pressurizer heaters. The initial heater design capacity allows for operation with some heaters out of service. With all heaters in service, the heaters are capable of raising the temperature of the pressurizer and contents at approximately 55°F/hr during reactor start-up. Acceptable operation has been evaluated with 1200 kW of heater capacity, which would be capable of raising the temperature of the pressurizer and contents at approximately 52°F/hr during reactor start-up.

The pressurizer is designed to accommodate positive and negative surges caused by load transients. The surge line attached to the bottom of the pressurizer connects the pressurizer to the hot leg of a reactor coolant loop. During a positive surge, caused by a decrease in load, the spray system, which is fed from the cold leg of a coolant loop, condenses steam in the vessel to prevent the pressurizer pressure from reaching the operating point of the power-operated relief valves. Power-operated spray valves on the pressurizer limit the pressure during load transients. In addition, the spray valves can be operated remote manually from the control room. A small continuous spray flow is provided to ensure that the pressurizer liquid is homogeneous with the coolant and to prevent excess cooling of the spray and surge line piping.

During a negative pressure surge, caused by an increase in load, flashing of water to steam and generation of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. Heaters are also energized on high water level during positive surges to heat the subcooled surge water entering the pressurizer from the reactor coolant loop.

A Westinghouse Owners Group analysis has determined that the minimum requirement to maintain natural circulation in a three-loop plant with a pressurizer volume of 1300 ft^3 is 125 kW of heater capacity. Two backup heater groups rated at 250 and 200 kW and their associated controls are energized from redundant emergency buses H and J, which are capable of being fed from either offsite power or emergency power. The Class 1E interfaces for motive and control power are protected by safety grade circuit breakers.

The pressurizer heaters are not automatically shed from the emergency power sources upon the occurrence of a safety injection actuation signal. The pressurizer heaters will, however, be automatically shed from the Emergency Bus with a Loss of Offsite Power (LOOP). Once the Emergency Bus has been reenergized, the pressurizer heaters are sequenced onto the bus after a 180-second time delay. Refer to Section 8.5 for a more detailed description of the Emergency Power System. Procedures have been implemented to instruct the operator in the use of pressurizer heaters in establishing and maintaining natural circulation. This is the preferred method of controlling the RCS pressure during a cooldown.

The pressurizer is constructed of carbon steel, with internal surfaces clad with austenitic stainless steel. The heaters are sheathed in austenitic stainless steel.

The pressurizer vessel surge nozzle is protected from thermal shock by a thermal sleeve. A thermal sleeve also protects the pressurizer spray nozzle connection. A manway is provided in the top portion of the pressurizer.

The pressurizer vent system is provided to remove non-condensable gasses from the pressurizer steam space. The pressurizer vent is designed and operated like the reactor head vent system discussed in Section 4.2.2.1. The pressurizer vent system does not provide a means of pressure control.

4.2.2.3 **Steam Generators**

A steam generator repair program was completed at the Surry Power Station in 1980 and 1981 for Units 2 and 1, respectively. The purpose of the program was to repair degradation caused by corrosion-related phenomena and to restore the integrity of the steam generators to a level equivalent to new equipment. The repair program basically consisted of replacing the steam generator lower assembly and refurbishing the upper assembly. This program is described in Reference 1. The following description pertains to the as-modified system. Principal design data are given in Table 4.1-4; a general sectional view is given in Figure 10.3-2.

4.2.2.3.1 General System Description

Each loop of the reactor coolant system contains a vertically mounted U-tube steam generator. These generators consist of two integral sections: an evaporator section and a steam drum section. The evaporator section consists of a U-tube heat exchanger, while the steam drum section houses moisture-separating equipment. The steam drum section is located in the upper part of the steam generator. The lower assembly of each steam generator is designed and manufactured in accordance with Sections III and XI of the 1974 edition of the ASME Boiler and Pressure Vessel Code, including addenda through Winter 1976. The steam generator lower assemblies bear the applicable ASME Code stamp. The original upper shell was reanalyzed based on the above referenced version of the Code (excluding the Appendix G fracture mechanics analysis).

High pressure and high temperature reactor coolant flows into the channel head, through the Inconel U-tubes, and back to the channel head. A partition plate divides the channel head into inlet and outlet sections. An access opening for inspection and maintenance is provided in each section of the channel head. Welding of the U-tubes to the tube support plate ensures zero leakage across the tube joints. The tubes are supported at intervals by horizontal support plates.

4.2.2.3.2 Steam Generator Design Features

The current steam generators include many design improvements over the original steam generators. These features improve the flow distribution, improve bundle access, reduce secondary-side corrosion, facilitate maintenance and inservice inspection activities, and ultimately ensure the integrity of the steam generators. The replacement lower assembly includes the following features:

1. A cast channel head is used to meet current inservice inspection (ISI) requirements. Improvements incorporated affect the tube-to-tubesheet weld and the ends of the primary nozzles.
2. Primary nozzle closure rings are welded inside the channel head at the base of each primary nozzle so that closure plates can be installed during primary chamber maintenance. This design allows the plates to be bolted to the rings for quick installation and removal. Closure plates allow maintenance or inspection to be conducted in the channel head while other operations are conducted with the reactor cavity flooded.
3. The steam generators were originally equipped with a channel head drain that allowed the steam generator to be completely drained before performing inspection and maintenance activities. The channel head drains have since been removed and capped due to transgrannular stress corrosion cracking.
4. Recessed tube-to-tubesheet welds were used in conjunction with full-depth tube roll for all tubes (see Figure 4.2-5). Absence of the protruding tube stub in the present design results in lower entry losses and therefore a lower pressure drop in the primary loop. In addition, a possible point of crud buildup is avoided with this design.
5. The primary manways and all handholes are designed to receive either welded diaphragms, gaskets, or both, without any modifications. In addition, bolt-on trunnions are provided for two handholes to facilitate installation.

6. All pressure-containing parts, with the exception of the Inconel tubes, are made of carbon or low-alloy steel. All surfaces in contact with the reactor coolant are made of, or clad with, stainless steel or Inconel.

7. The locations of each tube are marked in accordance with an established grid system, i.e., row and column number. The marking of the tubes facilitates identification of tubes for plugging or inspection, thereby minimizing radiation exposure and time required for the activity.

8. The insulation for the steam generators and associated piping is reflective type, stainless steel jacket, fabricated in removable sections where access to welds is required for inservice inspection.

   Reflective insulation was chosen for the following reasons:

   a. Chloride and fluoride free.

   b. Quickly removed and replaced for inservice inspection.

   c. All metal, will not absorb water.

   d. Easy to decontaminate.

   Areas covered with this insulation are as follows:

   a. Steam generators - the entire steam generator.

   b. Reactor coolant piping - reactor coolant piping in each loop from just beyond the hot-leg loop stop valve to the steam generator, and from the bottom of the loop at the pipe restraint on the cold leg to the steam generator.

   c. Main steam piping - from just beyond the crane wall penetration back to the steam generator.

   d. Feedwater piping - from just beyond the crane wall penetration back to the steam generator.

   The insulation was cleaned, tested, and/or inspected, and protected against contamination prior to shipping to the site. During installation, handling was performed in a manner that prevented contamination by chlorides, halogens, and other contaminants as described in the specification for steam generator insulation. All surfaces over which the insulation was placed were cleaned and decontaminated of corrosion-forming residues. Cleaning of stainless steel piping met the criteria described in Regulatory Guides 1.37 and 1.44.

9. Each steam generator was constructed with 3342 Inconel-600 thermally treated tubes. The tube dimensions are 7/8-inch o.d. with 0.05-inch wall thickness.

Extensive research has determined that significant improvement in the stress corrosion resistance of Inconel-600 tubing can be achieved by modification of the metallurgical structure through thermal treatment. The primary objective of this treatment is to develop an improved metallurgical structure, associated with the grain boundary precipitate morphology, which provides increased margin with respect to stress corrosion performance. Several benefits result from this treatment: improved resistance to stress corrosion cracking in NaOH, resistance to intergranular attack in oxygenated environments and in sulfur-containing species, and reduction of residual stress imparted by tube processing.

Certain heat treatments can improve caustic stress corrosion resistance but result in a chromium-depleted grain boundary layer (sensitization) that is not as resistant to off-chemistry environments, should they be experienced. Analysis of available data indicates that there is a broad band of temperature and time within the typical sensitization range for Inconel-600 which provides improved resistance to stress corrosion cracking in both caustic and pure water environments. The thermal treatment used was within this time-temperature band.

The thermal treatment was designed to improve the corrosion resistance against secondary-side attack, specifically caustic stress corrosion. The treatment also results in resistance to primary-side stress corrosion cracking. The thermal treatment was performed as a final operation on the straight-length tubing, after the straightening and polishing. It consisted of heat-treating the tubing in a vacuum at a nominal temperature of 1300°F for about 15 hours. This treatment results in a microstructure consisting of semi-continuous grain boundary precipitates, but with little or no chromium depletion adjacent to the boundaries. In addition, the eight inner rows (smallest diameter) of tubes were stress-relieved following bending at a temperature of about 1300°F for several hours. This microstructure change in conjunction with the relief of most residual stresses provides the corrosion resistance to both primary-side and secondary-side environments.

Intergranular attack in environments containing oxygen and/or sulfur has been evaluated. The special thermal heat treatment was established to ensure that the grain boundary morphology is not conducive to intergranular attack. It is known that grain boundary carbide precipitation, while beneficial in caustic and other species, may be detrimental in certain oxygenated and sulfur-bearing environments if the material is “sensitized,” i.e., there is a chromium-depleted region adjacent to the boundaries. The time and temperature of the special heat treatment have been established to ensure that the microstructure is “desensitized” toward intergranular attack in environments containing oxygen and sulfur.

Test results obtained during the development of the special heat-treating process validated the above. Desensitization of the material was routinely monitored during production.

4.2.2.4 **Reactor Coolant Pumps**

Each reactor coolant loop contains a vertical single stage centrifugal pump using a controlled leakage seal assembly. A view of a controlled leakage pump is shown in Figure 4.2-6.

The principal design parameters for the pumps are listed in Table 4.1-5. The reactor coolant pump estimated performance and NPSH characteristics are shown in Figure 4.2-7. The performance characteristic is common to all of the higher specific speed centrifugal pumps, and the “knee” at about 45% design flow introduces no operational restrictions since the pumps operate at full speed.

Reactor coolant is pumped by the impeller attached to the bottom of the rotor shaft. The coolant is drawn up through the impeller, discharged through the passages in the diffuser, and out through a discharge nozzle in the side of the casing. The motor-impeller is removed from the casing for maintenance or inspection without removing the casing from the piping. All parts of the pumps in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion-resistant materials.

The pump uses a three-stage seal arrangement. The seals control leakage, used as seal lubrication and cooling, along the pump shaft. The number 1 and 2 seals divert the majority of seal leakage to the VCT. The number 3 seal minimizes the leakage of water and vapor from the pump into the containment atmosphere. Leakage past the number 3 seal is directed to the suction of the PDTT pump.

High-pressure water flow from the charging pumps is injected into the reactor coolant pump, where a portion of the flow goes down the pump shaft past the thermal barrier to the reactor coolant system, and a portion travels up the shaft past the lower radial bearing to the number 1 seal cavity. The thermal barrier functions to cool hot reactor coolant flowing to the seal package, in the event seal injection flow is lost.

Component cooling water is supplied to the motor bearing lube oil coolers, air coolers, and the thermal barrier cooling coil. On loss-of-offsite power, the reactor coolant pumps and the component cooling pumps are de-energized due to the loss of station service and emergency stub buses. Component cooling water flow to the thermal barrier can be manually reinitiated following the restoration of the emergency stub bus after the automatic start of the diesel generators.

The squirrel cage induction motor driving the pump is air-cooled, and has oil-lubricated thrust and radial bearings. A water-lubricated bearing provides radial support for the pump shaft.

A flywheel on the shaft above the motor provides additional inertia to extend flow coastdown. Each pump contains a ratchet mechanism to prevent reverse rotation.

The original RCP motors can be replaced with motors from the North Anna plant, with appropriate compensatory measures taken. An oil collection system attaches to the original RCP motors to reduce the potential for fire in the Containment Building (see Section 9.10.4.12 for further information).

All the pressure-bearing parts of the reactor coolant pump are analyzed in accordance with Article 4 of the ASME Code, Section III. This includes the casing, the main flange, and the main flange fasteners. The analysis includes pressure, thermal, and cyclic stresses; and these are compared with the code allowable stresses.

Mathematical methodologies are prepared and used in the analysis, which proceeds in two phases:

1. In the first phase, the design is checked against the design criteria of the ASME Code, with pressure stress calculations, although thermal effects are included implicitly with the experience factors. By this procedure, the shells are profiled to attain optimum metal distribution, with stress levels adequate to meet the more limiting requirements of the second phase.
2. In the second phase, the interactivity forces needed to maintain geometric capability between the various components are determined at design pressure and temperature, and applied to the components along with the external loads, to determine the final stress state of the components. These are finally compared with the code allowable values.

There are no other sections of the code that are specified as areas of compliance, but where code methods, allowable stresses, fabrication methods, etc., are applicable to a particular component, these are used to give a rigorous analysis and conservative design.

4.2.2.5 **Pressurizer Relief Tank**

Principal design parameters of the pressurizer relief tank are given in Table 4.1-3.

Steam discharged from the power-operated relief valves or from the safety valves passes to the pressurizer relief tank, which is partially filled with water at or near containment ambient temperature, under a predominantly nitrogen atmosphere. Steam is discharged under the water level to condense and cool by mixing with the water. The tank is equipped with a spray, and a drain to the vent and drain system (Section 9.7), which is operated to cool the tank following a discharge.

The tank size is based on the requirement to condense and cool a discharge equivalent to 110% of volume between zero-power pressurizer water level setpoint and the high water level reactor trip setpoint.

Rupture disks protect the tank from overpressurization caused by a discharge exceeding the design value. The rupture disks, which discharge into the reactor containment, have a relief capacity in excess of the combined capacity of the pressurizer safety valves. The tank design pressure (and the rupture disk setting) is twice the calculated pressure resulting from the maximum safety valve discharge described above. This margin is to prevent deformation of the disks. The tank and rupture disk holders are also designed for full vacuum to prevent tank collapse if the tank contents cool without nitrogen being added.

The discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent backpressure at the valves from exceeding 20% of the setpoint pressure at full flow.

The pressurizer relief tank, by means of its connection to the vent and drain system (Section 9.7), provides a way for removing any non-condensable gases from the reactor coolant system that might collect in the pressurizer vessel.

The tank is constructed of carbon steel with a corrosion-resistant coating on the internal surface.

4.2.2.6 **Piping**

The general arrangement of the reactor coolant system piping is shown on the station layout drawings in Section 15.1. Piping design data are presented in Table 4.1-6.

The reactor coolant piping layout is designed on the basis of providing floating supports for the steam generators and reactor coolant pumps to absorb the thermal expansion from the fixed or anchored reactor vessel.

The austenitic stainless steel reactor coolant piping and fittings that make up the loops are 29-inch i.d. in the hot legs, 27.5-inch i.d. in the cold legs, and 31-inch i.d. between each loop's steam generator outlet and its reactor coolant pump suction.

Smaller piping, including the pressurizer surge relief and spray lines, as well as drains and connections to other systems, are austenitic stainless steel. Joints and connections are welded except for stainless steel flanges such as the connections to the carbon steel pressurizer relief tank and the connections at the relief and safety valves, the MOV relief header drains, the loop flow elements, the reactor head vent piping spectacle flanges, and the reactor head vent valve pipe flanges.

Three resistance temperature detectors are installed in the hot leg of each loop near the inlet to the steam generator. One resistance temperature detector is installed in the cold leg of each loop at the discharge of the reactor coolant pump. These detectors are mounted in thermowells and provide reactor protection and control. A resistance temperature detector is also provided on each hot and cold leg to provide information when the loop is shut down.

As a result of IE Bulletin 79-27, the power supplies to each reactor coolant system loop wide-range T_H-T_C combination have been diversified. The associated hot-leg and cold-leg temperature loops in each reactor coolant system loop are supplied by the same vital power source, which is different from the other two T_H-T_C combinations. Also, the associated T_H and T_C instruments of each reactor coolant system loop input to their own recorder on the main control board. This modification of the wide-range temperature loops ensures that indication of differential temperature between T_H and T_C in at least two reactor coolant loops will be available in the event of the loss of reactor coolant pumps and any vital bus.

Thermal sleeves are installed at the following locations where high thermal stresses could otherwise develop due to rapid changes in fluid temperature during normal operational transients:

1. Return line from the residual heat removal loop.

2. Both ends of the pressurizer surge line.
3. Pressurizer spray line connection to the pressurizer.
4. Charging line connection.
5. Loop fill header connections to each loop.

4.2.2.7 Small Valves

All valve surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion-resistant materials. Connections to stainless steel piping are welded.

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection.

4.2.2.8 Loop Stop Valves

The reactor coolant loop stop valves, one of which is shown on Figure 4.2-8, are remotely controlled, motor-operated gate valves that permit any loop to be isolated from the reactor vessel during cold or refueling shutdowns. A stop valve is installed on each hot leg and in each cold leg. During return to service of an isolated filled loop, coolant is circulated through a bypass line, which contains a remotely controlled, motor-operated stop valve. This bypass valve is closed during normal loop operation. A valve pump interlock circuit prevents the starting of the reactor coolant pump in a given loop unless either (a) both hot leg and cold leg loop stop valves are open or (b) the cold leg loop stop valve is closed and the bypass valve is open. The interlock also prevents pump operation if the bypass valve and either of the stop valves are closed.

To ensure against an accidental start-up of an unborated and/or cold isolated loop, an additional valve interlock system is provided that meets the IEEE-279 *Criteria for Nuclear Power Plant Protection Systems,* August 1968. This is shown on Reference Drawing 1, which indicates a relief line and bypass around the cold-leg stop valve. These additional valve temperature and flow interlocks require that a controlled flow of reactor coolant is circulated through the relief line of the inactive loop insuring that boron concentration and temperature of the isolated loop are brought to equilibrium with the remainder of the reactor coolant system, prior to opening the cold leg loop stop valve. This controlled flow will minimize the possibility of a sudden reactivity addition from cold water or boron dilution.

The valve-temperature and valve-flow relief line interlocks are provided to:

1. Prevent opening of a hot-leg loop stop valve unless the cold-leg loop stop valve is closed.
2. Prevent opening of a cold-leg loop stop valve unless:
    a. The hot-leg loop stop valve has been opened a specified time.
    b. The loop bypass valve has been opened a specified time.
    c. Flow has existed through the relief line for a specified time.

d. The cold-leg temperature is within 20°F of the highest cold-leg temperature in other loops and the hot-leg temperature is within 20°F of the highest hot-leg temperature in the other loops.

Returning an isolated loop to service requires that the above interlocks be satisfied, a minimum temperature exists in the loop, and that core reactivity be monitored using a source range nuclear instrument channel.

If a loop was initially drained, the above interlocks can be bypassed. The initially isolated and drained loop may be returned to service by partially opening a loop stop valve and filling the loop in a controlled manner from the reactor coolant system. If using the Volume Control Tank (VCT) as the makeup source, the charging flow from the VCT is periodically sampled during the backfill evolution to ensure its boron concentration meets the minimum refueling water boron concentration requirement established by Technical Specification 3.10.A.9. Makeup to the Reactor Coolant System solely through auxiliary spray during the backfill evolution is prohibited to ensure that a sufficient fraction of makeup flow is mixed with coolant in the active Reactor Coolant System volume and flows through the core, where the source range instrumentation is available to provide secondary indication of improperly blended makeup flow. The vacuum-assisted backfill evolution involves initiation of reactor coolant pump seal injection in the isolated and drained loop to allow establishment of a partial vacuum prior to partially opening the cold leg loop stop valve. The following controls are required to assure that no sudden positive reactivity addition or loss of reactor coolant system inventory occurs during the backfill evolution:

1. Only one loop should be filled at a time.
2. The isolated loop must be verified to be drained.
3. Adequate reactor coolant inventory exists to assure that, during the fill operation, decay heat removal is maintained. This minimum inventory level should not be violated during the fill operation.

If this method is used to fill a loop, then the loop is no longer considered to be isolated and the requirements for returning the isolated loop to service are not applicable as long as the loop stop valves are opened within a specified time.

The parameters of each reactor coolant loop stop valve are shown in Table 4.1-7.

4.2.3 Pressure-Relieving Devices

The reactor coolant system is protected automatically against overpressure by control and protective circuits such as the high-pressure trip, and by code safety valves connected to the top head of the pressurizer. The code safety and power-operated relief valves discharge into the pressurizer relief tank, which condenses and collects the valve effluent. The schematic arrangement of the relief devices is shown in Reference Drawing 2, and the valve design parameters are given in Table 4.1-3. Valve sizes are determined as indicated in Section 4.3.4.

Power-operated relief valves and code safety valves are provided to protect against pressure surges which are beyond the pressure limiting capacity of the pressurizer spray. The self-actuated code safety valves provide ultimate overpressure protection; these valves are completely independent of all control and protective circuits.

The 6-in. pipes connecting the pressurizer nozzles to their respective code safety valves are shaped in the form of a loop seal. As a result of normal heat loss to the ambient, steam continually condenses in the loops. The 1-inch drain lines on the bottom of each PSV loop seal join to form a common line which connects to the pressurizer at a point approximately 30 feet below the loops. This allows the condensate to continuously drain back to the pressurizer and prevents the accumulation of water in the loop seals.

The pressurizer code safety valves are provided with an indirect indication of valve position located in the control room. This indication is derived from temperature detectors installed in the discharge piping of each safety valve. A high temperature annunciator is provided to warn of a leaking/lifting valve.

The power-operated relief valves are also equipped with a single temperature detector downstream. A high temperature annunciator is provided to warn of a leaking/lifting valve. This system is common to both power-operated relief valves. The power-operated relief valves are equipped with redundant limit switches that provide indication of the valves being fully closed, fully open, or some intermediate position.

In addition to the above methods of monitoring valve position, the code safety valves have been equipped with acoustic sensors. Two sensors are attached to the discharge piping of each valve. One of the sensors provides active indication of flow through the valve while the other sensor is used in a passive backup capacity, capable of being utilized if necessary. The operator is alerted to a detection of flow through a valve via a flashing annunciator. The specific valve causing the annunciator alarm can be determined by an indication on the acoustic monitoring panel located in the cable spreading room. The system is powered from either Unit 1 or Unit 2 semi-vital bus with automatic transfer on loss of either unit’s power via voltage monitoring relays.

One relief valve in the discharge piping of the RHR pumps provides a small degree of relief capacity in the event of an overpressure transient during RHR operation. The water relief capacity of the valve is 750 gpm at a backpressure of 5 psig. The RHR system relief valve is set at 600 psig and has no automatic isolation.

The pressurizer relief tank is protected against a steam discharge exceeding the design pressure value by rupture disks that discharge into the reactor containment. The rupture disk relief conditions are given in Table 4.1-3. The rupture disks are also designated as safety heads.

4.2.4 Protection Against Proliferation of Dynamic Effects

Essential operating and protective systems are protected from loss of function due to dynamic effects and missiles that might result from a pipe rupture[1]. Protection is provided by missile shielding and/or segregation of redundant components.

The reactor coolant system is surrounded by concrete shield walls. These walls provide shielding to permit access into the containment during full-power operation for inspection and maintenance of selected equipment. These shielding walls also provide missile protection for the containment liner plate.

The concrete covering over the reactor coolant system and the concrete floor under the reactor coolant system also provides for shielding and missile protection.

Steam generator restraints are provided at the upper support ring to resist lateral loads resulting from seismic and main steam line pipe rupture forces.

Missile protection afforded by the arrangement of the reactor coolant system is illustrated in the containment structure drawings given in Section 15.1. As can be seen from these drawings, protection against dynamic effects results from separation of loops by compartment walls.

4.2.5 Materials of Construction

Each of the materials used in the reactor coolant system was selected for the expected environmental and service conditions. The major component materials are listed in Table 4.2-1.

All materials that are exposed to the reactor coolant are corrosion-resistant. They were chosen for specific purposes at various locations within the system and for their superior compatibility with the reactor coolant. The chemical composition of the reactor coolant is maintained within the specification given in Table 4.2-2. Reactor coolant chemistry is further discussed in Section 4.2.8. Secondary chemistry is discussed in Section 10.3.5.

The phenomena of stress-corrosion cracking and corrosion fatigue are not encountered in these materials unless a specific combination of conditions is present. The necessary conditions are a metallurgically susceptible alloy, an aggressive environment, stress, and time.

Unit 1 reactor vessel closure head has been replaced with a closure head designed for a French nuclear power plant of similar design. The code for the replacement closure head materials was the French R-CCM Code. Equivalence documents were prepared to identify equivalent ASME Code materials. Table 4.2-1 summarizes the major component materials for the closure head and provides ASME equivalent materials where appropriate. RCCM/ASME Equivalency Report - Base Materials (Reference 11) provides ASME equivalent base materials used for the

1. As discussed in Section 15.6.2, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop piping or select reactor coolant system branch piping sections for the 80 year period of extended plant operations. However, other pipe ruptures as discussed in Section 15.6.2 must still be considered.

pressure boundary (including structural attachments). RCCM/ASME Equivalency Report - Filler Materials (Reference 12) provides ASME equivalent of the filler materials used for pressure boundary and attachments welded on the closure head. RCCM/ASME Equivalency Reports - Base Materials and RCCM/ASME Equivalency Reports for Filler Metals provides analysis and justification for deviations identified in the base materials and filler materials equivalency reports (References 11 & 12).

It is characteristic of stress corrosion that combinations of alloy and environment that result in cracking are usually quite specific. Environments that have been shown to cause stress-corrosion cracking of stainless steels are free alkalinity in the presence of a concentrating mechanism, and the presence of chlorides and free oxygen. With regard to the former, experience has shown that deposition of chemicals on tube surfaces can occur in a steam-blanketed area within a steam generator. In the presence of this environment, stress-corrosion cracking can occur in stainless steels having only the nominal residual stresses resulting from normal manufacturing procedures. However, the steam generator contains Inconel tubes. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions indicates that the Inconel alloy used has excellent resistance to general and pitting-type corrosion in severe operating water conditions.

The use of lead in the materials of the secondary side of the station is minimized except for that occurring as an insignificant trace element in metallurgical alloys.

All external insulation of reactor coolant system components is compatible with the component materials. The cylindrical shell exterior and closure flanges to the reactor vessel are insulated with metallic reflective insulation. The closure head is insulated with low halide-content insulating material. All other external corrosion-resistant surfaces in the reactor coolant system are insulated with inhibited low-halide or halide-free insulating material as required.

The stress limits established for the reactor vessel are dependent upon the temperatures at which the stresses are applied. As a result of fast neutron irradiation in the region of the core, the material properties change, including an increase in the NDTT. This was discussed in Section 4.1.7. An NDTT no greater than 40°F was set as the design limit. The material was tested to verify conformity to specified requirements and to determine the actual NDTT value. In addition, this plate was 100% volumetrically inspected by ultrasonic test using both longitudinal and shear wave methods.

The remaining material in the reactor vessel and other reactor coolant system components meets the appropriate design code requirements and specific component function.

The reactor vessel material was heat-treated specifically to obtain good notch-ductility. This ensured a low NDTT, and thereby gave assurance that the finished vessel could be initially hydrostatically tested and operated as near to room temperature as possible without restrictions.

The techniques used to measure and predict the integrated fast neutron (E greater than 1 MeV) fluxes at the sample locations are described in Section 4.1.7. The calculation method used to obtain the maximum neutron (E greater than 1 MeV) exposure of the reactor vessel is identical to that described for the irradiation samples. Since the neutron spectra at the samples are applied with confidence to the adjacent section of reactor vessel, the maximum vessel exposure is obtained from the measured sample exposure by appropriate application of the calculated azimuthal neutron flux variation.

The calculated maximum fast neutron fluence to the reactor vessel beltline (E greater than 1 MeV) after 80 years of operation (68 EFPY) is 6.35 × 1019 n/cm2 and 7.26 × 1019 n/cm2 for Units 1 and 2, respectively. When calculated in the manner prescribed by Regulatory Guide 1.99, Revision 2, Topical Report BAW-2308, Revision 1-A and Topical Report BAW-2308, Revision 2-A, the limiting values of RTNDT are predicted to occur in the Unit 1 lower shell longitudinal weld L2 at the 1/4-T location and the Unit 2 intermediate to lower shell circumferential weld at the 3/4-T location. For the purposes of pressure-temperature limit curve development, conservative bounding 1/4T and 3/4T RTNDT values of 228.4°F and 189.5°F, respectively, were utilized corresponding to a prior analysis of the Surry Unit 1 Intermediate to Lower Shell Circumferential Weld. Unirradiated RT_{NDT} values for reactor vessel materials are presented in Tables 4.1-14 and 4.1-15. Data used in the original design assessment of radiation-induced transition temperature increases is presented in Table 4.2-3 and Figure 4.2-9.

To evaluate the RT_{NDT} shift of welds, heat-affected zones, and base material for the vessel, test coupons of these material types are included in the reactor vessel surveillance program described in Section 4.1.7.

4.2.6 Maximum Heat-Up and Cooldown Rates

The reactor coolant system operating cycles used for design purposes are given in Table 4.1-8 and described in Section 4.1.4. During unit heat-up and cooldown, the rates of temperature and pressure changes are limited. The system design heat-up and cooldown rate of 100°F/hr satisfies stress limits for cyclic operation (ASME Vessel Code, Section III) and is consistent with the expected number of cycles. However, the normal system heat-up and cooldown rates are conservatively set at 50°F/hr. Sufficient electrical heaters are installed in the pressurizer to permit an adequate pressurizer heat-up rate of 55°F/hr when starting with a minimum water level and all pressurizer heaters in service. This rate takes into account the small continuous spray flow provided to maintain the pressurizer liquid homogeneous with the coolant.

The heat-up and cooldown rate for the pressurizer should not exceed 100°F/hr and 200°F/hr, respectively. A maximum temperature difference of 303°F between the pressurizer and reactor coolant hot leg is specified to maintain thermal stresses and fatigue in the surge line below design limits. Pressurizer spray should not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F.

The fastest cooldown rates, which result from the hypothetical case of a break of a main steam line, are discussed in Section 14.3.2.

4.2.7 Leakage

4.2.7.1 Leakage Detection

Coolant leakage from the reactor coolant system to the containment is indicated in the control room by one or more of the following methods:

1. The containment air particulate monitoring system - A system is provided to monitor particulate activity from the areas enclosing the reactor coolant system components so that any leakage from them can be easily detected. Experience has shown that the containment air particulate monitoring system responds rapidly to primary system leakage and will provide a sensitive indication of such leakage. The curves in Figure 4.2-10 indicate the air particulate monitor response times as a function of percentage of failed fuel and rate of coolant leakage. For example, the curves indicate, for 1% failed fuel, monitor response times of approximately 20 minutes, 6 minutes, and 2 minutes for assumed leakage rates of 10, 100, and 1000 cm^3/min, respectively. Lesser quantities of failed fuel will, of course, result in increasingly longer response times.

   In the range of percent failed fuel covered by Figure 4.2-10, the effect of activated corrosion products is negligible. If there is no failed fuel, the containment air particulate monitor will still detect a leak, if there are sufficient activated corrosion products present in the reactor coolant. With equilibrium activated corrosion products present in the reactor coolant, a leak of 1000 cm^3/min would be detected in less than 4 hours. Lesser quantities of activated corrosion products will result in increasingly longer response times.

   The containment air particulate monitor is indicated, recorded, and alarmed in the control room.

2. The containment gas monitor - A system is provided to monitor gaseous activity from areas enclosing the reactor coolant system. Even though the gas monitor itself is less sensitive than the particulate monitor, the gaseous activity from any leakage is expected to be higher than the particulate activity, so that the gas monitor will also be sensitive to a leak. The containment gas monitor is indicated, recorded, and alarmed in the control room.

   The capability and sensitivity of the containment gas monitor to detect primary coolant system leakage is highly dependent on the operating condition of the plant. The following three cases illustrate this:

   Case 1. If there is no prior leakage into the containment and the primary coolant gaseous activity is a maximum (about 200 $\mu Ci/cm^3$), a leak of 0.1 gpm can be easily detected in less than 30 minutes.

Case 2. If there is no prior leakage into the containment and the primary coolant gaseous activity is 0.6 $\mu Ci/cm^3$ (typical of operating pressurized-water reactors), a 1-gpm leak should be detected within 2 hours.

Case 3. If there is prior continuing leakage of 0.5 gpm into the containment and the containment gas monitor high radiation alarm setting is twice the existing steady state activity in the containment, it will take about 60 hours to detect a 2-gpm leak and 1 hour to detect a 100-gpm leak, as shown in Figure 4.2-11.

3. Abnormal makeup water requirements - Any leakage will cause an increase in the amount of makeup water required to maintain normal level in the pressurizer. The primary-grade water and concentrated boric acid makeup flow rate are both recorded and alarmed in the control room.

4. Containment instrumentation - The reactor containment sump level instrumentation and the containment pressure and temperature instrumentation could all indicate leakage in the containment, but not necessarily from the primary coolant system. These measurements are also subject to variations unrelated to leakage from ruptured fluid systems. The instruments all indicate in the control room; however, it is not the primary purpose of the containment sump level and containment pressure or temperature instrumentation to detect primary coolant system leakage. Primary coolant system leakage can be most readily detected by increased makeup requirements to the primary coolant system and by the containment gas monitors.

   The containment pressure and temperature are recorded by the data logger. The containment pressure also alarms in the control room.

5. Reactor vessel leakoff - Leakage through the reactor vessel head flange will leak off between the double o-ring seal to the leakoff provided. Leakage into this leakoff will cause high temperature in this line, which will actuate an alarm in the control room.

Methods 1 and 2 can only be used for leakage detection if there are sufficient activated products in the reactor coolant. If there are no such activated products in the reactor coolant, the other methods can be used to detect a leak.

In accordance with the information provided in Reference 2, and the safety evaluation of Reference 3, it was concluded that the reactor coolant leakage detection capability meets the staff guidelines of 1 gpm in 4 hours.

4.2.7.2 **N-16 Primary to Secondary Leakage Detection System**

There are three N-16 leak detection channels per unit. The detectors are located adjacent to each of the main steam lines in the Mechanical Equipment Room (MER). They continuously monitor main steam and provide indication locally via Local Processing Display Units (LPDUs). The LPDUs provide a leakrate signal to a recorder remotely in the control room for each unit. The N-16 recorder is located in the main control board vertical section. They provide a digital indication up to 1000 gallons per day of primary to secondary leakage as well as trending information. Alarm inputs are provided to the control room annunciator cabinet to alert operators of steam generator leakage and also provide an operational fault alarm in case of an internal malfunction in an N-16 channel. All LPDUs are mounted in the cable spreading rooms.

The N-16 leak detection systems are designed for continuous operation. Continuous, as used to describe the operation of the N-16 leak detection systems, means that the monitors provide the required information at all times except when the system is out of service for testing or maintenance and approved alternate monitoring methods are in place.

The N-16 leak detection system is an indicating system and does not interact with any plant controlling system. Each steam generator N-16 channel provides an input to the ERF data acquisition system. The N-16 channel information is displayed on the plant computer system.

4.2.7.3 **Leakage Prevention**

Reactor coolant system components are manufactured to normal code requirements as outlined in Section 4.1.6. Leakage through metal surfaces or welded joints is unlikely because of the welded construction of the reactor coolant system and the extensive non-destructive testing to which it is subjected.

Some leakage from the reactor coolant system is permitted by the reactor coolant pump seals. Also, all sealed joints are potential sources of leakage even though the most appropriate sealing device is selected in each case. Because of the large number of joints and the difficulty of ensuring complete freedom from leakage in each case, a small integrated leakage is considered acceptable.

All valves 3 inches or larger in lines connecting to the reactor coolant system which are normally subjected to reactor coolant system operating conditions are provided with leakoff connections. Some of these valves are equipped with backseats which limit leakage.

4.2.7.4 **Locating Leaks**

Experience has shown that hydrostatic testing is successful in locating leaks in a pressure-containing system.

Methods of locating leaks during a station shutdown include visual observation for escaping steam or water, or of boric acid crystals near the leak. The boric acid crystals are transported outside the reactor coolant system in the leaking fluid and deposited by the evaporation process.

4.2.8 Water Chemistry

The reactor coolant system water chemistry is selected to provide the necessary boron content for reactivity control and to minimize corrosion of reactor coolant system surfaces.

All materials exposed to reactor coolant are corrosion-resistant. Periodic analyses of the coolant chemical composition monitor the adherence of the system to the reactor coolant water quality listed in Table 4.2-2. Maintenance of the reactor coolant system water quality to minimize corrosion is accomplished using the chemical and volume control system and the sampling system, which are described in Sections 9.1 and 9.6, respectively.

4.2.9 Reactor Coolant Flow Measurements

Both the calculated system pressure drop and the pump design head contain sufficient margin to ensure a system flow rate equal to or greater than design flow rate. Straightforward hydraulics techniques are employed, together with detailed model tests using scaling techniques in accordance with Hydraulic Institute standards. This design approach has been substantiated by measurements in operating Westinghouse-designed plants.

Core safety limits are not particularly sensitive to the absolute value of reactor coolant system flow. In the course of the initial unit start-up, data pertinent to determining coolant flow, both directly and indirectly, were obtained to verify that flow was not less than design. A definite exact measurement of flow is not necessary for unit operation or for protection system purposes. Further, there are no design provisions to vary flow, e.g. throttling devices; thus variations in absolute flow are not of concern during operation. Protection in the event of a loss of flow resulting from loss of power to one or more pumps is analyzed in Section 14.2.9.

Two methods are used in the station to measure reactor coolant system flow rate. These methods supplement each other to confirm that system flow is equal to or greater than design flow.

The methods discussed below consist of (1) a secondary heat balance coupled with coolant temperatures, and (2) elbow tap differential pressure measurements.

4.2.9.1 **Secondary Heat Balance**

Reactor coolant system flow rate is calculated by accurately measuring the secondary system power generation together with the corresponding measured hot-leg to cold-leg temperature differential in the reactor coolant system (loop delta T). Flow is equal to power divided by the reactor coolant enthalpy decrease.

4.2.9.2 **Elbow Tap Differential Pressure**

Measurement of the elbow tap flow meter differential pressure provides a highly repeatable measure of flow rate. The flow rate is determined from the measured 90-degree elbow differential pressure by documented (Reference 4) standard elbow characteristics.

4.2.9.3 **Experience**

Each of the above methods is employed to obtain an independent assessment of flow. Both are evaluated in terms of consistency, one with another, as well as between loops. Possible error allowances are established on the basis of various in-plant calibrations, e.g., loop temperature. Experience has shown that all methods used indicate greater than design flow, with good agreement between loops and reasonable agreement between methods sufficient to validate greater than design flow.

4.2.9.4 **Low-Flow Trip Setpoint**

Elbow taps are used in the reactor coolant system as an instrument device that indicates the status of reactor coolant flow. The basic function of this device is to provide information as to whether a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap readout has been well established by the following equation (Reference 4):

$$\frac{\Delta P}{\Delta P_o} = \left(\frac{\omega}{\omega_o}\right)^2$$

Where:

ΔP_o = referenced pressure differential

ω_o = referenced flow rate

ΔP = pressure differential

ω = flow rate

The full-flow reference point was established during initial unit start-up. The low-flow trip point was then established by extrapolating along the correlation curve. The technique has been used in providing core protection against low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within ±10%. Field results have shown the repeatability of the trip point to be within ±1%. The analysis of the loss-of-flow transient presented in Section 14.2.9 assumes an instrumentation error of ±3%.

4.2.10 Loose Parts Monitoring System

The undetected presence of loose parts or other solid objects circulating in the primary system or secondary, side of the steam generators represents an undesirable situation with regard to potential safety concerns such as flow blockage, core reactivity control, fuel damage, and degradation of the primary system pressure boundary. In addition, there is a concern over possible component damage and degradation of service life due to the impact and abrasion of the loose parts. For this reason, a loose parts monitoring system has been installed to provide the ability to monitor the primary system and secondary side of the steam generators for the presence of loose circulating parts and other foreign objects.

4.2.10.1 **Design Criteria**

The loose parts monitoring system was designed and installed in accordance with the requirements of the appropriate edition of the ASME Code, Section III or XI, as applicable. All attachment clamps have been seismically analyzed to prevent possible damage to safety-related equipment in the event of a seismic event. The loose parts monitoring system cabinet has also been seismically analyzed and seismically mounted and supported.

The loose parts monitoring system is a non-safety-related system. The system has been reviewed for environmental qualification, and it has been determined that the requirements of IE Bulletin 79-01B, NUREG-0588, and IEEE 323-1974 are not applicable. Redundancy requirements are not applicable to the loose parts monitoring system but spare channels are provided in case of instrument channel failure.

With the exception of the hard-line cable, which is Category III, the cable in the loose parts monitoring system is Category I, Class 1E, nuclear grade, flame retardant, and qualified for its intended service conditions. The hard-line cable from the reactor vessel head is routed so that it does not endanger the seismic requirements of other devices located on the reactor vessel head.

4.2.10.2 **System Description**

The loose parts monitoring system provides the operator a means to detect and monitor the presence of a loose part or other solid object circulating freely in the primary or secondary system.

The loose parts monitoring system installed on each unit consists of 10 accelerometers, an amplifier cabinet with associated electronics, and remote alarm annunciators located in the control room. Two accelerometers are located on the reactor vessel head, two on the reactor vessel thimble tubes, one on the primary side of each of the steam generators and one on the secondary side of each steam generator.

Each accelerometer is routed to a line driver, via hardline cable, with the output of the line driver connected to twisted pair cable. The twisted pair cable is routed to the containment penetration and then to the cabinet input terminal block.

The output of each accelerometer and signal conditioner is monitored by a master alarm module. If an accelerometer detects a loose part, an alarm contact is actuated which alerts the operator to a potential loose part.

4.2.11 Loss of Decay Heat Removal

Generic Letter 88-17, *Loss of Decay Heat Removal,* concerns the difficulties and potential consequences involved in preventing, and in recovering from, a loss of cooling to the core while the unit is shut down (References 5 though 10). The concern resulted in several initiatives to ensure adequate protection from a loss of shutdown cooling, especially during reduced inventory conditions. Reduced inventory is defined to be a RCS level lower than three feet below the reactor vessel flange. This corresponds to an inventory level of 15.7 feet elevation.

Adequate indication of RCS level and temperature, and of RHR system performance, is provided in the control room. A permanent RCS standpipe and an ultrasonic level detector are installed to ensure that at least two independent, continuous RCS level indications are monitored in the control room during reduced inventory conditions. Both level monitors provide indication, trending, and low-level alarms in the control room. Whenever the reactor vessel head is located on the reactor vessel, prior to draining the RCS to a reduced inventory condition, at least two core exit thermocouple (CET) temperature indicators are demonstrated to be operable. The CETs continuously indicate in the control room and are periodically recorded on the control room shutdown logs. When the CETs are disconnected due to vessel disassembly, the RHR system temperature indication remains operable and available in the control room. Continuous monitoring of the RHR system performance is provided in the control room by these instruments: suction and discharge temperature indication and trend recording, system flow indication, MOV position indication when energized, pump current indication, pump breaker status indication, system low-flow alarm, pump auto-trip alarm, pump discharge high-pressure alarm, pump cooling water low flow alarm and component cooling status (e.g. temperature, flow and pump current).

Controls are in place to implement specific actions to be taken when draining the RCS. Those actions are based on the Westinghouse Owners Group reduced inventory project guidance and additional plant-specific analyses. The analyses consider the variables affecting time to core boiling, including RCS inventory, RCS temperature, time since shutdown, and total decay heat inventory. The analyses provide the necessary information to determine equipment and operation requirements or limitations, including:

1. Prior to entering a reduced inventory condition, controls are established to provide reasonable assurance containment closure can be achieved prior to the time core boiling could result from a loss of decay heat removal. During reduced inventory conditions, at least one boundary on each containment penetration is maintained intact, with the exception of penetrations in use or undergoing maintenance which are under administrative control. In the event of a loss of decay heat removal, a containment closure team is responsible for closing the administratively controlled penetrations.

2. Prior to entering a reduced inventory condition, one charging pump and one low head safety injection pump are maintained available with a specified flowpath to the core. Administrative controls ensure that additional means of shutdown cooling or inventory make-up are also available.

3. Whenever possible in a reduced inventory condition, activities are avoided that could disrupt stable conditions in the RCS or RHR system, or compensatory actions are taken. Maintenance activities are assessed prior to implementation for their potential to cause a loss of RCS inventory. Procedures include measures to prevent a loss of RHR and to enhance monitoring for early diagnosis of a loss of RHR.

4. To ensure that pressurization of the reactor vessel upper plenum does not occur upon a loss of cooling, procedures require that the cold leg isolation valve shall be closed first when isolating an RCS loop. When returning an RCS loop to service, the hot leg isolation valve shall be opened first. Whenever maintenance requires an opening on the cold leg during

reduced inventory operation, procedural controls are in place to ensure a sufficient vent path is available.

These actions are adequate to ensure that decay heat removal capability is maintained.

4.2 REFERENCES

1. Letter from NRC to Vepco, Subject: *Steam Generator Program, Surry Power Station, Units 1 and 2,* dated August 17, 1977, Ser. No. 351.
2. Letter from Vepco to NRC, Subject: *Request for Partial Exemption from General Design Criteria 4 - Supplement,* dated December 3, 1985 (Serial No. 85-136A).
3. Letter from NRC to Vepco transmitting Surry Unit 1 and 2 License Amendments No. 108 and related safety evaluations, dated June 16, 1986.
4. J. W. Murdock, "Performance Characteristic of Elbow Flowmeters," *Transactions of the ASME*, September 1964.
5. VEPCO Letter Serial No. 88-737, *Response to Generic Letter 88-17 Loss of Decay Heat Removal,* dated January 6, 1989.
6. VEPCO Letter Serial No. 88-737A, *Response to Generic Letter 88-17 Loss of Decay Heat Removal,* dated February 3, 1989.
7. VEPCO Letter Serial No. 88-737C, *Generic Letter 88-17: Loss of Decay Heat Removal Programmed Enhancements for Instrumentation,* dated October 3, 1989.
8. VEPCO Letter Serial No. 88-737E, *Supplemental Response Generic Letter 88-17, Loss of Decay Heat Removal,* dated October 5, 1990.
9. VEPCO Letter Serial No. 88-737D, *Supplemental Response to Generic Letter 88-17 Loss of Decay Heat Removal,* dated November 16, 1990.
10. VEPCO Letter Serial No. 91-447, *NRC Generic Letter 88-17, Loss of Decay Heat Removal Implementation of Programmed Enhancements,* dated November 14, 1991.
11. Framatome ANP Document No. 38-5026914, *RCCM/ASME Equivalency Report - Base Materials for Surry Unit 1 Reactor Vessel Closure Head.*
12. Framatome ANP Document No. 39-5026915, *RCCM/ASME Equivalency Report - Filler Materials for Surry Unit 1 Reactor Vessel Closure Head.*

4.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-086A	Flow/Valve Operating Numbers Diagram: Reactor Coolant System; Loops A, B, & C; Unit 1
	11548-FM-086A	Flow/Valve Operating Numbers Diagram: Reactor Coolant System; Loops A, B, & C; Unit 2
2.	11448-FM-086B	Flow/Valve Operating Numbers Diagram: Reactor Coolant System, Unit 1
	11548-FM-086B	Flow/Valve Operating Numbers Diagram: Reactor Coolant System, Unit 2

Table 4.2-1
REACTOR COOLANT SYSTEM MATERIALS OF CONSTRUCTION

Component	Section	Materials
Reactor vessel	Plate	ASTM A-533B Class 1
	Forgings	ASTM A-508 Class 2
	Cladding	SS 304 equivalent and Inconel SA B166 equivalent
Unit 1 closure head	Plate	SA-533 Type B Class 1 R-CCM 16 MND 5 (M2122)
	Forgings	SA-508 Grade 3 Class 1 R-CCM 16 MND 5 (M2113)
	Cladding	ER 309L 1st Layer ER 308L Subsequent layers
Unit 2 closure head	Forging	SA508, Grade 3, Class 1
	Cladding	SS 304 equivalent
Steam generator	Plate	ASTM A-533A Class 1 [a]
	Forgings (tubesheet)	ASTM B-508 Class 2a
	Cladding	SS 304 equivalent
	Cladding for tubesheets	Inconel
	Tubes	ASTM B-163, thermally treated
	Support plates	ASTM A-240 type 405
	Channel head castings	ASTM A-216 Grade WCC
Pressurizer	Shell	SA 302 Grade B
	Heads	SA 216 Grade WCC
	Support skirt	SA 516 Grade 70
	Nozzle weld ends [b]	SA 182 type 316
	Sockets	SA 182 F316
	Cladding	SS 304 equivalent
	Internal plate	SA A-240 type 304
	Heat tubing	SA 213 type 316
Pressurizer relief	Shell	ASTM A-285 Grade C
Tank	Heads	ASTM A-385 Grade C

a. ASTM A-533 is equivalent to ASTM A-302B. ASTM A-302B data presented elsewhere in this report are applicable to ASTM A-533B.
b. Unit 2 surge nozzle end is SA 312 type 316. All instrument and sample nozzle ends are SA 276 type 316.

Table 4.2-1 (CONTINUED)
REACTOR COOLANT SYSTEM MATERIALS OF CONSTRUCTION

Component	Section	Materials
Piping	Pipes	ASTM A-376 type 316
	Fittings	ASTM A-351 Group CF8M
	Nozzles	ASTM A-182 F316
Pump	Shaft	ASTM A-182 Grade F304
	Impeller	ASTM A-351 Grade CF8
	Casing	ASTM A-351 Grade CF8
Valves	Pressure-containing parts	ASTM A-351 Grade CF8M
Loop stop valves	Pressure-containing parts	ASTM A-351 Grade CF8M

Table 4.2-2
REACTOR COOLANT SYSTEM WATER CHEMISTRY SPECIFICATIONS[a]

Electrical conductivity	Determined by the concentration of boric acid and controlled chemicals present. Expected range is from less than 1 to 40 μMhos/cm at 25°C.
Solution pH	Determined by the concentration of boric acid and controlled chemicals present. Expected values range between 4.2 (high boric acid concentration) to 10.5 (low boric acid concentration) at 25°C.
Oxygen, max.[b]	0.1 ppm
Chloride, max.[b]	0.15 ppm
Fluoride, max.[b]	0.15 ppm
Hydrogen	5-50 cc (STP)/kg H_2O
Total suspended solid, max.	1.0 ppm
pH control agent (Li^7OH)	Determined by high temperature pH with concentration decreasing from approximately 3.5 ppm (as Li) at a RCS boron concentration of 2000 ppm until end of life cycle.
Boric acid, as ppm B	Design range from 0 - ≈ 4000

a. Applicable when the reactor is critical.

b. Refer to the Technical Specifications for applicability.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 4.2-3
RADIATION-INDUCED INCREASE IN TRANSITION TEMPERATURE FOR A302B STEEL

References[a]	Material	Temp., °F	Neutron Exposure, n/cm^2 (> 1 meV)	Change in NDTT, °F
1. NRL Report 6160, p. 12	SA302B	450	5×10^{18}	140
2. NRL Report 6160, p. 12	SA302B	550	5×10^{18}	65
3. NRL Report 6160, p. 13	SA302B	490	1.4×10^{19}	200
4. ASTM-STP 341, p. 226	SA302B	550	6×10^{17}	30[b]
5. ASTM-STP 341, p. 226	SA302B	550	6×10^{17}	45
6. ASTM-STP 341, p. 226	SA302B	550	8×10^{18}	85[b]
7. ASTM-STP 341, p. 226	SA302B	550	8×10^{18}	100
8. ASTM-STP 341, p. 226	SA302B	550	1.5×10^{19}	130[b]
9. ASTM-STP 341, p. 226	SA302B	550	1.5×10^{19}	140
10. NRL report 6160, p. 6	All steels	450	Various	Various
11. Nuclear Science and Engineering 19:18-38 (1964)	SA302B	450	Various	Various
12. Quarterly Report of Progress, *Irradiation Effects on Reactor Structural Materials* 11-1-64/1-31-64	SA302B	550	3×10^{19}	120
13. Quarterly Report of Progress, *Irradiation Effects on Reactor Structural Materials* 11-1-64/1-31-64	SA302B	550	3×10^{19}	135
14. Quarterly Report of Progress, *Irradiation Effects on Reactor Structural Materials* 11-1-64/1-31-64	SA302B	550	3×10^{19}	140
15. Quarterly Report of Progress, *Irradiation Effects on Reactor Structural Materials* 11-1-64/1-31-64	SA302B	550	3×10^{19}	170

a. Applicable to Figure 4.2-9.
b. Transverse specimens.
c. Plotted as a 550°F data point.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 4.2-3 (CONTINUED)
RADIATION-INDUCED INCREASE IN TRANSITION TEMPERATURE FOR A302B STEEL

References[a]	Material	Temp., °F	Neutron Exposure, n/cm^2 (> 1 meV)	Change in NDTT, °F
16. Quarterly Report of Progress, *Irradiation Effects on Reactor Structural Materials* 11-1-64/1-31-64	SA302B	550	3×10^{19}	205
17. NRL Report 6179, p. 9	SA302B	475-540	5×10^{19}	225
18. NRL Report 6179, p. 9	SA302B	475-540	7×10^{19}	260
19. NRL Report 6179, p. 9	SA302B	475-540	9×10^{19}	310
20. NRL Report 6179, p. 9	SA302B	475-540	5×10^{19}	320
21. NRL Report 6160, p. 15	SA302B	540[c]	4×10^{19}	200
22. NRL Report 6160, p. 15	SA302B	540[c]	3×10^{19}	165
23. Private communication with NRL	SA302B	550	3.8×10^{18}	160
24. Progress Report, No. 1, *Irradiation Tests on Reactor Pressure Vessels Steels in Br-3 Reactor Facilities*, August 1965	SA302B	≈525	5.4×10^{18}	54
25. Ibid.	SA302B	≈525	1.2×10^{19}	96
26. Progress Report, No. 1, *Irradiation Tests on Reactor Pressure Vessel Steels in Br-3 Reactor Facilities*, August 1965	SA302B	≈600	9.5×10^{19}	260
27. Ibid.	SA302B	≈ 600	2×10^{20}	360

a. Applicable to Figure 4.2-9.
b. Transverse specimens.
c. Plotted as a 550°F data point.

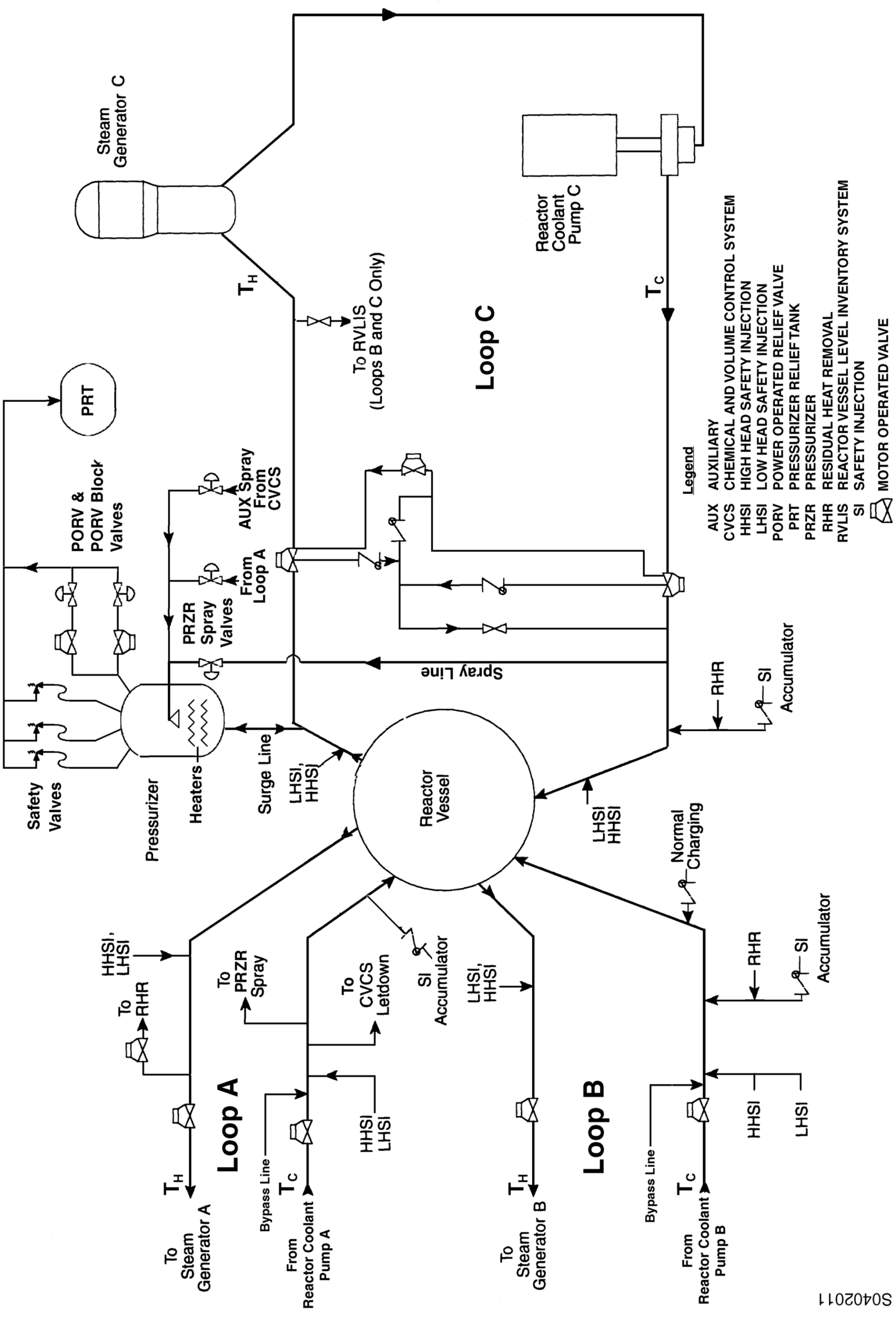
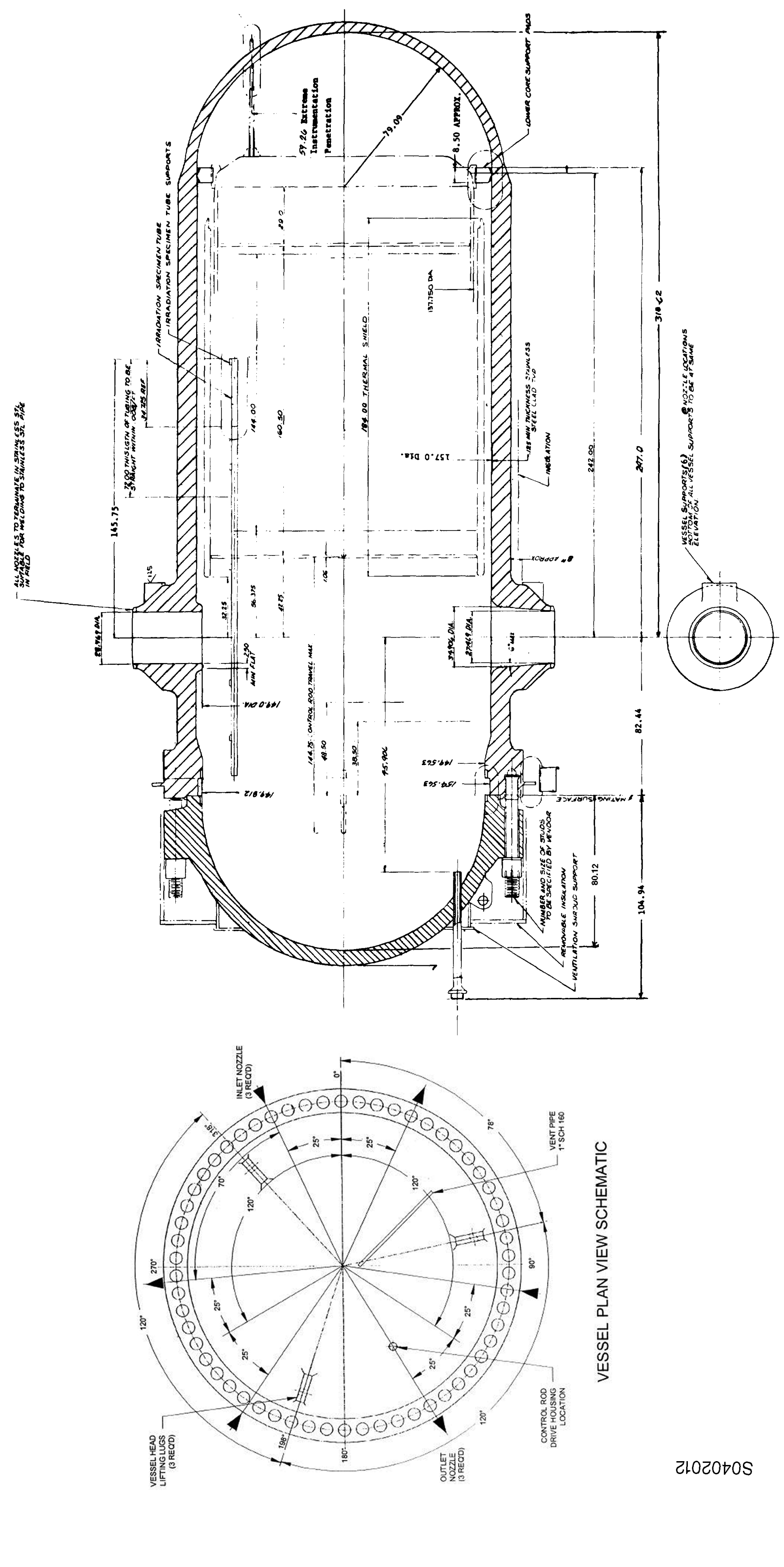


Figure 4.2-1
REACTOR COOLANT SYSTEM (UNIT 1)

Figure 4.2-2
REACTOR VESSEL SCHEMATIC (UNIT 1)



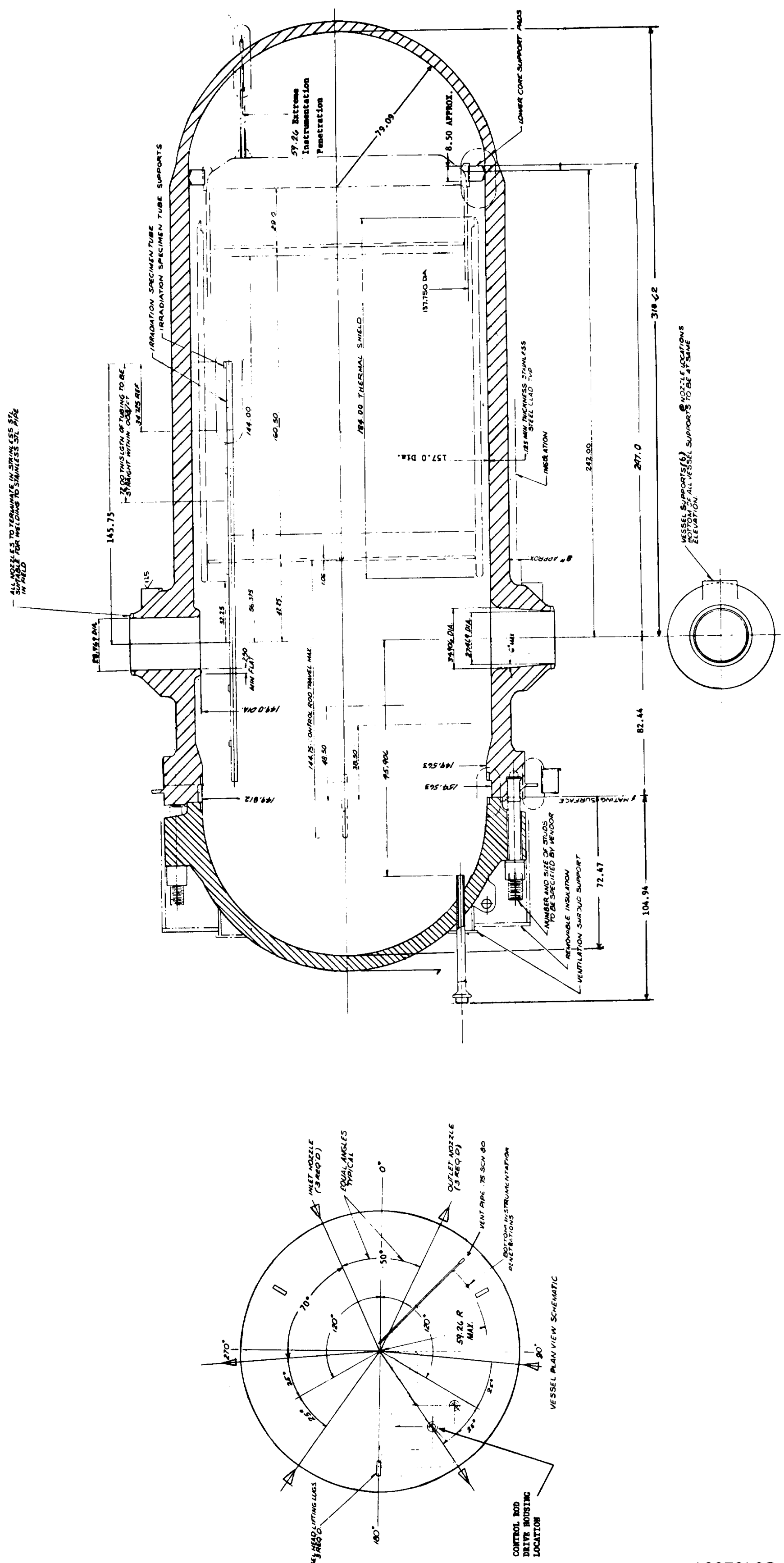


Figure 4.2-3
REACTOR VESSEL SCHEMATIC (UNIT 2)

S0402001

Figure 4.2-4
PRESSURIZER

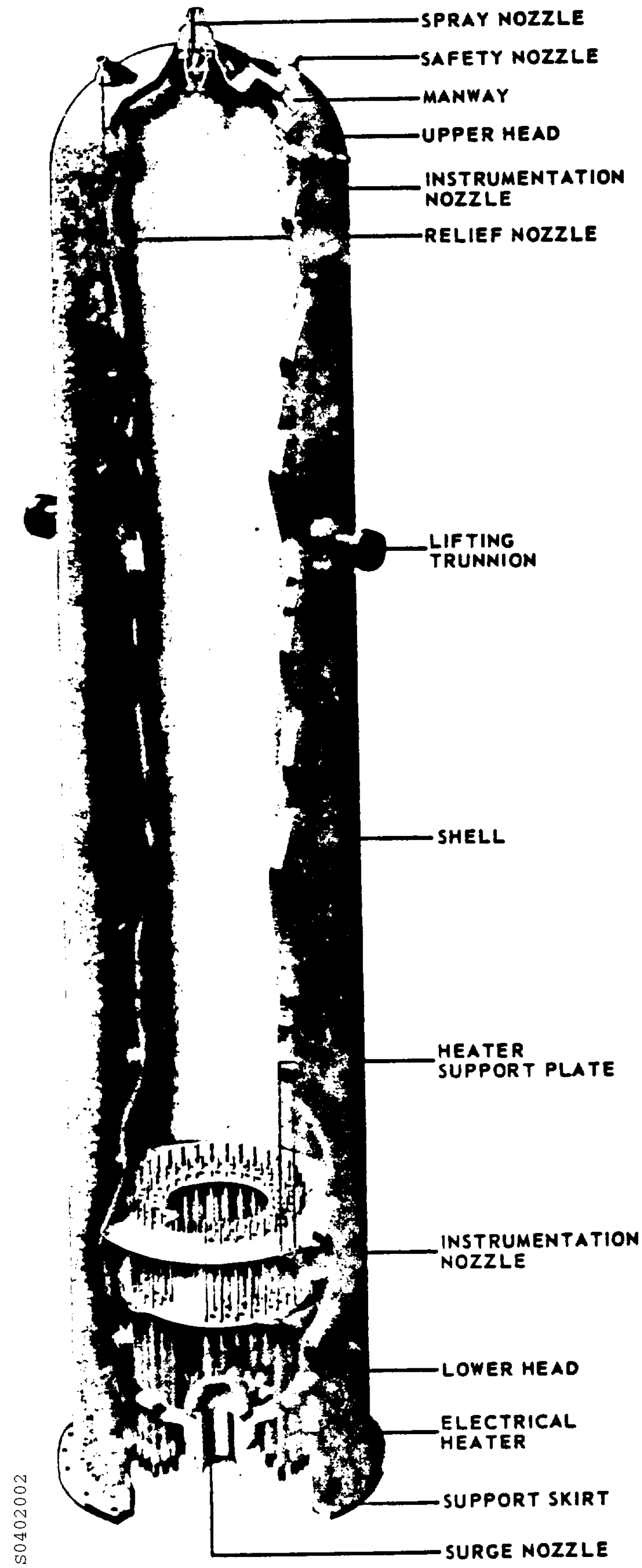


Figure 4.2-5
STEAM GENERATOR TUBE-TO-TUBESHEET JUNCTURE

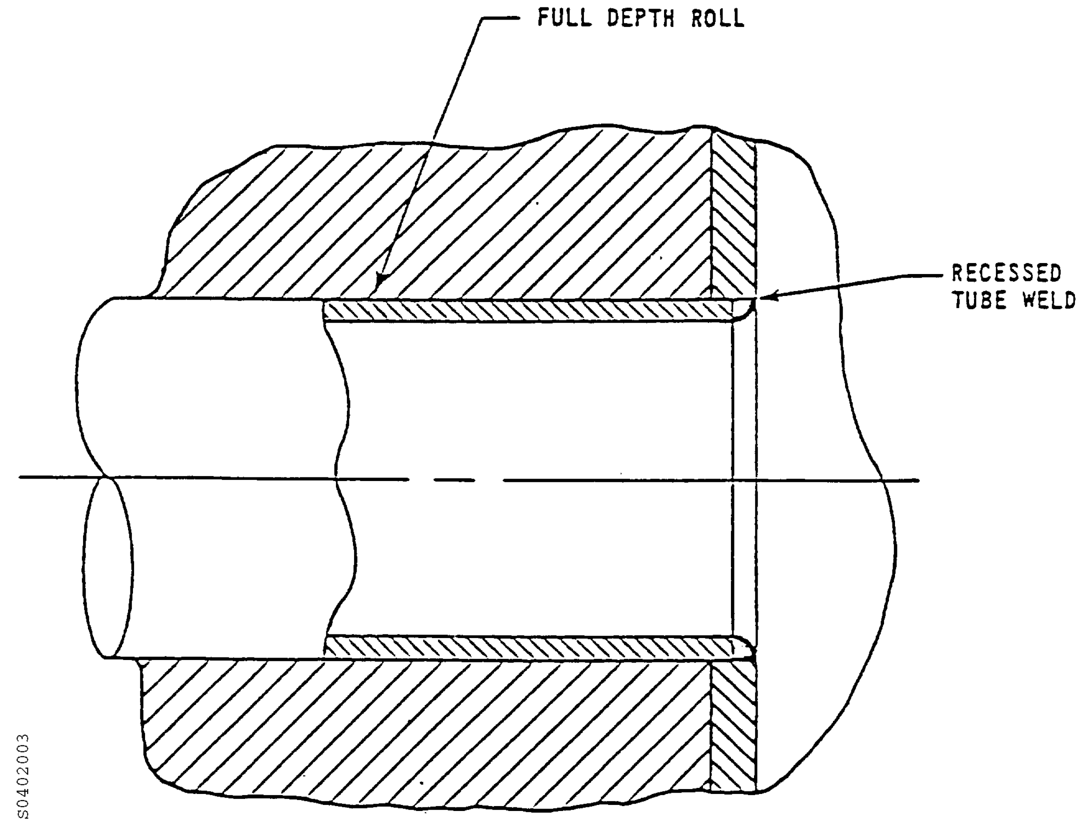


Figure 4.2-6
TYPICAL REACTOR COOLANT PUMP

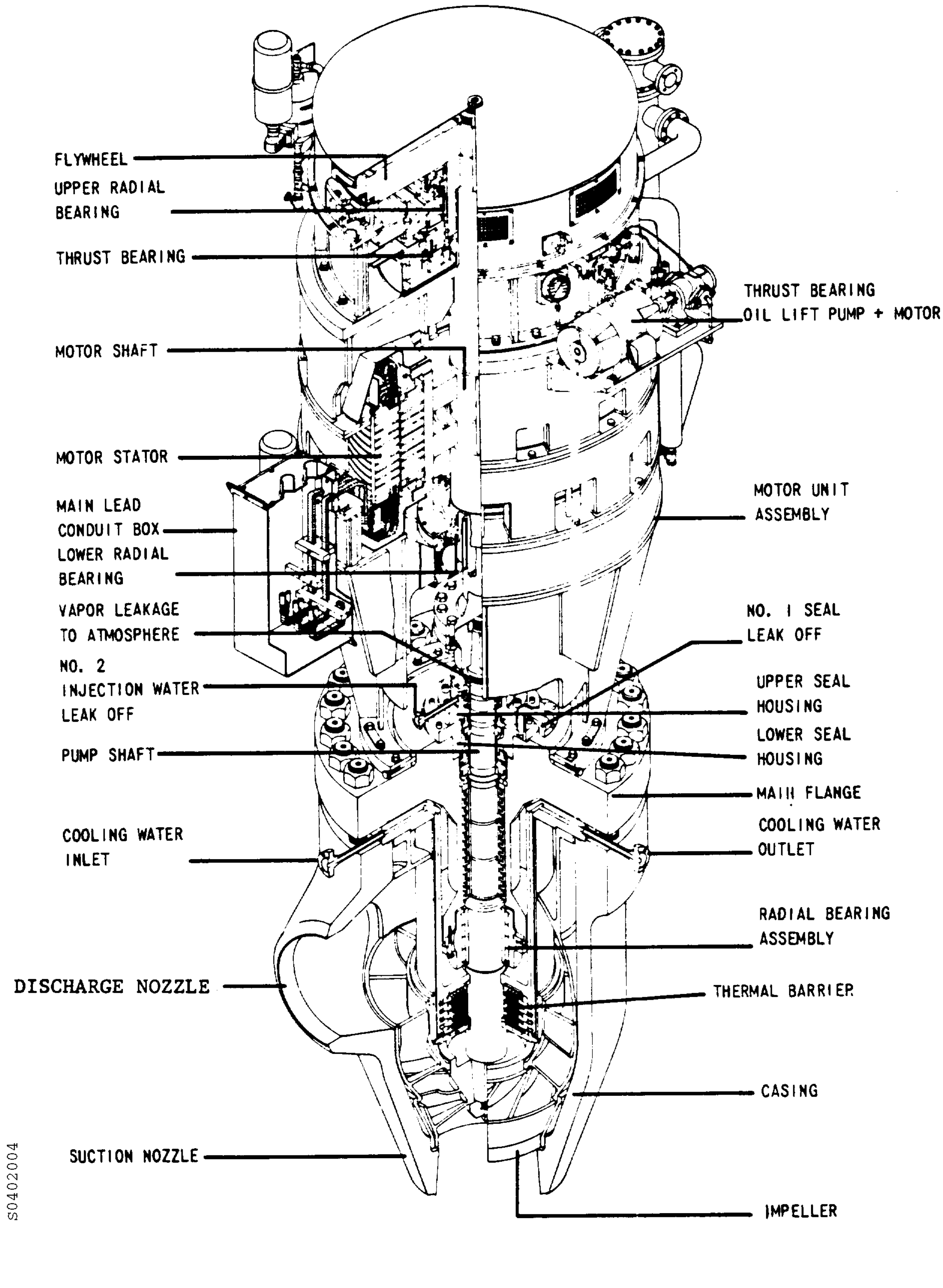


Figure 4.2-7
REACTOR COOLANT PUMP ESTIMATED PERFORMANCE CHARACTERISTICS

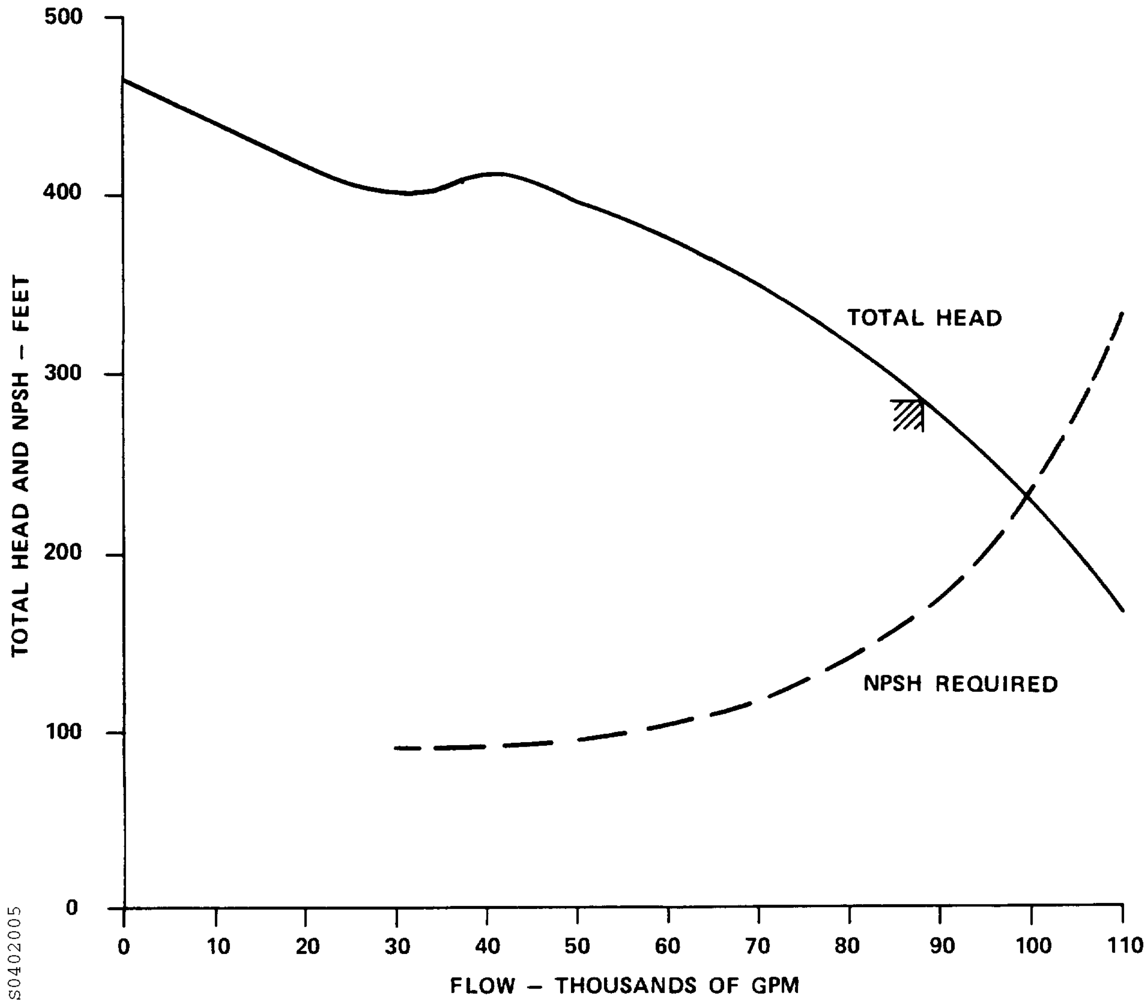
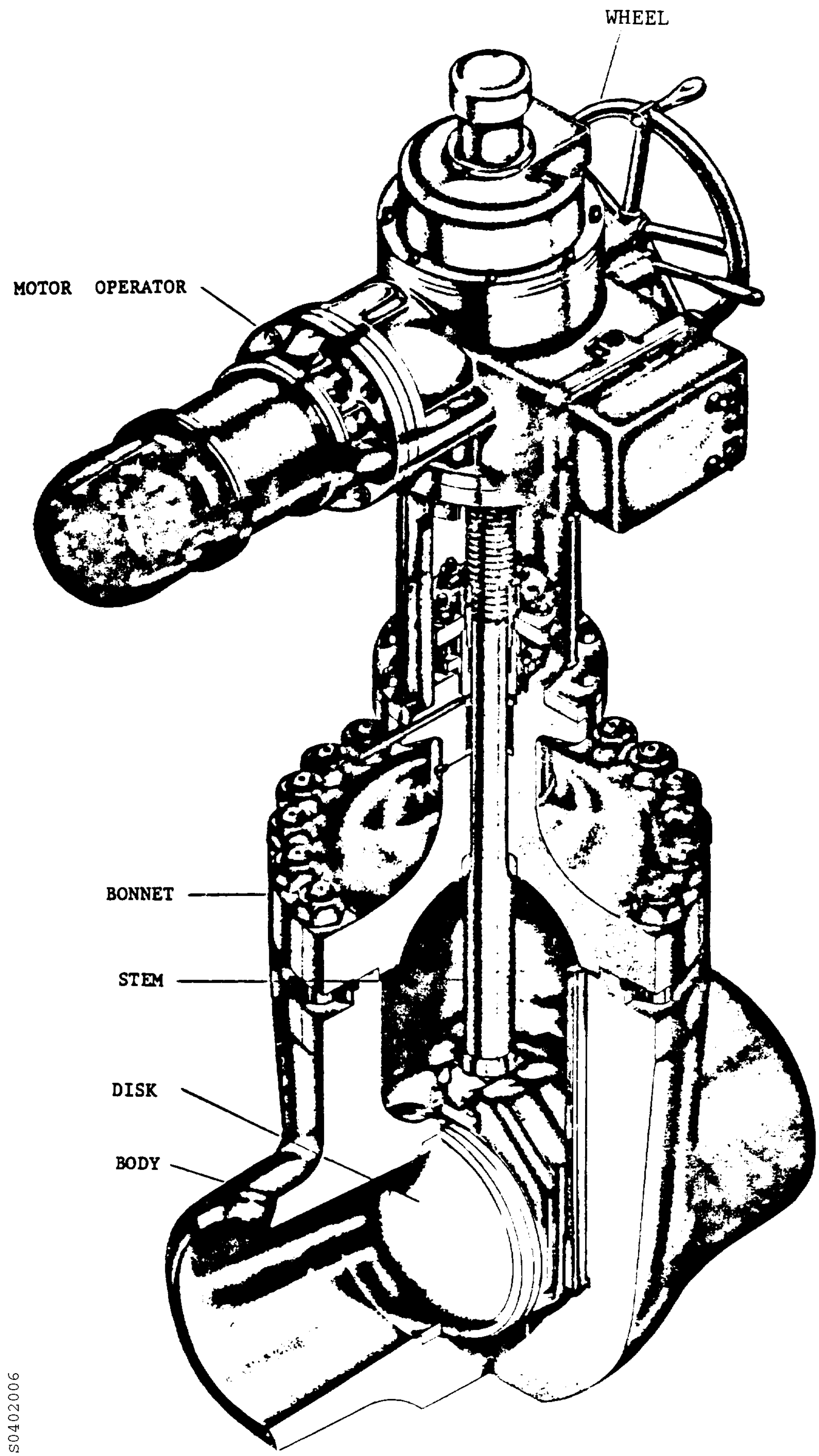


Figure 4.2-8
REACTOR COOLANT LOOP STOP VALVE



The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Figure 4.2-9
RADIATION INDUCED INCREASE IN TRANSITION TEMPERATURE FOR A 302-B STEEL

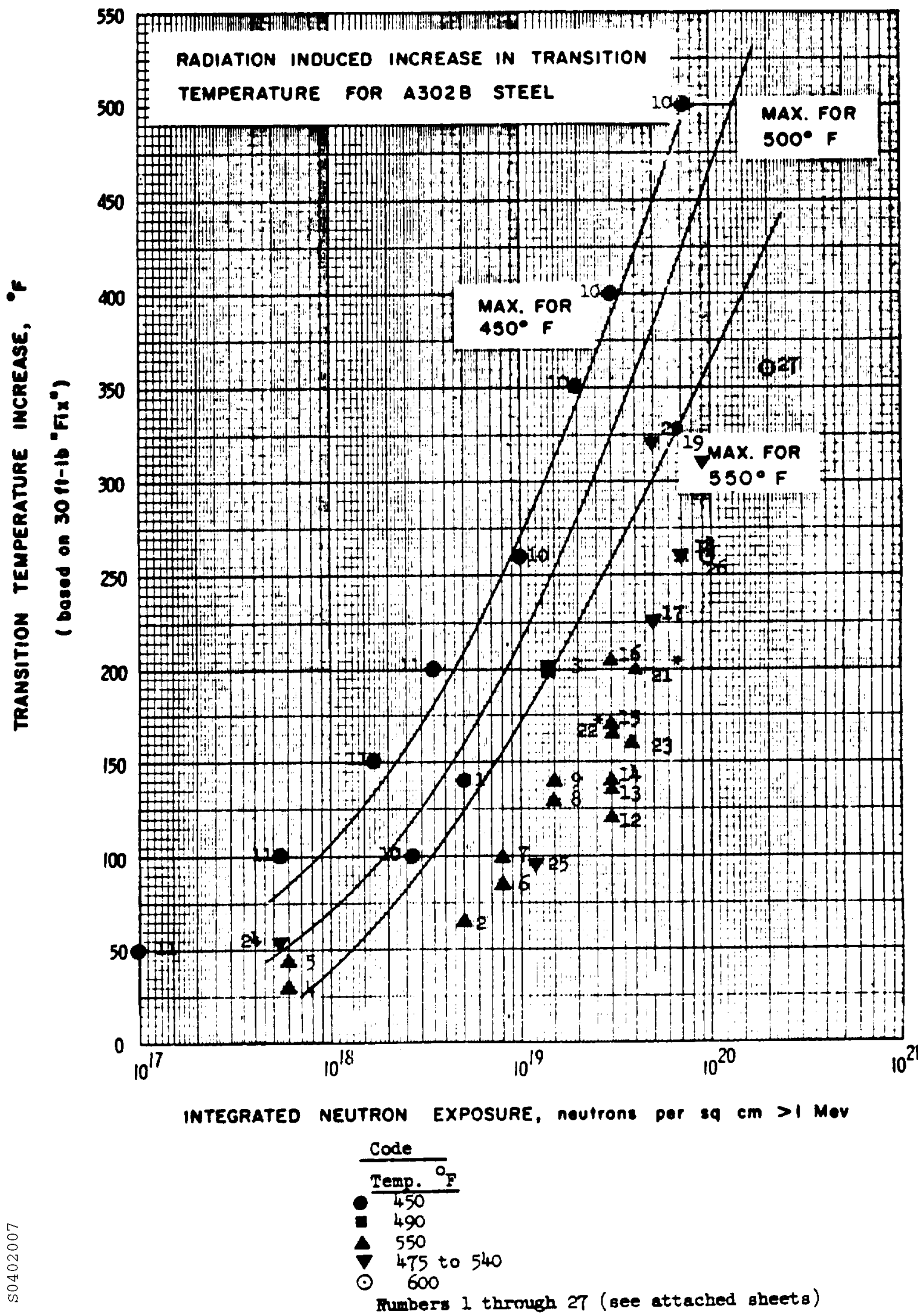


Figure 4.2-10
CONTAINMENT AIR PARTICULATE MONITOR RESPONSE TIME AS A FUNCTION OF PERCENTAGE OF FAILED FUEL AND RATE OF COOLANT LEAKAGE

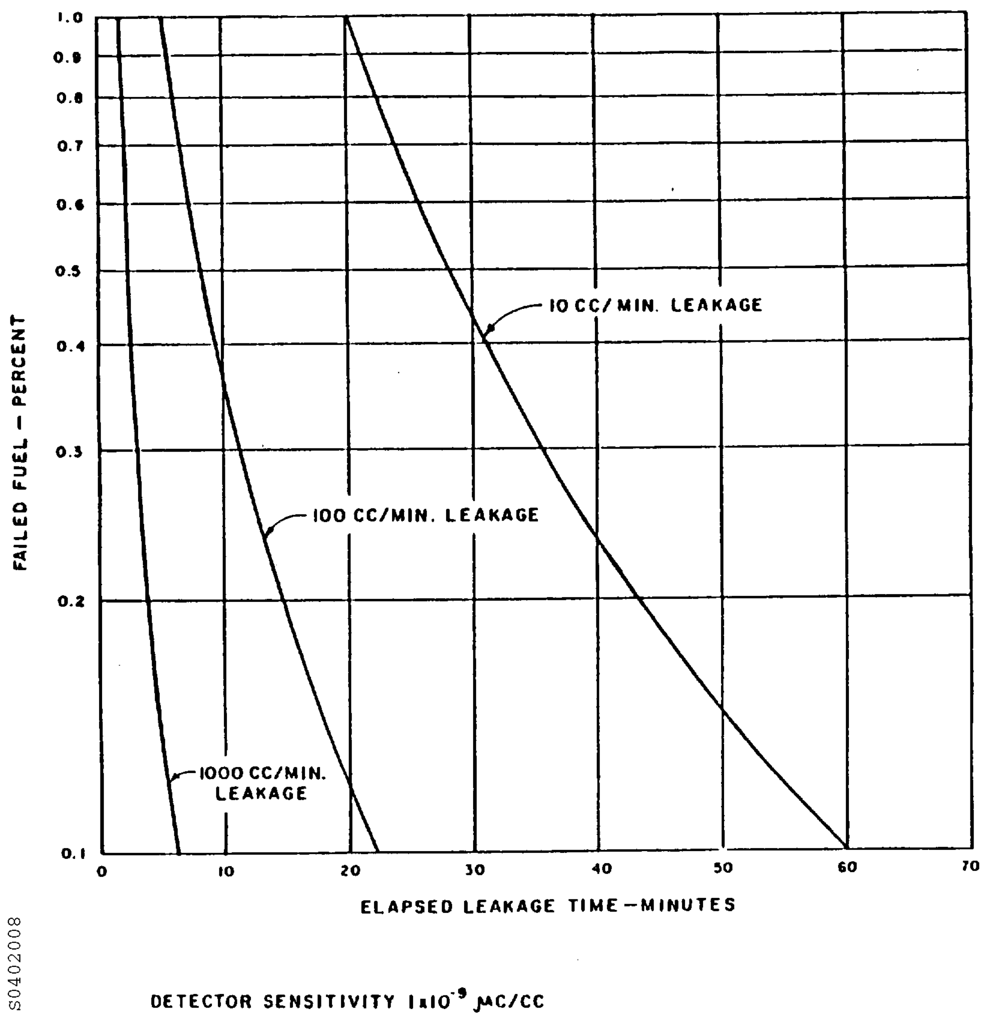
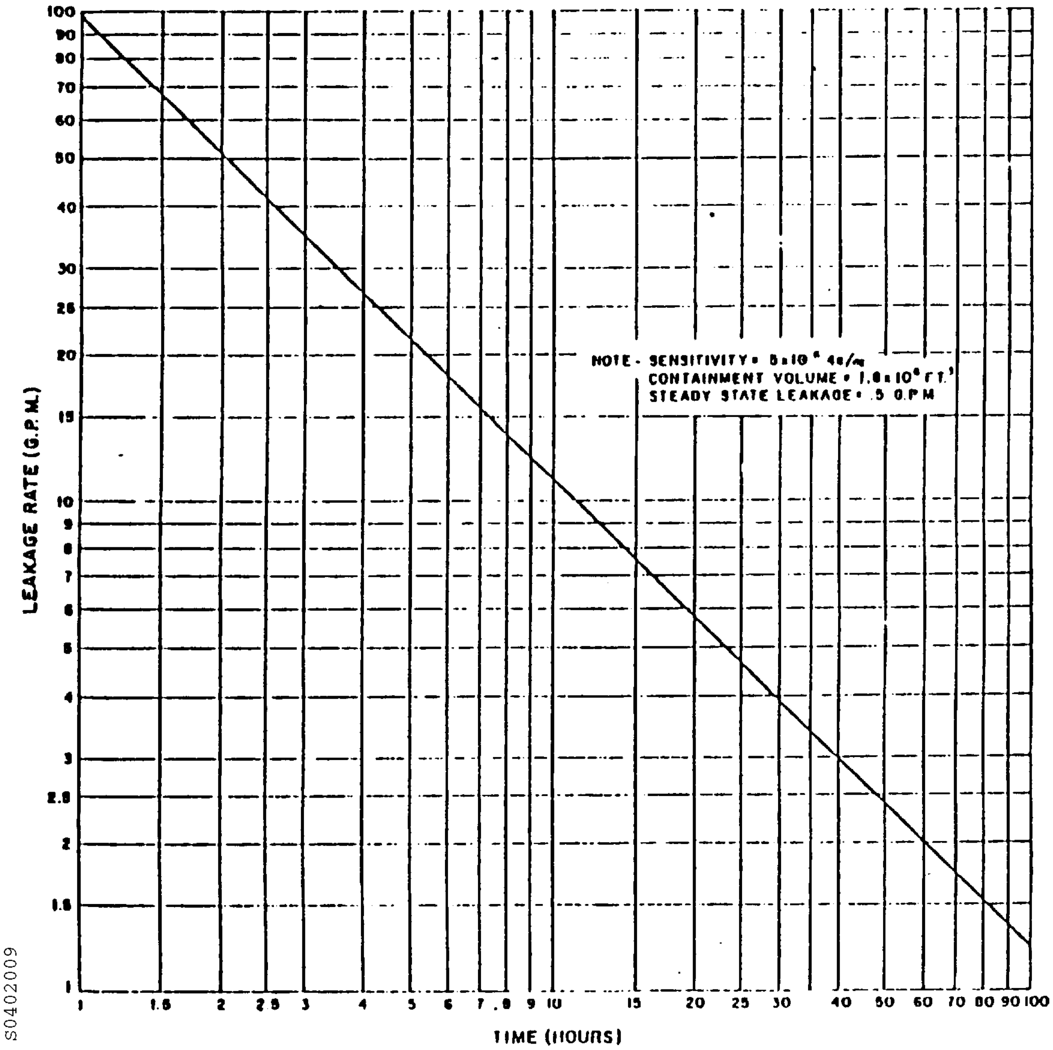


Figure 4.2-11
CONTAINMENT GAS MONITOR MINIMUM TIME TO DETECT LEAK



S0402009

Intentionally Blank

4.3 SYSTEM DESIGN EVALUATION

4.3.1 Safety Factors

The safety of the reactor vessel and all other reactor coolant system pressure-containing components and piping is dependent on several major factors, including design and stress analysis, material selection and fabrication, quality control, and operations controls.

4.3.1.1 Reactor Vessel

A stress evaluation of the reactor vessel was carried out in accordance with the rules of Section III of the ASME Code. The evaluation demonstrated that stress levels are within the limits of the code. Tables 4.3-1 and 4.3-2 presents a summary of the estimated stress evaluation.

Fatigue evaluations of the components having the highest cumulative usage factors including head, control rod housing, head flange, vessel flange, primary nozzles, closure studs, core support pad, bottom head to shell, and bottom instrumentation, were also performed. The evaluations show that the cumulative usage factors for these components are less than 1.0 as required by Section III of the ASME Boiler and Pressure Vessel Code, Nuclear Vessels.

The cycles specified for the fatigue analysis result from an evaluation of the expected unit operation, coupled with experience from nuclear power plants, such as Yankee-Rowe. These cycles include five heatup and cooldown cycles per year, a conservative selection and were based on the original 40-year operating license period.

The vessel design pressure is 2485 psig, while the normal operating pressure is 2235 psig. The resulting operating membrane stress is therefore amply below the code allowable membrane stress to account for operating pressure transients.

To preclude the possibility of brittle failure, the combined pressure and thermal stresses in the reactor vessel are limited in accordance with the requirements of ASME Section XI Appendix G, which is cited in 10 CFR 50 Appendix G (Reference 1).

These stress limits are maintained by operating procedures that rely upon administrative pressure and temperature control during heatup and cooldown.

The shift in Reference Temperature for the Nil Ductility Transition (RT_{NDT}) is established periodically during operation by testing of vessel material samples which are irradiated cumulatively by securing them near the inside wall of the vessel in the core area. To compensate for any increase in the RT_{NDT} caused by irradiation, the limits given in the station operating manual on the pressure-temperature relationship are periodically changed to stay within the stress limits, which are stated above during heatup and cooldown. Refer to Section 4.1.7.

The vessel closure contains 58 6-inch studs. The stud material is SA-540 with a minimum yield strength of 104,400 psi at design temperature. The membrane stress in the studs at the steady-state operational condition is approximately 37,500 psi.

The normal operating temperature always exceeds even the highest anticipated DTT during the life of the station. Thus, the emphasis of conservative operation is placed on heatup and cooldown because long-term irradiation of the vessel raises the DTT and thereby limits the heatup or cooldown rates. The conservatism in setting up the temperature-pressure relationship limits stated above consists of:

1. Use of a stress concentration factor of four on assumed flaws in calculating the stresses.
2. Use of nominal yield of material instead of actual yield.
3. Neglecting the increase in yield strength resulting from radiation effects.

As part of the initial station operator training program, Westinghouse instructed supervisory and operating personnel in reactor vessel design, fabrication, and testing, as well as present and future precautions necessary for pressure testing and operating modes. The need for record-keeping was stressed. Such records are helpful in determining the number of operating hours at various power levels and temperatures. These data are used to determine the effects of irradiation on the materials in the core region. These instructions are incorporated in the operating manuals.

The allowable stress criteria for the reactor internals indicate that for the bending state of stress, an outer fiber strain of 40% of ultimate strain is specified. This limit is equal to the average absolute strain (20% of the ultimate strain) in the cross section. If the loading is pure bending, this will give a maximum outer fiber strain of 40%. The 20% average fiber strain is 8% of the actual strain at ultimate.

The geometric shape factor does not enter directly into these strain considerations. The normal geometric shape factor that is used is 1.27 for circular piping.

The following structural elements of the reactor pressure vessel are analyzed in detail (refer to Figures 4.3-1 and 4.3-2):

A. Main closure, including adjacent shells, flange rings, and studs.

B. Inlet and outlet nozzles.

C. Core support pads and adjacent shell.

D. Transition in the cylindrical shell and transition from the cylindrical shell to bottom head.

E. Control rod drive housings.

F. Instrumentation tubes.

A description of the method of analysis for each of the above items is given below:

A. Main Closure

An analytical model is used in which the cylindrical and the spherical shell courses are treated according to the thin-shell theory.

The hubs, if present, are treated as either stiff rings or as a general shell. The flanges are treated as stiff rings or, when possible, partly as a shell, and the studs are treated as cantilever beams.

The deformations at the junctures between the elements are expressed in terms of thermal load, mechanical load, and redundant forces. Then the interaction analysis is performed by solving the set of equations, which is obtained by application of the equilibrium and compatibility conditions.

Once the redundant forces and displacements are known, the stresses are easily calculated.

This is done for all possible load combinations, so a complete analysis is made in which the stresses are compared with the stress and fatigue limits given by the ASME Boiler and Pressure Vessel Code, Section III.

The thermal analysis is performed by calculation of a three-dimensional model using a finite difference technique.

B. Inlet and Outlet Nozzles Including Adjacent Shell

These items are analyzed by methods depending on the loads considered.

The stresses caused by internal pressure and non-uniform temperature distribution are found by means of finite element technique.

The stresses in the shell due to external forces induced by its own weight, earthquake, pipe break, etc., are calculated using the revised Bijlaard curves (Reference 2), while the stresses in the nozzle are found by treating the nozzles as cantilever beams.

The non-uniform temperature distribution due to the main thermal transient is calculated with a finite difference technique.

Finally, the stresses due to all possible load combinations are calculated for various cross sections, and compared with the applicable stress and fatigue limits.

C. Core Support Pads and Adjacent Shell

The stresses in the pads due to mechanical loads are found by treating the pads as clamped cantilever beams, while the stresses in the shell are calculated with the Bijlaard curves (Reference 2).

The stresses due to steady-state temperature fluctuations are determined by means of the skin stress method.

At the end, the stresses due to the various specified load combinations are compared with the applicable stress and fatigue limits.

D. Vessel Wall Transition

The stresses in the vessel wall transition are found by treating the wall according to the thin-shell theory, with respect to the pressure stresses as well as to the temperature-induced stresses.

It is assumed that the worst temperature distribution occurs at the end of the heatup. This temperature is hand calculated. Stresses due to fast thermal transients are calculated with the formulas for skin effect stresses. The total stresses due to the possible load combinations are compared with the applicable stress and fatigue limits.

E. Control Rod Drive Housing

The following paragraphs apply to Surry Unit 1 only.

The analysis of the control rod drive housing and the adjacent shell is performed in two steps.

The first step is to calculate the temperature distribution due to thermal transients using the finite difference method. The boundary condition in the thermal analysis is that in all cases the shrink fit remains, i.e., there is always conduction between the housing and the shell.

The second step is to calculate the stresses due to internal pressure, shrink fit, and temperature distribution for all load conditions. The effects due to a difference in coefficient of thermal expansion are also considered. The relative radial displacement of both housing and hole in the vessel wall is checked for all conditions to be sure that the assumed boundary condition holds. After combining the calculated stresses, the results are compared with the applicable stress and fatigue limits.

The following paragraphs apply to Surry Unit 2 only.

The analysis of the control rod drive housing and adjacent shell is performed in two steps.

The first step is to calculate the applicable thermal boundary conditions based on the design transient conditions. This is done using classical heat transfer methods. The thermal boundary conditions are applied to a finite element analysis to determine temperatures in the structure. Conduction between the adjacent shell and housing is applied in the shrink-fit region.

The second step is to calculate stresses in the housing and adjacent shell due to internal pressure and temperature distribution for all load conditions. This is also done using a finite element analysis. The effects due to a difference in coefficient of thermal expansion are considered. Shrink fit is considered in this evaluation. After combining the calculated stresses, the results are compared with the applicable stress and fatigue limits.

F. Flux Monitor Housing

The analysis of the flux monitor housing is performed in the same way as for item 5. The only difference is that there exists a clearance fit between housing and shell that will remain at all load conditions.

4.3.1.2 **Steam Generators**

A stress evaluation of the steam generators was performed in accordance with Section III of the ASME Boiler and Pressure Vessel Code. Based on the stress evaluation, the critical steam generator components meet the required stress and fatigue limits of ASME Section III (1974 Edition through Winter 1976 Addendum).

The steam generator is designed to withstand a maximum primary-to-secondary pressure differential of 2485 psig coincident with a maximum temperature of 650°F. This faulted condition is postulated to result from a steam-line-break accident.

Faulted conditions are defined in paragraph N-412(t)5 of Section III of the ASME Code. Stress limitations, based on the lower bound theorem of limit analysis for this condition, are stated in paragraph N-417.11(a & b).

The steam generator is also designed for a loss-of-coolant accident (LOCA) wherein a secondary-to-primary pressure differential of 1100 psid at 600°F can occur. This faulted condition is postulated to result from a reactor-coolant-pipe-break accident[1]. The above code reference is applicable.

The 1100-psid pressure differential resulting from the LOCA is less than the normal operating pressure differential of 1465 psid (2250 psia primary minus approximately 785 psia secondary). Therefore, this accident condition does not result in any stresses in the tubesheet in excess of those determined for the normal operating condition.

No significant corrosion of the Inconel tubing is expected during the lifetime of the station. The corrosion rate reported in Reference 3 shows worst-case rates 15.9 mg/dm^2 in the 2000-hour test under steam generator operating conditions. Conversion of this rate to a 60-year unit life gives a corrosion loss of less than 2.3×10^{-3} inch, which is insignificant compared to the nominal tube wall thickness of 0.050 inch. It has been shown that, to increase the 60-year unit life to 80 years, it can be concluded that the calculated uprate tube wear at 60 years of operation (<2 mils) will not result in unacceptably large rates of tube wear if extended to 80 years of operation.

Collapse tests of 7/8-.050 wall straight tubes at room temperature indicate that actual tube strengths are significantly higher than specification, and a collapse pressure of 6000 psi is recorded for the straight tube. The ASME Code charts indicate a collapse pressure of 2740 psi for this tube. The difference is attributed to the fact that the yield strength of the tube tested was 44,000 psi, and the code charts are based on a yield strength of approximately 29,000 psi at room temperature.

---

1. As discussed in Section 15.6.2, "leak-before-break" analyses have demonstrated that the probability of rupture of the primary reactor coolant loop piping and select branch reactor coolant piping sections is extremely small, and it is no longer necessary to consider the dynamic effects of such an accident for the 80 year period of extended plant operations. However, this does not alter the primary loop LOCA as the design basis for the steam generators.

Consideration is given to the superimposed effects of secondary-side pressure loss and the design-basis earthquake loading. The fluid dynamic forces on the internal components affecting the primary-secondary boundary (tubes) is considered as well. For this condition the criterion is that no rupture of primary-to-secondary boundary (tubes and tubesheet) occurs.

The fluid dynamic forces on the internals under secondary-steam-break accident conditions indicate, in the most severe case, that the tubes are adequate to constrain the motion of the baffle plates. There is some plastic deformation, but boundary integrity is maintained.

4.3.1.3 **Steam Generator Tube Vibration Considerations**

In the design of power system steam generators, it has been recognized that an inadequately supported tube can give rise to the serious consequences of flow-induced vibration, which may lead to primary/secondary tube leakage. Historically, it has been noted that many tube vibratory failures have been due to local design configuration weaknesses such as impingement of fluid on the bundle through nozzles without protective baffle plates.

Flow induced vibration at the tubesheet caused by turbulence, fluidelastic excitation, and vortex shedding has been evaluated. These analyses have revealed that at the maximum alternating bending stress in the tube, the code allowable number of cycles is infinite and the fatigue factor is zero.

For the tube supports, the wear coefficient of the type 405 stainless steel supports is low enough to effectively maintain initial tube clearances. Although tests and calculations show that the tube support conditions will not change noticeably during the vessel life, analyses have been performed assuming loss of support at various elevations, and the alternating tube bending stress did not exceed allowed values.

The propensity for a steam generator tube rupture due to flow-induced vibration was specifically evaluated for the steam generators at the uprated conditions. The use of stainless steel essentially eliminates the potential for tube denting in the support plates. Since tube denting is a prerequisite for flow-induced vibration that can lead to tube failure, the likelihood for this type of tube degradation is not significant.

4.3.1.4 **Piping Quality Assurance**

Quality control techniques used in the fabrication of the reactor coolant system are equivalent to those used in manufacture of the reactor vessel which conforms to Section III of the ASME Code.

The Nuclear Piping Code B31.7 is derived from ASME Section III criteria. Thus, the quality assurance requirements added by Westinghouse to USAS B31.1.0-1955 procured reactor coolant piping ensure that the quality level of a Westinghouse plant is comparable to that of Nuclear Piping Code USAS B31.7 itemized below:

1. The material specifications are ASTM specifications approved for nuclear use in the various code cases.
2. The reactor system materials are non-destructively examined to levels required of Class A vessels.
3. Welding procedures and welders must be qualified to the requirements of Section IX of the ASME Code. The same requirement prevails in USAS B31.7.
4. All main primary coolant butt welds, 29, 31, and 27.5-inch o.d. are examined to the same standards required in USAS B31.7. All other butt welds are examined as required by USAS B31.1.
5. All nozzle welds must be radiographically examined when the branch weld is in excess of 2-inch pipe size.
6. All nozzle, girth, and longitudinal welds must be liquid penetrant examined. This requirement is equivalent to USAS B31.7.
7. Hydrostatic testing is performed in completed systems. This requirement is equivalent to USAS B31.7.

Field erection and welding procedures are governed by Westinghouse specifications, which, upon implementation, ensure that the field fabrication results in the same quality as that resulting from the shop fabrication of the same piping. In these specifications for shop fabrication and field erection are references to portions of the ASME Code.

4.3.2 Reliance on Interconnected Systems

The principal heat removal systems that are interconnected with the reactor coolant system are the steam and power conversion, safety injection, and residual heat removal systems. The reactor coolant system is dependent upon the steam generators, the main steam system (Section 10.3.1), and the condensate and feedwater systems (Section 10.3.5) for stored and residual heat removal from normal operating conditions down to a reactor coolant temperature of approximately 350°F. The layout of the reactor coolant system ensures the natural circulation capability to permit unit cooldown following a loss of power to all reactor coolant pumps. The auxiliary steam generator feedwater pumps (Section 10.3.5) supply water to the steam generators in the event that the main feedwater pumps are inoperative. The safety injection system is described in Section 6.2. The residual heat removal system is described in Section 9.3.

4.3.3 System Integrity

A complete stress analysis that reflects consideration of all design loadings detailed in the design specification is prepared by the manufacturer to ensure compliance with the stress limits on Section III of the ASME Boiler and Pressure Vessel Code for the reactor vessel, steam generator, reactor coolant pump casing, and pressurizer. A similar analysis of the piping is prepared by a qualified piping analyst to show compliance with the stress limits of the applicable USA Standard.

As part of the design control on materials, Charpy V-notch toughness test curves are run on all ferritic material used in fabricating pressure parts of the reactor vessel, steam generator, and pressurizer to provide assurance for hydrotesting and operation in the ductile region at all times. In addition, drop-weight tests are performed on the reactor vessel plate material.

As an assurance of system integrity, all pressure-containing components in the system were hydrotested at 3107 psig prior to initial operation.

4.3.3.1 **Reactor Coolant Pump Flywheel Integrity**

Precautionary measures, taken to preclude missile formation from reactor coolant pump components, ensure that the pumps will not produce missiles under any anticipated accident condition.

The reactor coolant pumps run at 1189 rpm, and the controlled leakage pump assembly is capable of operation without mechanical damage with overspeeds up to and including 125% of nominal speed.

Each component of the pumps has been analyzed for missile generation. Any motor rotor fragments would be contained by the heavy stator. The same conclusion applies to the impeller, because the small fragments that might be ejected would be contained by the pump casing.

The reactor coolant pump flywheel dimensions are shown in Figure 4.3-3. As for the pump motors, the most adverse operating condition of the flywheels is considered to be the loss-of-load situation. The following conservative design-operation conditions preclude missile production by the pump flywheels. The flywheels are fabricated from rolled, vacuum-degassed, ASTM A-533 steel plates. Flywheel blanks are flame-cut from the plate, with allowance for exclusion of flame-affected metal. A minimum of three Charpy tests are made from each plate parallel and normal to the rolling direction, to determine that each blank satisfies design requirements. An NDTT less than +10°F is specified. The finished flywheels are subjected to 100% volumetric ultrasonic inspection. The finished machined bores are also subjected to magnetic particle or liquid penetrant examination. These design-fabrication techniques result in flywheels with primary stress at operating speed (shown in Figure 4.3-4) less than 50% of the minimum specified material yield strength at room temperature (100° to 150°F). A detailed evaluation has been performed to determine the critical speed for the reactor coolant pump flywheel from the standpoint of fracture and subsequent missile production. Ductile failure and brittle fracture of the flywheel were considered individually. Limiting speeds were established for each. The ductile failure limit of 3485 rpm (290% overspeed) is governing for crack sizes less than 1.15 inches, and the brittle fracture limit becomes governing for larger crack sizes. Because this crack size is very large in comparison to that which is detectable under current procedures, it is conservatively concluded that 3485 rpm is the limiting speed for the design (Reference 4).

An ultrasonic inspection capable of detecting at least 0.5-inch-deep cracks from the ends of the flywheel, and a dye penetrant or magnetic particle test of the bore, both at the end of 10 years, were more than adequate as part of a unit surveillance program. These inspections were applicable to the first two inspection intervals.

The design specifications for the reactor coolant pumps include as a design condition the stresses generated by a design-basis earthquake ground acceleration of 0.15g. The pump would continue to run unaffected by such conditions. In no case does any bearing stress in the pump exceed or even approach a value that the bearing could not carry.

In order to preclude undetected flywheel deterioration during plant life, even though such deterioration is not expected, the flywheel will be inspected once every twenty years (Reference 14). The inspection shall be a qualified inplace UT examination over the volume from the inner bore of the flywheel to the circle of one-half the outer radius or a surface examination (MT and/or PT) of exposed surfaces defined by the volume of the disassembled flywheels.

Following a hypothetical bearing seizure, the flywheel is not expected to twist off. Therefore, the reactor coolant pumps are not considered sources of missiles and the engineered safeguards are not in jeopardy.

4.3.3.2 **Pressurized Thermal Shock**

The Pressurized Thermal Shock (PTS) Rule was approved by the U. S. Nuclear Regulatory Commissioners on June 20, 1985, and appeared in the Federal Register on July 23, 1985. The Code of Federal Regulations (10 CFR 50.61) contains the applicable requirements and screening criteria.

The Rule outlines regulations to address the potential for PTS events on reactor vessels in nuclear power plants. PTS events have been shown from operating experience to be transients that result in a period of severe cooldown in the primary system coincident with a high or increasing primary system pressure. The PTS concern arises if one of these transients acts on the beltline or extended beltline regions of a reactor vessel where a reduced fracture resistance exists because of neutron irradiation. Such an event may produce the propagation of flaws postulated to exist near the inner wall surface, thereby potentially affecting the integrity of the vessel.

As part of the calculations which support Surry 1 and 2 subsequent license renewal limits (Reference 20) RT_{PTS} values were generated for each Surry 1 and 2 beltline or extended beltline material using the prescribed PTS Rule Methodology. These calculations utilized initial (unirradiated) RT_{NDT} and end of 80-year license fluence. Compliance with 10 CFR 50.61 for the original 40-year license period was transmitted by References 6, 12, and 13. Reference 16 provided the RT_{PTS} values to the NRC, applicable to the 60-year operating licenses. The results for the 80-year RT_{PTS} are presented in Tables 4.3-3 and 4.3-4 for Units 1 and 2, respectively. As these tables demonstrate, all RT_{PTS} values remain below the PTS screening criteria throughout the currently licensed life of the Surry Units 1 and 2. It has been determined that all Surry Units 1 and 2 reactor vessel beltline and extended beltline materials meet the 10 CFR 50.61 PTS screening criteria for operation through the end of the 80-year license period.

4.3.4 Overpressure Protection

The reactor coolant system is protected against overpressure by code safety valves and power-operated relief valves located on the top of the pressurizer. The safety valves on the pressurizer are sized to prevent system pressure from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code. The capacity of the pressurizer code safety valves and power-operated relief valves is determined from considerations of the reactor protection system, and accident or transient conditions that may cause overpressure.

Mass input and heat input pressure transients were assumed, and calculations were performed to determine the low pressure overpressure protection setpoint for the power-operated relief valves (References 9 & 10).

The setpoint was chosen to ensure that 110% of the ASME Section XI Appendix G isothermal limit curve will not be exceeded during a limiting pressure transient (References 9, 10 & 11). Sufficient safety margin is provided by this setpoint, since the transient analysis shows that only one power-operated relief valve, set to open at 390 psig, is required to prevent exceeding 110% the Appendix G isothermal limit. The power-operated relief valves are set to operate as discussed above whenever the reactor coolant system is less than 350°F and the reactor head is bolted.

For subsequent license renewal (SLR), Reference 21 extended the cumulative core burnup applicability limit for the pressure/temperature limits and low temperature overpressure protection system (LTOPS) enabling temperature to 68 EFPY, and included consideration of the Measurement Uncertainty Recapture (MUR) uprate.

Vepco has submitted plant specific data to the NRC for safety and relief valve testing and for the power-operated relief valve block valve testing required by NUREG-0737, Item II.D.I. This information is provided in References 7 and 8, respectively.

In Reference 7 it was concluded that the Surry Units 1 and 2 safety and relief valves, piping arrangement, and fluid inlet conditions were bounded by the valve and test parameters of the EPRI safety and relief valve test program and that the EPRI tests confirmed the ability of the safety and relief valves to open and close under the expected operating fluid conditions. In Reference 8 it was concluded that the block valve tested by EPRI was similar in design to the Surry block valves and that the valve successfully completed the evaluation and test program, fully opening and closing on demand.

4.3.4.1 **Operational Conditions**

The operational conditions requiring overpressure protection are controlled by administrative procedures as follows:

1. While water-solid, only one charging pump is permitted to be operational.
2. The safety injection accumulators must be isolated so that they do not discharge into the reactor coolant system while water-solid.
3. The safety injection logic must be blocked while water-solid.
4. The temperature of the reactor coolant system must not be more than 50°F cooler than the bulk water in the steam generators before starting the first reactor coolant pump.

4.3.4.2 **Air Supply**

A backup air supply is provided to ensure power-operated relief valve operability in the event of a loss of the primary air supply and/or a loss of offsite power. The sizing of the redundant air supply considered both power-operated relief valve response times with the above setpoints, and assumed that operator action does not occur for 10 minutes. Annunciators are provided to alert operators of low air pressure supply. Four high-pressure air bottles are provided for each valve. Two bottles are normally aligned to the manifold, the other two are initially fully charged and used as installed spare bottle capacity. The intent is to reduce the time required to reestablish bottle pressure when a low pressure alarm occurs. Alternatively, the spare bottles may be valved in to increase the air supply available during certain modes of plant operation.

The capacity of available bottles is a function of valve stroke time and air regulator setpoint. Valve stroke time is dependent upon the valve condition and air regulator setpoint. The air bottle volumes are each 1.74 ft^3 and contain a nominal pressure of 2200 psig. The minimum pressure required to fully stroke the valve is 85 psig without assistance from Reactor Coolant System pressure. The minimum pressures required at the power operated relief valve (PORV) diaphragm to full stroke the valve at Reactor Coolant pressure of 365 psig and 2335 psig are 79 psig and 37 psig, respectively. This includes the effects of RCS pressure assistance on the required minimum backup air pressure. The following formula is used with current plant parameters and setpoints to determine required bottle capacity:

$$P_{INITIAL} = P_{FINAL} + [P_{CYCLE} * V_{CYCLE} *N]/V_{ACCUM}$$

where:

$P_{INITIAL}$	=	Initial pressure in the accumulator, psig
P_{FINAL}	=	Final pressure in the accumulator, 100 psig
P_{CYCLE}	=	Air regulator setpoint, psia
V_{CYCLE}	=	Volume of air required to complete a PORV cycle, 0.126 ft^3
N	=	Number of PORV cycles as analyzed for power operations or LTOPS operation

V_{ACCUM} = Total volume of the air accumulator, (total volume of bottles aligned to system, 1.74 ft^3 per bottle)

The containment instrument air system header to the power-operated relief valves contains two solenoid valves in series and a backup high-pressure air supply in the line to each relief valve. Two reactor coolant system transmitters are used to provide high-pressure alarms and to control the valves. Two key-lock switches are installed in the main control board (vertical section) to permit administrative control of the system at the appropriate point during cooldown or heatup.

4.3.5 System Accident Potential

The potential of the reactor coolant system as a cause of accidents was evaluated by investigating the consequences of certain credible types of component and control failures, as discussed in Sections 14.2 and 14.3. Reactor coolant pipe rupture is evaluated in Section 14.5.

As evaluated in Section 14.2, no credible component or control failure results in a DNBR less than the design DNBR limit (Section 3.2.3). Sections 14.3 and 14.5 show that for breach of the reactor coolant system boundary resulting from a steam generator tube rupture, a rod-ejection accident, or a pipe break up to and including the double-ended rupture of a reactor coolant pipe, the consequences in terms of activity releases are within the guidelines of 10 CFR 50.67 or RG 1.183, as applicable.

4.3.6 Redundancy

Each loop of the reactor coolant system contains a steam generator and a reactor coolant pump. The normal power supply to the reactor coolant pumps is from electrically separate buses, as shown in Figure 8.3-1.

4.3 REFERENCES

1. 10 CFR 50 Appendix G, *Fracture Toughness Requirements.*
2. K. R. Wichman et al, "Local Stresses in Spherical and Cylindrical Shells Due to External Loadings," *Welding Research Council Bulletin*, No. 107, August 1965.
3. W. E. Berry and F. W. Fink, *The Corrosion of Inconel in High Temperature Water*, Battelle Memorial Institute, April 1958.
4. R. Salvatori, *Topical Report, Reactor Coolant Pump Integrity in a LOCA,* WCAP-8163, September 1973.
5. Intentionally left blank.
6. Letter from L. H. Hartz, (Virginia Power) to USNRC, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Supplement to Response to NRC Request for Additional Information (RAI) on Generic Letter 92-01, Revision 1, Supplement 1,* Serial No. 99-034, dated February 24, 1999.

7. Letter from R. H. Leasburg, Vepco, to H. R. Denton, NRC, Subject: Response to NUREG-0737 Post-TMI Requirement - Item II.D.1, Relief, Safety, Block Valve Test and Discharge Piping Analysis Requirements, Plant Specific Report, dated July 1, 1982 (Serial No. 392).

8. Letter from R. H. Leasburg, Vepco to H. R. Denton, NRC, Subject: Response to NUREG-0737 Post-TMI Requirement - Item II.D.1, Relief, Safety, Block Valve Test and Discharge Piping Analysis Requirements, Block Valve Reports, dated September 1, 1982 (Serial No. 514).

9. Letter from James P. O'Hanlon, (Virginia Power) to USNRC, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Request for Exemption-ASME Code Case N-514, Proposed Technical Specification Change, Revised Pressure/Temperature Limits and LTOPS Setpoint,* Serial No. 95-197, dated June 8, 1995.

10. Letter from B. C. Buckley (USNRC) to J. P. O'Hanlon, *Surry Units 1 and 2- Issuance of Amendments Re: Surry, Units 1 and 2 Reactor Vessel Heatup and Cooldown Curves (TAC Nos. M92537 and M92538),* Serial No. 96-020, dated December 28, 1995.

11. Letter from David B. Matthews (USNRC) to J. P. O'Hanlon, *Exemption from Requirements of 10 CFR 50.60, Acceptance Criteria for Fracture Prevention for Light-Water Nuclear Power Reactors for Normal Operation, Surry Power Station, Units 1 and 2 (TAC Nos. M92537 and M92538),* Serial No. 95-572, dated October 31, 1995.

12. Letter from L. N. Hartz to USNRC, *Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Surry Power Station Units 1 and 2, Evaluation of Reactor Vessel Materials Surveillance Data,* dated November 19, 1999.

13. Letter from L. N. Hartz to USNRC, *Virginia Electric and Power Company, Surry Power Station Unit 2, Evaluation of Capsule Y Data,* dated March 27, 2003.

14. Letter from S. R. Monarque (USNRC) to D. A. Christian, *Surry Power Station Units 1 & 2 - Issuance of Amendments to Extend the Inspection Interval for RCP Flywheels,* (TAC Nos. MC4215 & MC4216), Serial No. 05-413, dated June 21, 2005.

15. Letter from E. S. Grecheck to USNRC, *Virginia Electric and Power Company Surry Power Station Units 1 and 2 Update to NRC Reactor Vessel Integrity Database and Exemption Request for Alternate Material Properties Basis Per 10 CFR 50.60(b),* dated June 13, 2006.

16. Letter from L. N. Hartz (Dominion) to NRC, *Virginia Electric and Power Company (Dominion), Surry Power Station Units 1 and 2, License Amendment Request, Measurement Uncertainty Recapture Power Uprate*, Serial No. 09-223, January 27, 2010.

17. Intentionally left blank.

18. Letter from J. A. Price to USNRC, *Surry Power Station Units 1 and 2, License Amendment Request Revised Cumulative Core Burnup Applicability Limit for Heatup and Cooldown Curves, low Temperature Overpressure Protection System (LTOPS) Setpoint and LTOPS Enable Temperature,* dated May 6, 2010.

19. Letter from Karen Cotton to (USNRC) to D. A. Heacock, *Surry Power Station Unit Nos. 1 and 2, - Issuance of Amendments Regarding Reactor Vessel Heatup and Cooldown Curves*

For 48 effective Full-Power Years (TAC Nos. ME3920 and ME3921), Serial No. 11-322, dated May 31, 2011.

20. Westinghouse WCAP-18242-NP, Revision 2, *Surry Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal,* July 2018.

21. Westinghouse WCAP-18243-NP, Revision 2, *Surry Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation,* July 2018

.

Table 4.3-1
SUMMARY OF ESTIMATED PRIMARY-PLUS-SECONDARY STRESS INTENSITY FOR COMPONENTS OF THE REACTOR VESSEL - UNIT 1

Area	Total Stress Intensity, psi	Allowable Total Stress at Operating Temperature, psi
Control rod housing	69,800	69,900
Head flange	71,700	80,000
Vessel flange	69,500	80,000
Primary nozzles	53,757	80,100
Closure studs	85,600	109,740
Core support pad	40,800	69,900
Bottom head to shell	32,736	80,100
Bottom instrumentation	56,531	69,900

Table 4.3-2
SUMMARY OF ESTIMATED PRIMARY-PLUS-SECONDARY STRESS INTENSITY FOR COMPONENTS OF THE REACTOR VESSEL - UNIT 2

Area	Total Stress Intensity, psi	Allowable Total Stress at Operating Temperature, psi
Control rod housing	77,500	a
Head	47,900	80,100
Vessel flange	57,700	80,100
Primary nozzles	53,757	80,100
Closure studs	87,100	110,400
Core support pad	40,800	69,900
Bottom head to shell	32,736	80,100
Bottom instrumentation	56,531	69,900

a. The stresses in the control rod housing were determined to be acceptable using simplified elastic-plastic analysis in accordance with Paragraph NB-3228.5 of Section III of the ASME B&PV Code.

Table 4.3-3
RT_{PTS} VALUES FOR SURRY UNIT 1[a]

Vessel Material	Material Identification	68 EFPY RT_{PTS} Value (°F)	Screening Criteria (°F)
Nozzle Shell Forging	122V109VA1	144.1	270
Intermediate Shell Plate	C4326-1	150.2	270
Intermediate Shell Plate	C4326-2	151.6	270
Lower Shell Plate	C4415-1	157.2[b]	270
Lower Shell Plate	C4415-2	141.8[b]	270
Nozzle to Intermediate Shell Circumferential Weld	J726/25017	208.8	300
Intermediate to Lower Shell Circumferential Weld (ID 40%)	SA-1585/72445	229.8[b]	300
Intermediate to Lower Shell Circumferential Weld (OD 60%)	SA-1650/72445	229.8[b]	300
Intermediate Shell Longitudinal Welds L3 & L4	SA-1494/8T1554	195.4	270
Lower Shell Longitudinal Weld L1	SA-1494/8T1554	195.7	270
Lower Shell Longitudinal Weld L2	SA-1526/299L44	253.2[b]	270
Inlet Nozzle 1 to Upper Shell Weld	299L44	98.1[b]	270
Inlet Nozzle 2 to Upper Shell Weld	299L44	34.2[b]	270
Inlet Nozzle 3 to Upper Shell Weld	299L44	71.8[b]	270
Inlet Nozzle 1 to Upper Shell Weld	8T1762	80.7	270
Inlet Nozzle 2 to Upper Shell Weld	8T1762	34.5	270
Inlet Nozzle 3 to Upper Shell Weld	8T1762	56.0	270
Outlet Nozzle 1 to Upper Shell Weld	8T1762	34.5	270
Outlet Nozzle 2 to Upper Shell Weld	8T1762	34.5	270
Outlet Nozzle 3 to Upper Shell Weld	8T1762	72.0	270
Outlet Nozzle 1 to Upper Shell Weld	8T1554B	34.5	270
Outlet Nozzle 2 to Upper Shell Weld	8T1554B	34.5	270
Outlet Nozzle 3 to Upper Shell Weld	8T1554B	69.5	270
Inlet Nozzle 1	9-4787	65.0	270
Inlet Nozzle 2	9-5078	11,6	270
Inlet Nozzle 3	9-4819	-18.5	270
Outlet Nozzle 1	9-4825-1	-44.9	270
Outlet Nozzle 2	9-4762	-87.5	270
Outlet Nozzle 3	9-4788	-4.3	270

NOTES:

a. This table reflects results for a cumulative core burnup of 68 EFPY which corresponds to the estimated cumulative core burnup at the end of the 80-year license period
b. Projection performed with RG 1.99 Rev. 2, Position 2.1 and surveillance data from Surry Unit 1 reactor vessel surveillance program and/or sister plants

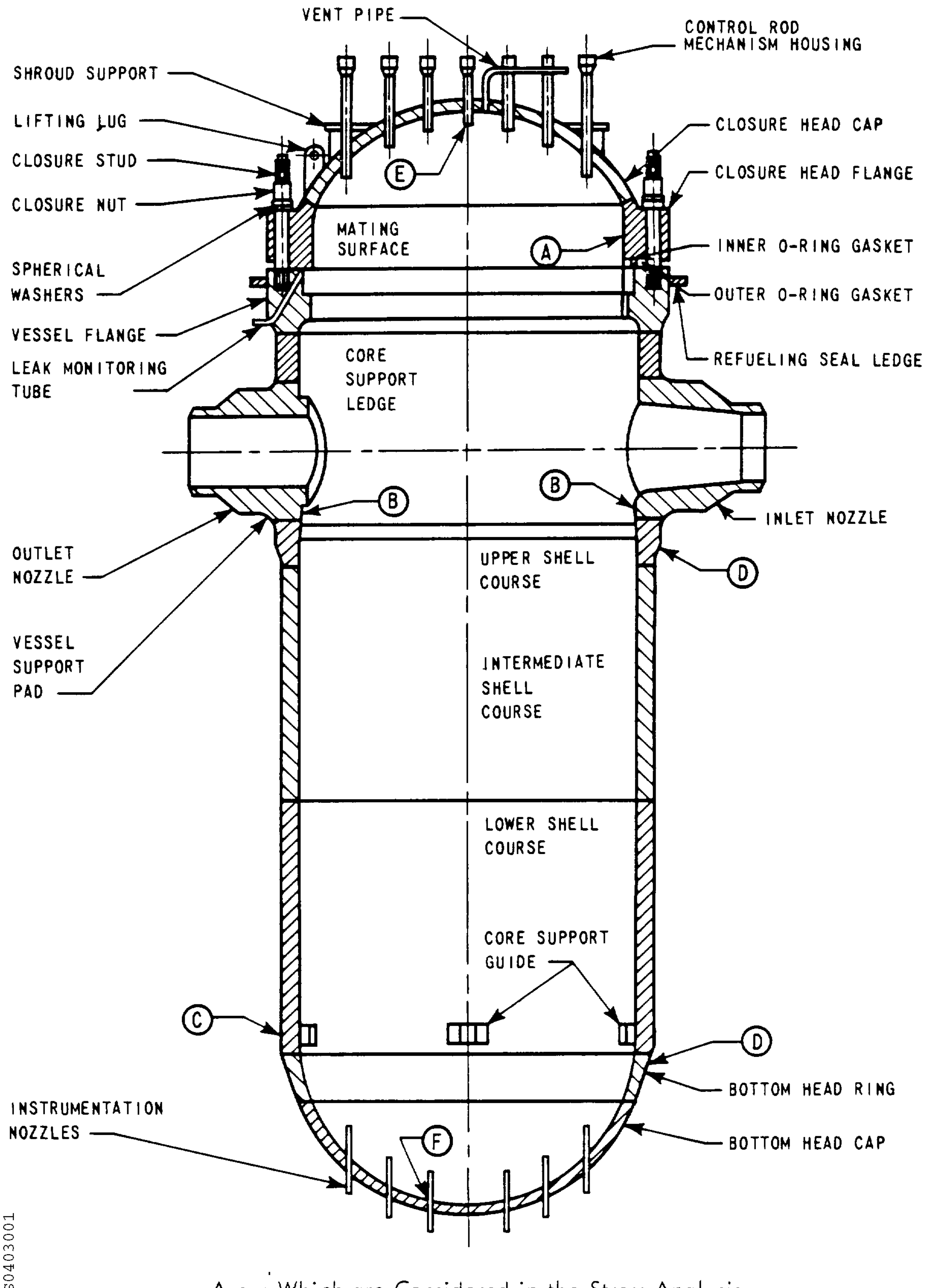
Table 4.3-4
RT_{PTS} VALUES FOR SURRY UNIT 2[a]

Vessel Material	Material Identification	68 EFPY RT_{PTS} Value (°F)	Screening Criteria
Nozzle Shell Forging	123V303VA1	136.7	270
Intermediate Shell Plate	C4331-2	170.8	270
Intermediate Shell Plate	C4339-2	152.9[b]	270
Lower Shell Plate	C4208-2	161.6	270
Lower Shell Plate	C4339-1	140.8[b]	270
Nozzle to Intermediate Shell Circumferential Weld	L737/4275	222.8	300
Intermediate to Lower Shell Circumferential Weld	R3008/0227	222.5[b]	300
Intermediate Shell Longitudinal Weld L4 (ID 50%)	WF-4/8T1762	196.8	270
Intermediate Shell Longitudinal Welds L3 (100%) and L4 (OD 50%)	SA-1585/72445	167.3[b]	270
Lower Shell Longitudinal Welds L2 (ID 63%) and L1 (100%)	WF-4/8T1762	197.2	270
Lower Shell Longitudinal Weld L2 (OD 37%)	WF-8/8T1762	197.2	270
Inlet Nozzle 1 to Upper Shell Weld	8T1762	84.4	270
Inlet Nozzle 2 to Upper Shell Weld	8T1762	34.5	270
Inlet Nozzle 3 to Upper Shell Weld	8T1762	55.7	270
Outlet Nozzle 1 to Upper Shell Weld	Rotterdam	30.0	270
Outlet Nozzle 2 to Upper Shell Weld	Rotterdam	30.0	270
Outlet Nozzle 3 to Upper Shell Weld	Rotterdam	138.0	270
Inlet Nozzle 1	9-5104	28.6	270
Inlet Nozzle 2	9-4815	4.5	270
Inlet Nozzle 3	9-5205	34.9	270
Outlet Nozzle 1	9-4825-2	-58.1	270
Outlet Nozzle 2	9-5086-1	-26.6	270
Outlet Nozzle 3	9-5086-2	15.3	270

NOTES:

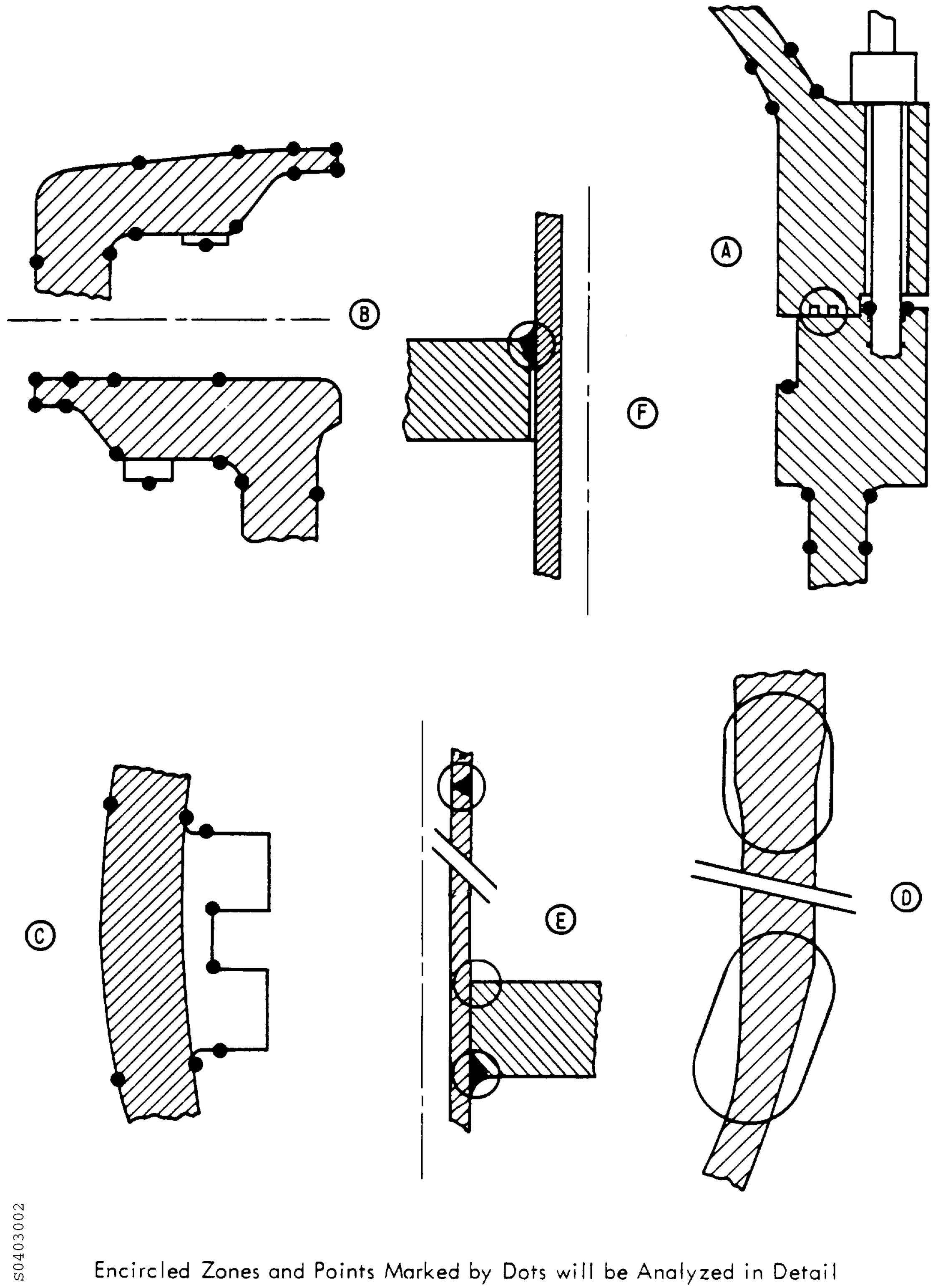
a. This table reflects results for a cumulative core burnup of 68 EFPY which corresponds to the estimated cumulative core burnup at the end of the 80-year license period
b. Projection performed with RG 1.99 Rev. 2, Position 2.1 and surveillance data from Surry Unit 2 reactor vessel surveillance program and/or sister plants

Figure 4.3-1
REACTOR VESSEL STRESS EVALUATION SHEET 1



Areas Which are Considered in the Stress Analysis

Figure 4.3-2
REACTOR VESSEL STRESS EVALUATION SHEET 2



Encircled Zones and Points Marked by Dots will be Analyzed in Detail

Figure 4.3-3
REACTOR COOLANT PUMP FLYWHEEL DIMENSIONS

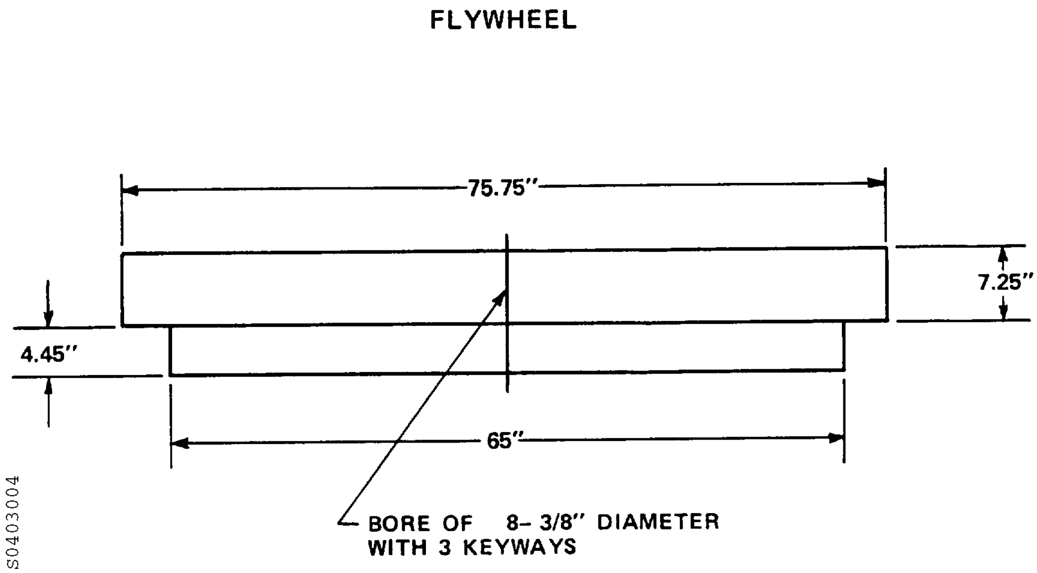
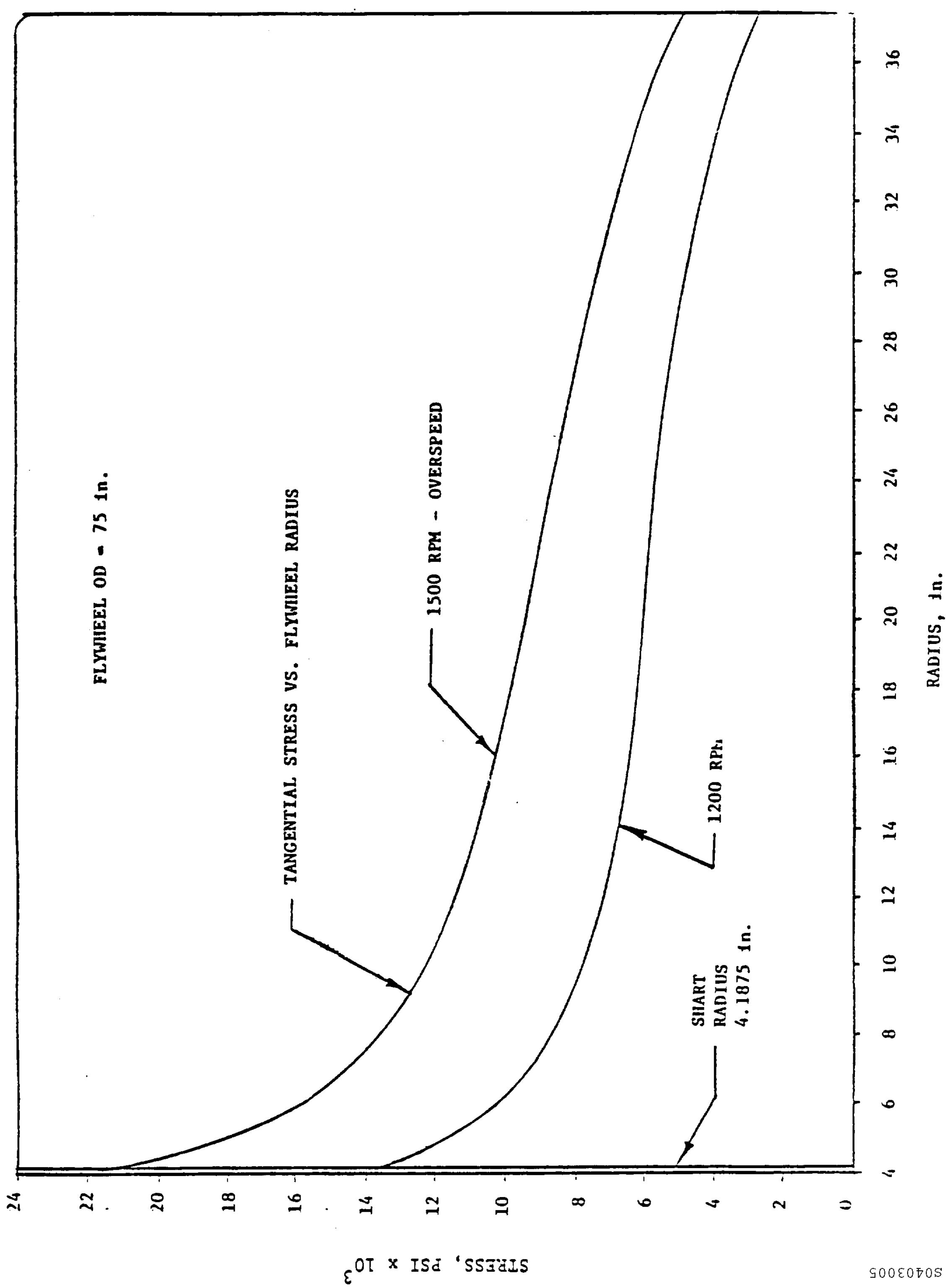


Figure 4.3-4
REACTOR COOLANT PUMP FLYWHEEL STRESSES



S0403005

Intentionally Blank

4.4 TESTS AND INSPECTIONS

4.4.1 Reactor Coolant System Inspection

4.4.1.1 Non-destructive Inspection of Materials and Components

Table 4.4-1 summarizes the quality assurance program for all reactor coolant system components. In this table all of the non-destructive tests and inspections required by Westinghouse specifications on reactor coolant system components and materials are specified for each component. All tests required by the applicable codes are included in this table. Westinghouse requirements, which were more stringent in some areas than those requirements specified in the applicable codes, are also included. The fabrication and quality control techniques used in the fabrication of the reactor coolant system were equivalent to those used for the reactor vessel.

Westinghouse required, as part of its reactor vessel specification, that certain special tests, which were not specified by the applicable codes, be performed. These tests are listed below:

1. Ultrasonic testing—Westinghouse required that a 100% volumetric ultrasonic test of reactor vessel plate for shear wave be performed in addition to code requirements. A 100% volumetric ultrasonic test is a severe requirement, but it ensures that the plate is of the highest quality.
2. Irradiation surveillance testing—The cumulative effects of neutron and gamma irradiation on the reactor vessel material, including weld metal and the heat-affected zones, are monitored as described in Section 4.1.7.

Table 4.4-1 summarizes the quality assurance program with regard to inspections performed on primary system components. In addition to the inspections shown in Table 4.4-1, there were those which the equipment supplier performed to confirm the adequacy of material he received, and those performed by the material manufacturer in producing the basic material. The inspections of reactor vessel, pressurizer, and steam generator were governed by ASME Code requirements. The inspection procedures and acceptance standards required on pipe materials and piping fabrication were governed by USAS B31.1 and Westinghouse requirements, and are equivalent to those performed on ASME-coded vessels.

Procedures for performing the examinations were consistent with those established in ASME Code Section III and were reviewed by qualified engineers. These procedures were developed to provide the highest assurance of quality material and fabrication. They considered not only the size of the flaws, but, of equal importance, how the material was fabricated, the orientation and type of possible flaws, and the areas of most severe service conditions. In addition, the accessible external surfaces of the primary reactor coolant system pressure-containing segments receive a 100% surface inspection by magnetic particle or liquid penetrant testing after hydrostatic test (see Table 4.4-1). All reactor coolant system plate material was subjected to shear as well as longitudinal ultrasonic testing to give maximum assurance of quality. All forgings received the same inspection. In addition, 100% of the material volume was covered in these tests as an added assurance over the grid basis required in the code.

Quality control engineers monitored the supplier's work, witnessing key inspections not only in the supplier's shop but in the shops of subvendors of the major forgings and plate material. Normal surveillance included verification of records of material, physical and chemical properties, review of radiographs, performance of required tests, and qualification of supplier personnel.

Equipment specification for fabrication required that suppliers submit the manufacturing procedures (welding, heat treating, etc.) which were reviewed by qualified Westinghouse, Vepco, and Stone & Webster engineers. Field fabrication procedures were also reviewed to ensure that installation field welds were of equal quality.

Section III of the ASME Code requires that nozzles carrying significant external loads be attached to the shell by full-penetration welds. This requirement was carried out in the reactor coolant piping, where all auxiliary pipe connections to the reactor coolant loop were made using full-penetration welds.

The reactor coolant system components were welded under procedures that required the use of both pre-heat and post-heat. Pre-heat requirements, not mandatory under code rules, were performed on all weldments, including P1 and P3 materials, which are the materials of construction in the reactor vessel, pressurizer, and steam generators. Pre-heating and post-heating of weldments both served a common purpose: the production of tough, ductile metallurgical structures in the completed weldment. Pre-heating produces tough ductile welds by minimizing the formation of hard zones, whereas post-heating achieves this by tempering any hard zones which may have formed due to rapid cooling.

4.4.1.2 **Electroslag Weld Quality Assurance**

4.4.1.2.1 Piping Elbows

The 90-degree elbows were electroslag-welded. The following were performed for quality assurance of the welding procedures:

1. The electroslag welding procedure employing one-wire technique was qualified in accordance with the requirements of ASME Code Section IX and Code Case 1355, plus supplementary evaluations as requested by Westinghouse. The following test specimens were removed from a 5-inch-thick weldment and successfully tested:

    a. Six transverse tensile bars - as welded.

    b. Six transverse tensile bars - 2050°F, H_2O quench.

    c. Six transverse tensile bars - 2050°F, H_2O + 750°F stress relief heat treatment.

    d. Six transverse tensile bars - 2050°F, H_2O quench, tested at 650°F.

   e. Twelve guided side bend test bars.

2. The casting segments were surface-conditioned for 100% radiographic and penetrant inspections. The acceptance standards were ASTM-E-186 severity level 2, except that no category D or E defectiveness was permitted, and USAS Code Case N-10, respectively.

3. The edges of the electroslag weld preparations were machined. These surfaces were penetrant-inspected prior to welding. The acceptance standard was USAS Code Case N-10.

4. The completed electroslag weld surfaces were ground flush with the casting surface. Then, the electroslag weld and adjacent base material were 100% radiographed in accordance with ASME Code Case 1355. Also, the electroslag weld surfaces and adjacent base material were penetrant-inspected in accordance with USAS Code Case N-10.

5. Weld metal and base metal chemical and physical analyses were determined and certified.

6. Heat treatment furnace charts were recorded and certified.

4.4.1.2.2 Reactor Coolant Pump Casings

The reactor coolant pump casings are electroslag-welded. The following were performed for quality assurance of the components:

1. The electroslag welding procedure employing two- and three-wire technique was qualified in accordance with the requirements of the ASME Code Section TX and Code Case 1355, plus supplementary evaluations as requested by Westinghouse. The following test specimens were removed from an 8-inch-thick and from a 12-inch-thick weldment and successfully tested for both the two-wire and the three-wire techniques, respectively:

   a. Two-wire electroslag process, 8-inch-thick weldment.

      (1) Six transverse tensile bars, 750°F post-weld stress relief.

      (2) Twelve guided side bend test bars.

   b. Three-wire electroslag process, 12-inch-thick weldment.

      (1) Six transverse tensile bar, 750°F post-weld stress relief.

      (2) Seventeen guided side bend test bars.

      (3) Twenty-one Charpy V-notch specimens.

      (4) Full section macroexamination of weld- and heat-affected zones.

      (5) Numerous microscopic examinations of specimens removed from the weld- and heat-affected zone regions.

      (6) Hardness survey across weld- and heat-affected zones.

2. A separate weld test was made using the two-wire electroslag technique to evaluate the effects of a stop and restart of welding by this process. This evaluation was performed to

establish proper procedures and techniques, as such an occurrence was anticipated during production applications due to potential equipment malfunction, power outages, etc. The following test specimens were removed from an 8-inch-thick weldment in the stop-restart-repaired region and successfully tested:

a. Two transverse tensile bars - as welded.

b. Four guided side bend test bars.

c. Full section macroexamination of weld- and heat-affected zone.

3. All of the weld test blocks in 1 and 2 above were radiographed using a 24-MeV Betatron. The radiographic quality level (ASTM-E-94) obtained was between 0.5 to 1%. There were no discontinuities evident in any of the electroslag welds.

   a. The casting segments were surface-conditioned for 100% radiographic and penetrant inspections. The radiographic acceptance standards were ASTM-E-186 severity level 2, except that no category D or E defectiveness was permitted, for section thickness up to 4.5 inch, and ASTM-E-280 severity level 2 for section thicknesses greater than 4.5 inch. The penetrant acceptance standards were ASME Code Section III, paragraph N-627.

   b. The edges of the electroslag weld preparations were machined. These surfaces were penetrant-inspected prior to welding. The acceptance standards were ASME Code Section III, paragraph N-627.

   c. The completed electroslag weld surfaces were ground flush with the casting surface. Then, the electroslag weld and adjacent base material were 100% radiographed in accordance with ASME Code Case 1355. Also, the electroslag weld surfaces and adjacent base material were penetrant-inspected in accordance with ASME Code Section III, paragraph N-627.

   d. Weld metal and base metal chemical and physical analyses were determined and certified.

   e. Heat treatment furnace charts were recorded and certified.

4.4.1.3 **Continuous Drive Friction Weld Process**

Unit 1 CRDM nozzle to adapter welds were performed by the Continuous Drive Friction process. This process is not permitted by the ASME Code Section III, but is approved by the R-CCM Code and has been used extensively for this application in non-U.S. nuclear plants. The Welding Procedure Specification (WPS), the supporting Procedure Qualification Record (PQR) and Welding Operator Performance Qualification (WPQ) were reconciled to ASME Section IX requirements for the CRDM welds. The destructive tests of the supporting PQR were compared with the required tests and criteria of the ASME Code for an equivalent full penetration weld. These welds are deemed acceptable for this application for Surry Unit 1.

4.4.1.4 Reactor Coolant System Field Erection and Welding

Field erection and field welding of the reactor coolant system was performed so as to permit exact fit-up of the 31-inch i.d. closure pipe subassemblies between the steam generator and the reactor coolant pump. After installation of the pump casing and the steam generator, measurements were taken of the pipe length required to close the loop. Based on the measurements, the 31-inch i.d. closure pipe subassembly was properly machined and then erected and field-welded to the pump suction nozzle and to the steam generator exit nozzle. Thus, upon completion of the installation, the system was essentially of zero stress in the installed position.

4.4.1.5 Reactor Coolant System Cleanliness

Cleaning of the reactor coolant system and associated equipment was accomplished before and/or during erection of various equipment. Stainless steel piping was cleaned in sections as specific portions of the systems were erected. Pipe and units large enough to permit entry by personnel were cleaned by locally applying approved solvents (Stoddart solvent, acetone, and alcohol) and demineralized water, and by using a rotary disk sander or 18-8 wire brush to remove all trapped foreign particles.

4.4.1.6 Reactor Coolant System Testing Following Opening

For normal opening, the integrity of the system in terms of strength is unchanged. Prior to normal operation, even though it was not required, the system was pressurized to 2335 psig (operating pressure + 100 psi) to ensure leaktightness during normal operation.

For repairs on components greater than 2 inches in diameter, the thorough non-destructive testing gives a very high degree of confidence in the integrity of the system, and will detect any significant defects in and near the new welds.

Repairs on components 2 inches in diameter or smaller are relatively minor in comparison, and surface examination ensures a similar standard of integrity. In all cases, the leak test ensures leak tightness during normal operation.

4.4.1.7 Inservice Inspection Capability

During the design phase of the reactor coolant system, careful consideration was given to providing access for both visual and/or non-destructive inspection. To facilitate this program, critical areas of the reactor vessel were mapped during the fabrication phase. This map serves as a reference base for subsequent ultrasonic tests.

The inservice inspection and inservice testing of ASME Code Class 1, 2, and 3 components and supports are performed in accordance with a periodically updated version of the ASME Code and Addenda, as required by 10 CFR 50.55(a). Relief from specific requirements of the Code is provided by written request for approval to the NRC.

Table 4.4-1
REACTOR COOLANT SYSTEM QUALITY ASSURANCE PROGRAM

Component	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
1. Steam generator					
1.1 Tubesheet					
1.1.1 Forging		yes		yes	
1.1.2 Cladding		yes[b]	yes[c]		
1.2 Channel head					
1.2.1 Casting	yes			yes	
1.2.2 Cladding			yes		
1.3 Secondary shell and head					
1.3.1 Plates		yes			
1.4 Tubes		yes			yes
1.5 Nozzles (forgings)		yes		yes	
1.6 Weldments					
1.6.1 Shell, longitudinal	yes			yes	
1.6.2 Shell, circumferential	yes			yes	
1.6.3 Cladding (channel head-tubesheet joint cladding restoration)			yes		
1.6.4 Steam and feedwater nozzle to shell	yes			yes	
1.6.5 Support brackets				yes	
1.6.6 Tube to tubesheet			yes		
1.6.7 Instrument connections (primary and secondary)				yes	
1.6.8 Temporary attachments after removal				yes	
1.6.9 After hydrostatic test (all welds and complete channel head-where accessible)				yes	
1.6.10 Nozzle safe ends	yes		yes		
1.6.11 Nozzle safe ends (if weld deposit)			yes		

a. RT-Radiographic
UT- Ultrasonic
PT- Dye penetrant
MT- Magnetic particle
ET- Eddy current
b. Flat surfaces only
c. Weld deposit areas only
d. Or a UT and ET
e. UT of clad bond-to-base metal
f. Excluding Unit 1 and Unit 2 RVCH

Table 4.4-1 (CONTINUED)
REACTOR COOLANT SYSTEM QUALITY ASSURANCE PROGRAM

Component	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
2. Pressurizer					
2.1 Heads					
2.1.1 Casting	yes			yes	
2.1.2 Cladding			yes		
2.2 Shell					
2.2.1 Plates		yes		yes	
2.2.2 Cladding			yes		
2.3 Heaters					
2.3.1 Tubing[d]		yes	yes		
2.3.2 Centering of element	yes				
2.4 Nozzle		yes	yes		
2.5 Weldments					
2.5.1 Shell, longitudinal	yes			yes	
2.5.2 Shell, circumferential	yes			yes	
2.5.3 Cladding			yes		
2.5.4 Nozzle safe end (if forging)	yes		yes		
2.5.5 Nozzle safe end (if weld deposit)			yes		
2.5.6 Instrument connections			yes		
2.5.7 Support skirt				yes	
2.5.8 Temporary attachments after removal				yes	
2.5.9 All welds and cast heads after hydrostatic test				yes	
2.6 Final assembly					
2.6.1 All accessible surfaces after hydrostatic test				yes	
3. Piping					
3.1 Fittings (castings)	yes		yes		
3.2 Fittings (forgings)		yes	yes		

a. RT-Radiographic
UT- Ultrasonic
PT- Dye penetrant
MT- Magnetic particle
ET- Eddy current
b. Flat surfaces only
c. Weld deposit areas only
d. Or a UT and ET
e. UT of clad bond-to-base metal
f. Excluding Unit 1 and Unit 2 RVCH

Table 4.4-1 (CONTINUED)
REACTOR COOLANT SYSTEM QUALITY ASSURANCE PROGRAM

Component	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
3. Piping (continued)					
3.3 Pipe		yes	yes		
3.4 Weldments					
3.4.1 Circumferential	yes		yes		
3.4.2 Nozzle to run pipe (No RT for nozzles less than 3 inches)	yes		yes		
3.4.3 Instrument connections			yes		
4. Pumps					
4.1 Castings	yes		yes		
4.2 Forgings			yes		
4.2.1 Main shaft		yes	yes		
4.2.2 Main studs		yes	yes		
4.2.3 Flywheel (rolled plate)		yes			
4.3 Weldments					
4.3.1 Circumferential	yes		yes		
4.3.2 Instrument connections			yes		
5. Reactor vessel					
5.1 Forgings					
5.1.1 Flanges[f]		yes		yes	
5.1.2 Studs		yes		yes	
5.1.3 Head adapters[f]		yes	yes		
5.1.4 Head adapter tube[f]		yes	yes		
5.1.5 Instrumentation tube		yes	yes		
5.1.6 Main nozzles		yes		yes	
5.1.7 Nozzle safe ends (if forging is employed)		yes	yes		
5.2 Plates		yes		yes	
5.3 Weldments					
5.3.1 Main steam	yes			yes	

a. RT-Radiographic
UT- Ultrasonic
PT- Dye penetrant
MT- Magnetic particle
ET- Eddy current
b. Flat surfaces only
c. Weld deposit areas only
d. Or a UT and ET
e. UT of clad bond-to-base metal
f. Excluding Unit 1 and Unit 2 RVCH

Table 4.4-1 (CONTINUED)
REACTOR COOLANT SYSTEM QUALITY ASSURANCE PROGRAM

Component	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
5. Reactor vessel (continued)					
5.3 Weldments (continued)					
5.3.3 Instrumentation tube connection			yes		
5.3.4 Main nozzles	yes			yes	
5.3.5 Cladding[f]		yes[e]	yes		
5.3.6 Nozzle safe ends (if forging)	yes		yes		
5.3.7 Nozzle safe ends (if weld deposit)	yes		yes		
5.3.9 All welds after hydrotest				yes	
5.4 Unit 1 Replacement RV Closure Head					
5.4.1 Forgings					
5.4.1.1 Flanges		yes	yes		
5.4.1.2 Head adaptors		yes	yes		
5.4.1.3 Head adaptor tube		yes	yes		
5.4.2 Plates					
5.4.2.1 Closure head dome		yes			
5.4.3 Weldments					
5.4.3.1 CRD head adaptors connection to head			yes		
5.4.3.2 Head adaptors tube to forging		yes	yes		
5.4.3.3 Cladding		yes	yes		
5.4.3.4 Head lifting lugs			yes	yes	
5.5 Unit 2 Replacement RV Closure Head					
5.5.1 Forgings					
5.5.1.1 Closure head		yes		yes	
5.5.1.2 Head adapter forging		yes	yes		
5.5.1.3 Head adapter tubing		yes	yes		

a. RT-Radiographic
UT- Ultrasonic
PT- Dye penetrant
MT- Magnetic particle
ET- Eddy current
b. Flat surfaces only
c. Weld deposit areas only
d. Or a UT and ET
e. UT of clad bond-to-base metal
f. Excluding Unit 1 and Unit 2 RVCH

Table 4.4-1 (CONTINUED)
REACTOR COOLANT SYSTEM QUALITY ASSURANCE PROGRAM

Component	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
5. Reactor vessel (continued)					
5.5 Unit 2 Replacement RV Closure Head (continued)					
5.5.2 Weldments					
5.5.2.1 CRDM head adapters connection to head			yes		
5.5.2.2 RVLIS & head vent pipe connection to head			yes		
5.5.2.3 Cladding		yes	yes	yes	
5.5.2.4 Head lifting lugs		yes		yes	
5.5.2.5 Head adapter forging to head adapter tube	yes		yes		
6. Valves					
6.1 Castings	yes		yes		
6.2 Forgings (No UT for valves 2 inches and smaller)		yes	yes		

a. RT-Radiographic
UT- Ultrasonic
PT- Dye penetrant
MT- Magnetic particle
ET- Eddy current
b. Flat surfaces only
c. Weld deposit areas only
d. Or a UT and ET
e. UT of clad bond-to-base metal
f. Excluding Unit 1 and Unit 2 RVCH

Surry Power Station
Updated Final Safety Analysis Report

Chapter 5

Intentionally Blank

Chapter 5: Containment System
Table of Contents

Chapter 5: Containment System
Table of Contents (continued)

Chapter 5: Containment System

List of Tables

Chapter 5: Containment System

List of Figures

CHAPTER 5 CONTAINMENT SYSTEM

This section describes the containment system for either unit. The containment systems for the two units are similar and completely independent.

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

5.1 GENERAL DESCRIPTION

The containment system, together with the engineered safeguards (Chapter 6), is designed to limit radiation doses under conditions resulting from design-basis accident (Chapter 14) to less than or equal to the limits specified in 10 CFR 50.67 at the site boundary and beyond.

The steel-lined, reinforced-concrete containment structure, including foundations, access openings, and penetrations are designed and constructed to maintain full containment integrity when subjected to the temperatures, pressures, potential missiles resulting from the design-basis accident, and the earthquake conditions and tornados described in Chapter 2. Systems are provided to remove heat from the containment and to ensure against breaching containment integrity at the time of, or following, the design-basis accident, or any lesser accident.

The original containment concept includes provisions for routine operation at a reduced internal pressure in which the air partial pressure varies between about 9.0 and 10.3 psia, and for the return to subatmospheric pressure within 60 minutes after the design-basis accident through the use of multiple spray systems. This concept provides for positive termination of outleakage of fission products from the containment, since the containment is maintained at subatmospheric pressure after depressurization. The pressure following depressurization is maintained at less than 14.7 psia. The current concept for the design basis accident containment internal pressure reduction, consistent with alternate source term (AST) analysis, is discussed in Section 5.4.

Provisions have been made for the leak testing of liner seams during construction; for air pressure and leak testing of the containment structure at the completion of construction; for leak testing of the penetrations and access openings at any time; for continuous leak monitoring of the containment structure while at subatmospheric pressure; and for periodic pressure testing of the containment structure throughout station life.

Leak tightness testing of liner welds during construction was performed by welding a structural steel gas test channel over each weld. The test channels of the dome of the containment are located outside the liner plate, with test holes tapped and plugged from the inside. Test channels of the floor liner are piped through the concrete, which covers the floor, to test port panels, and are plugged. Test channels on the straight side walls of the containment are located inside the liner plate, and are tapped and plugged from the inside.

The containment weld test channels used for leak testing of the containment liner welds as described in Section 5.5 were left in place at the completion of construction. Therefore, the test channel welds are tested as an integral part of the containment liner plate welds during the operational phase leak rate testing.

Although the leak test channels were not designed as structural elements, nor as a pressure boundary, they do provide additional leak protection. The test channels are capable of withstanding all loads that might be imposed on them during normal, test, and design basis accident conditions without any loss of function, and the presence of the test channels does not in any way impair the performance of the containment liner itself.

Details of containment structural design are given in Chapter 15, and details related to performance during postulated accident situations are given in Section 5.4 and Chapter 14.

5.1 REFERENCES

1. Virginia Power letter dated August 5, 1988, (Serial No. 88-707B), Containment Liner Test Channels.
2. NRC SER dated March 6, 1989, (Serial No. 89-184), Surry Units 1 & 2 Containment Liner Weld Leak Chase Channels.

5.2 CONTAINMENT ISOLATION

5.2.1 Design Bases

The containment isolation system has the following design bases:

1. During incident conditions, at least two barriers exist between the atmosphere outside the containment structure and:
   a. The atmosphere inside the containment structure.
   b. The reactor coolant and connecting systems.
2. The design pressure of all piping and connecting components within the isolation boundary is greater than the design pressure of the containment, 45 psig.
3. The failure of one valve or barrier does not prevent isolation.
4. The operation of the containment isolation system is automatic.
5. All isolation valves and equipment are protected from missiles and water jets originating from the reactor coolant system.
6. All remotely actuated and automatically operated isolation valves have their positions indicated in, and can be operated from, the control room.
7. Containment isolation system valves are located so as to require a minimum length of piping between the isolation valves and their penetrations.
8. Special consideration is given to the design of the low-head safety injection and recirculation spray pump inlet lines, in that highly reliable components are used in a single valve arrangement, which is enclosed in a special valve pit.

For isolation, the two-barrier valving arrangements consist of the following:

1. Two automatic isolation valves one on each side of the containment wall.
2. Two automatic isolation valves located outside the containment wall.
3. An automatic isolation valve and a membrane barrier. A membrane barrier consists of either pipe, tubing, or a component wall.
4. An administratively-controlled, manually-operated valve outside the containment, and a closed system inside the containment.
5. Two administratively-controlled, manually-operated valves, one on each side of the containment wall.

6. A sump recirculation pipe and valve arrangement, conservatively designed and fabricated, and enclosed by a special valve pit. The suction lines for the low-head safety injection pumps and the recirculation-spray pumps are designed to prevent gross system leakage. The major portion of this piping is buried in the reinforced-concrete base mat, and only a short length of piping exists between the mat and the isolation valve. This valve is equipped with a reliable remote operator. The design of this portion of the installation is compatible with letters from the Advisory Committee on Reactor Safeguards to the U.S. Atomic Energy Commission (References 1 & 2). Provisions for detecting leaks in these suction lines are described in Chapter 6.

The criteria applied to the various functional classes of piping to implement the design bases are as follows:

1. Class I piping is open to the outside atmosphere and is connected to the reactor coolant system, or a connecting system, or is open to the containment atmosphere. An example is the line from the containment sump pumps to the waste drain tanks. For Class I piping, the following is provided for isolation subsequent to a LOCA:
    a. Incoming lines with one check valve inside the containment wall and an automatic isolation valve outside the containment.
    b. Outgoing lines with one automatic isolation valve inside and one automatic isolation valve outside the containment wall or two automatic isolation valves outside the containment wall.
2. Class II piping is connected to a closed system outside the containment and is connected to the reactor coolant system, or a connecting system, or is open to the containment atmosphere. An example is the excess letdown line. For Class II piping, the following is provided for isolation subsequent to a LOCA:
    a. Incoming lines with one check valve inside the containment wall and one automatic isolation valve outside the containment wall.
    b. Outgoing lines with one automatic isolation valve.
3. Class III piping is connected to open systems outside the containment and is separated from the reactor coolant system, or a connecting system, and the containment atmosphere by a valve under administrative control or by a membrane barrier. Examples are the component cooling-water lines. For Class III piping, the following is provided for isolation subsequent to a LOCA:
    a. Incoming lines with one check valve inside the containment wall and a valve under administrative control outside the containment wall.
    b. Outgoing lines with one automatic isolation valve or a valve under administrative control outside the containment wall.

In the case of the main feedwater and auxiliary feedwater systems, isolation of the Class III lines is provided by one check valve inside and one check valve outside the containment wall. Isolation of the steam supply to the turbine driven auxiliary feedwater pump is provided by a normally open manual valve under procedural control. Isolation of the service water lines to the Recirculation Spray Heat Exchangers is provided by the closed membrane system inside of the containment wall and a remote manual isolation valve outside the containment wall in each line.

4. Class IV piping must remain open after a LOCA. An example is the high-head safety injection/charging pump header to the reactor coolant system. For Class IV piping, the following is provided for isolation subsequent to a LOCA:

   a. Incoming lines with one check valve inside the containment wall and one remote manual valve outside the containment wall.

   b. Outgoing lines with one automatic isolation valve outside the containment wall.

   Isolation for the seal water supply to the Reactor Coolant Pumps (RCP) is provided by two check valves inside the containment wall and one administratively controlled manual valve outside the containment. Isolation barriers are provided by the check valves inside containment and the closed portion of the chemical and volume control system on the discharge of the charging pumps. These lines remain open after a safety injection signal, and the flow contributes to the total injection flow while cooling the RCP seals.

5. Class V piping is connected to systems outside the containment wall, which are normally not in service and are isolated by a normally closed isolation valve under administrative control. A Class V line is separated from the reactor coolant system, connecting systems, and the containment atmosphere by a closed valve and/or by a membrane barrier. An example is the service air line.

The isolation valve configuration for each penetration is provided in Tables 5.2-1 and 5.2-2 for Units 1 and 2, respectively.

Where check valves are used as isolation valves, consideration has been given to the ability of these check valves to prevent the leakage of air into the containment when the containment atmospheric pressure is negative.

Check valves in the containment spray and recirculation spray systems are positive-closure check valves. These valves have an external, adjustable counterweight, set to maintain the disk tightly sealed during certain phases of accident conditions when the containment atmospheric pressure is slightly negative. These types of check valves are provided in these systems because they are open to the containment atmosphere through the spray nozzles when the systems are isolated after an accident.

Check valves used for isolation purposes in other pipelines, normally those containing water, are ordinary check valves. They do not have the positive closure feature because they are in series with an automatic trip valve or a valve under administrative control. This arrangement would require a double failure; that is, a failure of the automatic trip valve to close and a rupture in the line downstream from the check valve, which would cause the water leg normally holding the check valve closed and sealed to be drained. This allows outward leakage past the check valve if the check valve fails to seal tightly with a small differential air pressure.

A monitoring arrangement is provided to test the leaktightness of each automatically actuated trip valve and check valve. Examples of valve arrangements for each class of penetration are depicted in Figure 5.2-1.

Instrumentation and adjunct control circuits associated with automatic isolation valve closure are fail-safe (initiate closure) upon loss of voltage and/or control air. Most isolation valves are air-to-open/spring-return-closure diaphragm-operated, piston-operated or direct acting electric solenoid valves thus providing a fail-safe design. The automatic isolation valves inside the containment will function properly under all containment atmospheric pressures.

Under accident conditions, the containment pressure is positive and the solenoid valve vents the control air to the containment atmosphere. Because both sides of the isolation valve diaphragm are vented, balanced forces on either side of the diaphragm result, allowing the spring to close the automatic isolation valve. Circuits that control redundant automatic valves are redundant in the sense that no single failure will preclude isolation. Means are provided to periodically test the functioning of the automatic isolation equipment such as the setpoint of sensors, the speed of response, and the operability of fail-safe features. The containment isolation instrumentation is discussed in Section 7.5.

It should be noted that isolation valves actuated by electric motors upon electrical failure fail in the as-is position.

The trip valves in the reactor coolant sample system and the residual heat removal sample systems are direct acting electric solenoid valves. This ensures that the valves could be reopened to draw a sample under single failure criteria, after an accident.

The steam generator blowdown trip valves are 2-inch, double disk, pressure seal-type gate valves. The valves are of sufficient size to meet the maximum allowable pressure-drop requirement at the design flow rate and will minimize the occurrence of cavitation.

5.2.2 Isolation Design

The general criteria covering the number and location of isolation valves required to ensure containment integrity during LOCA conditions are provided in Section 5.2.1. Tables 5.2-1 and 5.2-2 for Units 1 and 2, respectively, summarizes the major piping penetrations through the containment for each fluid system as to the type of valves that are provided, their position under various plant conditions, the fluid they contain and the systems they connect. The tables also identify if the system is essential or non-essential and the isolation actuation signals. In addition, the tables identify those valves that are required to be leak tested in accordance with 10 CFR 50 Appendix J.

The isolation valves tested in accordance with 10 CFR 50 Appendix J provide containment integrity during LOCA conditions. The remaining isolation valves, which are not required to be tested in accordance with 10 CFR 50 Appendix J, provide isolation to mitigate the consequences of other accident conditions (e.g., mainsteam, feedwater and blowdown valves are not tested, but provide isolation in the event of a steam generator tube rupture).

Containment isolation is accomplished under the following conditions:

1. Phase-1 isolation is initiated by a safety injection actuation signal. Safety injection is actuated by any one of the following input signals (Section 7.5):

    a. High steam-line flow with low steam-line pressure or low-low T_{avg}.

    b. High steam-line differential pressure.

    c. Low-low pressurizer pressure.

    d. High containment pressure.

    e. Manual initiation.

    These input signals provide the diversity required by Section 6.2.4 of the Standard Review Plan (Reference 3).

2. Phase 2 - Isolation is initiated by a high containment pressure signal, and closes the automatic trip valves in all normally open lines penetrating the containment that are not required to be open to control containment pressure to perform an orderly shutdown without actuation of the consequence limiting safeguards in case of a small reactor coolant system leak.

3. Phase 3 - Isolation is initiated by a high-high containment pressure signal, which is indicative of a major LOCA. Remaining automatic trip valves normally open lines that penetrate the containment which have not been shut by 2. above are shut by this signal.

Plant systems with containment penetrations have been categorized as essential or non-essential. There are, in turn, two levels of essential systems:

Level 1 - Systems required to mitigate the consequences of an accident.

Level 2 - Systems required to maintain the operability of critical systems or functions.

Level 1 essential systems (Tables 5.2-1 & 5.2-2) include the engineered safety features (such as containment spray, recirculation spray, and the safety injection system) and the service-water system used to cool the recirculation-spray heat exchangers. Level 2 essential systems (Tables 5.2-1 & 5.2-2) include the auxiliary feedwater system, the component cooling-water system associated with reactor coolant pump operation, containment air cooling, and residual heat removal. Non-essential systems (Tables 5.2-1 & 5.2-2) include the other systems not required for the Level 1 and Level 2 functions described above.

Level 1 essential systems are required to operate after a LOCA. Level 2 essential systems remain unisolated from containment unless they are not required, or until a LOCA is indicated by Phase 2 isolation. Non-essential systems are either isolated during normal operation or they are isolated by a Phase 1 isolation signal. Some non-essential systems may be operated manually following a LOCA if conditions warrant their use.

Once Phase 1 containment isolation has been initiated by a safety injection actuation signal, the automatic isolation valves can be opened only after the manual reset of the actuating signal and the deliberate remote manual operation of the individual valve (an exception is the condenser air ejector containment isolation valve described in the next paragraph). There are no valve control switches that control the reopening of more than one valve.

Under normal conditions, the condenser air ejector discharge is vented to the atmosphere and the containment discharge divert valve is closed. When high radioactivity is detected by the condenser air ejector radiation monitors, the normal condenser air ejector discharge flow path to atmosphere is isolated and the containment divert valve opens to divert the condenser air ejector discharge to containment. If a containment isolation (safety injection) signal occurs, the condenser air ejector containment isolation trip valve will close. When the containment isolation signal resets, the condenser air ejector containment isolation trip valve will open and divert the condenser air ejector discharge back to the containment if the high radioactivity signal is still present. The isolation valve has an electrical interlock, however, that prevents reset until containment pressure is subatmospheric. Normal flow to the atmosphere is not restored until the high radiation signal is cleared. See Sections 10.3.8.2 and 11.3.3.8 for further information.

Diverse isolation signals are provided for the automatic containment isolation valves in non-essential systems. However, some non-essential systems are not automatically isolated by a containment isolation signal. But the staff of the Nuclear Regulatory Commission has agreed that sufficient isolation provisions have been provided at Surry for all non-essential penetrations (Reference 4). Penetrations with normally closed manual isolation valves are locked closed and administratively controlled such that, if a valve is required to be opened during plant operation, a dedicated person is assigned to close it after the evolution requiring it to be open has been completed, or to close it within 60 seconds after the receipt of a containment isolation signal.

The basis for the 60-second limit is that no fuel cladding is expected to melt or fail until after 60 seconds following a loss-of-coolant accident (LOCA). This is verified for PWRs by the FLECHT experimental results (Reference 7). Thus, fission product release from the core to the containment atmosphere or to other portions of the Reactor Coolant System (RCS) could not occur until at least one minute after the event.

If any of the automatic signals fail to actuate the containment isolation trip valves or the remote manual valves, isolation can be accomplished manually from the control room. The solenoid valves that operate the automatic trip valves can be actuated by an electric signal that is produced in the control room.

For lines coming into the containment, check valves are used wherever an additional barrier is provided by either a membrane or an automatic isolation valve. The use of check valves in this service is confined to either liquid lines or lines that are closed outside the containment. These check valves shut under a differential pressure when the higher pressure is on the containment side of the check valve.

The monitoring arrangement provided to test the leaktightness of each automatic trip valve and check valve consists of a monitoring tap on the main line upstream from each isolation valve. To test for valve tightness, the main piping section upstream from each valve is pressurized and evidence of fluid leakage is checked using the makeup air method. When not in use, the monitoring lines are plugged at the open end. As described in Section 5.5, containment isolation valves are tested to verify their sealing capability and leaktightness.

Several spare containment pipe penetrations of various sizes are provided. All pipes in these spare penetrations are sealed at both ends.

All isolation valves and equipment are protected from missiles and water jets originating from the reactor coolant system. Missile protection for isolation valves, actuators, and controls is provided by locating isolation valves between the steam generator cubicle wall, crane wall, and the containment wall or locating isolation valves outside the containment structure. The pressure-sensing devices that detect high containment pressure are located outside the containment on the leakage-monitoring tubing that is open to the containment. The location of the pressure-sensing devices outside the containment protects them from missiles developed by a LOCA. Details regarding the probability of missile damage and design features to prevent the formation of missiles are given in Section 15.5.1.11.

The fuel transfer penetration between the refueling canal inside the containment and the spent-fuel pit is fitted with a blind flange inside the containment and a normally closed gate valve in the transfer canal outside the containment to prevent leakage through the transfer tube during accident conditions.

The following precautions, which apply to all lines penetrating the containment, are intended to prevent the inadvertent opening of these lines to the atmosphere outside the containment:

1. Automatic isolation valves can be opened only upon the cessation of the actuating signal and the manual reset of controls.
2. Automatic isolation valves are capable of manual actuation from the control room, with the limitations on the opening of the valve discussed in item 1. above.
3. Remote manual valves are closed and opened only under administrative control.

4. Local manual valves are closed and opened under administrative control.
5. Check valves open only when the fluid pressure is higher on the side outside the containment.
6. The design pressure of piping and connecting components within the isolation boundary is greater than the design pressure of the containment (45 psig).
7. Remote manual valves, once opened by a high-containment-pressure isolation signal, can only be closed upon the cessation of the actuating signal and the manual reset of controls.

For items 1, 2, 3, and 4 above, and for flanged closures, specific plant procedures define the positioning of these closures in the containment isolation system during normal operation, shutdown, and accident conditions.

5.2 REFERENCES

1. Letter from S. H. Hanauer, Advisory Committee on Reactor Safeguards, to G. T. Seaborg, AEC, Subject: *Report on Edwin I. Hatch Nuclear Plant,* dated May 15, 1969.
2. Letter from S. H. Hanauer, Advisory Committee on Reactor Safeguards, to G. T. Seaborg, AEC, Subject: *Report on Brunswick Steam Electric Plant.*
3. Standard Review Plan, Section 6.2.4, *Containment Isolation System*.
4. U.S. Nuclear Regulatory Commission, *Evaluation of Licensee's Compliance with Category 'A' Items of NRC Recommendations Resulting from TMI-2 Lessons Learned,* April 24, 1980.
5. U.S. Nuclear Regulatory Commission, *Exemption from Appendix J, 10 CFR 50 for Surry Unit 2,* dated November 21, 1988.
6. U.S. Nuclear Regulatory Commission, *Exemption from Appendix J, 10 CFR 50 for Surry Unit 1,* dated August 7, 1990.
7. Westinghouse Report WCAP-7544, *PWR FLECHT Group II Test Report,* September 1970.

Table 5.2-1
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
CCW from 'B' RHR HX	001	18"	3	None	1-CC-TV-109B Butterfly/Air Pilot	-	No	2	No	SI			C	-/FC	Out	Cold	Liquid	1
CCW to 'A' RHR HX	002	18"	3	1-CC-177 Check	1-CC-214 Butterfly/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to 'B' RHR HX	004	18"	3	1-CC-176 Check	1-CC-220 Butterfly/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW from 'A' RHR HX	005	18"	3	None	1- CC-TV-109A Butterfly/Air Pilot	-	No	2	No	SI			C	NA/FC	Out	Cold	Liquid	1
High Head SI (Normal header)	007	3"	4	1-SI-225 Check	1-SI-150 Globe/Manual	No	No[a]	1	Yes	SI	LC	LC	LC	NA/LC	In	Cold	Liquid	2, 4, 9
					1-SI-MOV-1867D Gate/Motor	-	No[a]				C	C	O	-/FAI				
					1-SI-MOV-1867C Gate/Motor	-	No[a]				C	C	O	-/FAI				
CCW to 'C' Air Recirc. Fan	009	6"	3	1-CC-224 Check	1-CC-223 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to 'B' Air Recirc. Fan	010	6"	3	1-CC-233 Check	1-CC-232 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to 'A' Air Recirc. Fan	011	6"	3	1-CC-242 Check	1-CC-241 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW from 'B' Air Recirc. Fan	012	6"	3	None	1-CC-TV-110B Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from 'C' Air Recirc Fan	013	6"	3	None	1-CC-TV-110C Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from 'A' Air Recirc Fan	014	6"	3	None	1-CC-TV-110A Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
Chemical and Volume Control	015	3"	2	1-CH-309 Check	1-CH-MOV-1289A Gate/Motor	No	No[a]	No	No	SI	O	O	C	NA/FAI	In	Cold	Liquid	9
CCW to 'C' RCP	016	6"	3	1-CC-59 Check	1-CC-216 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]: Normal	Line Status[c, d]: Shut-down	Line Status[c, d]: Incident	Line Status[c, d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
CCW to ‘B’ RCP	017	6"	3	1-CC-58 Check	1-CC-218 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to ‘A’ RCP	018	6"	3	1-CC-1 Check	1-CC-219 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
Seal Water from RCPs	019	3"	2	None	1-CH-MOV-1381 Gate/Motor	-	Yes	No	No	SI	O	O	C	-/FAI	Out	Cold	Liquid	
Safety Injection Accumulator Makeup	020	1"	5	1-SI-HCV-1851A Globe/Air Pilot	1-SI-32 Globe/Manual	No	Yes	No	No	-	LC	LC	LC	FC/NA	In	Cold	Liquid	3, 4
				1-SI-HCV-1851B Globe/Air Pilot		No	-							FC/-				
				1-SI-HCV-1851C Globe/Air Pilot		No	-							FC/-				
High Head Safety Injection to Cold Leg (Alternate header)	021	3"	4	1-SI-224 Check	1-SI-MOV-1842 Gate/Motor	No	No[a]	1	Yes	-	C	C	INT	NA/FAI	In	Cold	Liquid	2, 9
High Head Safety Injection to Hot Leg	023	3"	4	1-SI-226 Check	1-SI-MOV-1869B Gate/Motor	No	No[a]	1	Yes	-	C	C	INT	NA/FAI	In	Cold	Liquid	2, 9
RHR to RWST	024	6"	5	1-RH-47 Gate/Manual	1-RH-100 Gate/Manual	Yes	Yes	No	No	-	LC	INT	LC	NA/FAI	Out	Cold	Liquid	3, 4
CCW from ‘A’ RCP	025	6"	3	None	1-CC-TV-105A Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from ‘C’ RCP	026	6"	3	None	1-CC-TV-105C Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from ‘B’ RCP	027	6"	3	None	1-CC-TV-105B Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
Reactor Coolant Letdown	028	2"	2	1-CH-TV-1204A Globe/Air Pilot	1-CH-TV-1204B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Hot	Liquid	

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]: Normal	Line Status[c, d]: Shut-down	Line Status[c, d]: Incident	Line Status[c, d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
Gaseous Waste	032	3/8" valve, 3" penetration	1	None	1-GW-TV-106 Globe/Air Pilot	-	Yes	No	No	-	C	C	C	-/FC	In	Cold	Gas	
					1-GW-TV-107 Globe/Air Pilot	-	Yes											
Primary Drain Transfer Tank Pump Discharge	033	2"	1	1-DG-TV-108A Globe/Air Pilot	1-DG-TV-108B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Cold	Liquid	
Seal Water to ‘C’ RCP	035	2"	4	1-CH-349 Check	1-CH-300 Needle/Manual	No	No	1	No	-	O	O	O	NA	In	Cold	Liquid	2, 5
Seal Water to ‘A’ RCP	036	2"	4	1-CH-323 Check	1-CH-294 Needle/Manual	No	No	1	No	-	O	O	O	NA	In	Cold	Liquid	2, 5
Seal Water to ‘B’ RCP	037	2"	4	1-CH-333 Check	1-CH-297 Needle/Manual	No	No	1	No	-	O	O	O	NA	In	Cold	Liquid	2, 5
Aerated Drain Sump Pump Discharge	038	2"	1	1-DA-TV-100A Ball/Air Pilot	1-DA-TV-100B Ball/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Cold	Liquid	
SG Blowdown-1A	039	3"	3	1-BD-TV-100A Gate/Air Pilot	1-BD-TV-100B Gate/Air Pilot	No	No	No	No	AFW	O	O	C	FC/FC	Out	Hot	Liquid	7
SG Blowdown-1C	040	3"	3	1-BD-TV-100E Gate/Air Pilot	1-BD-TV-100F Gate/Air Pilot	No	No	No	No	AFW	O	O	C	FC/FC	Out	Hot	Liquid	7
SG Blowdown-1B	041	3"	3	1-BD-TV-100C Gate/Air Pilot	1-BD-TV-100D Gate/Air Pilot	No	No	No	No	AFW	O	O	C	FC/FC	Out	Hot	Liquid	7
Service Air Supply	042	2"	5	None	1-SA-60 Gate/Manual	-	Yes	No	No	-	LC	INT	LC	NA	In	Cold	Gas	4
					1-SA-62 Gate Manual	-	Yes											
Particulate and Gaseous Rad Monitoring Return	043	1"	1	1-RM-3 Check	1-RM-TV-100A Globe/Air Pilot	Yes	Yes	No	No	H	O	O	C	NA/FC	In	Cold	Gas	

a. See Note 9

b. Cold < 250°F; Hot > 250°F

c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed

d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable

e. I/O = Inside/Outside

f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
Particulate and Gaseous Rad Monitoring Supply	044	1"	1	1-RM-TV-100C Globe/Air Pilot	1-RM-TV-100B Globe/Air Pilot	Yes	Yes	No	No	H	O	O	C	FC/FC	Out	Cold	Gas	
Primary Grade Water to PRT	045	3"	1	1-RC-160 Check	1-RC-TV-1519A Diaphragm/Air Pilot	Yes	Yes	No	No	SI	INT	C	C	NA/FC	In	Cold	Liquid	
Loop Fill Header	046	2"	5	1-RC-HCV-1556A Globe/Air Pilot		No	No[a]	No	No	-	C	INT	C	FC/FC	In	Cold	Liquid	3, 9
				1-RC-HCV-1556B Globe/Air Pilot	1-CH-FCV-1160 Globe/Air Pilot	No	-							FC/-				
				1-RC-HCV-1556C Globe/Air Pilot		No	-							FC/-				
Instrument Air Supply	047	2"	1	1-IA-939 Check	1-IA-TV-100 Globe/Air Pilot	Yes	Yes	No	No	HH	O	O	C	NA/FC	In	Cold	Gas	4
					1-IA-446 Gate/Manual	-	Yes				INT/LC	O	INT/LC	-/NA				
Primary Vent Header	048	2"	1	1-VG-TV-109A Globe/Air Pilot	1-VG-TV-109B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Cold	Gas	
Accumulator Vent Header to Gaseous Waste	050	1"	1	1-SI-TV-101A Globe/Air Pilot	1-SI-TV-101B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O/INT	C	FC/FC	Out	Cold	Gas	
Recirc Spray HX SW Drains	051	2"	5	1-SW-206 Gate/Manual	1-SW-208 Gate/Manual	Yes	Yes	No	No	-	LC	INT	LC	NA	Out	Cold	Liquid	4
Nitrogen to PRT	053	1"	2	1-SI-234 Check	1-SI-TV-100 Globe/Air Pilot	Yes	Yes	No	No	SI	INT	C	C	NA/FC	In	Cold	Gas	
Primary Vent Pot Vent	054	2"	5	1-VA-6 Gate/Manual	1-VA-1 Gate/Manual	Yes	Yes	No	No	-	LC	O/INT	LC	NA	Out	Cold	Gas	4
Leakage Monitoring	055A	3/8”	1	None	1-LM-TV-100F Globe/Air Pilot	-	Yes	No	No	SI	C	C	C	-/FC	Out	Cold	Gas	4
					1-LM-TV-100E Globe/Air Pilot	-	Yes											

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)

UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]: Normal	Line Status[c, d]: Shut-down	Line Status[c, d]: Incident	Line Status[c, d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
Pressurizer Liquid Sample	056A	3/8”	1	1-SS-TV-100A Globe/Air Pilot	1-SS-TV-100B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	-/FC	Out	Cold	Liquid	
RCS Cold Leg Sample	056B	3/8”	1	1-SS-TV-102A Globe/Air Pilot	1-SS-TV-102B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Liquid	
RCS Hot Leg Sample	056D	3/8”	1	1-SS-TV-106A Globe/Air Pilot	1-SS-TV-106B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Liquid	
Leakage Monitoring	057A	3/8”	1	None	1-LM-TV-100H Globe/Air Pilot	-	Yes	No	No	SI	INT	INT	C	-/FC	Out	Cold	Gas	4
					1-LM-TV-100G Globe/Air Pilot	-	Yes							-/FC				
PRT Sample	057B	3/8”	1	1-SS-TV-104A Globe/Air Pilot	1-SS-TV-104B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Gas	
Pressurizer Steam Space Sample	057C	3/8”	1	1-SS-TV-101A Globe/Air Pilot	1-SS-TV-101B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Gas	
Post Accident Sample Return	057D	2"	1	None	1-DA-TV-103A Globe/Air Pilot	-	Yes	No	No	SI	INT	INT	C	-/FC	In	Cold	Liquid	
					1-DA-TV-103B Globe/Air Pilot	-	Yes							-/FC				
Instrument Air from Unit 2	058	2"	5	1-IA-938 Check	2-IA-446 Gate/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	In	Cold	Gas	4
‘A’ Low Head SI Pump Discharge to Hot Legs	060	6"	4	1-SI-229 Check	1-SI-MOV-1890A Gate/Motor	No	No[a]	1	Yes	-	C	C	C/INT	NA/FAI	In	Cold	Liquid	2, 9
		3"	5	1-SI-500/Globe	Valve/Manual	No	No[a]	1	Yes	-	C	C	C	NA/FAI	In	Cold	Liquid	2, 4, 9

a. See Note 9

b. Cold < 250°F; Hot > 250°F

c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed

d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable

e. I/O = Inside/Outside

f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
Low Head SI Pumps Discharge to Cold Legs	061	6”	4	1-SI-243 Check	1-SI-MOV-1890C Gate/Motor	No	No[a]	1	Yes	-	O	-	O	NA/FAI	In	Cold	Liquid	2, 6, 9
				1-SI-242 Check		No	-							NA/-				
				1-SI-241 Check		No	-							NA/-				
‘B’ Low Head SI Pump Discharge to Hot Legs	062	6"	4	1-SI-228 Check	1-SI-MOV-1890B Gate/Motor	No	No[a]	1	Yes	-	C	C	C/INT	NA/FAI	In	Cold	Liquid	2, 9
‘B’ CS Pump Discharge to Spray Ring	063	8"	4	1-CS-24 Check	1-CS-MOV-101C Butterfly/Motor	Yes	Yes	1	Yes	HH	C	C	O	NA/FAI	In	Cold	Liquid	
					1-CS-MOV-101D Butterfly/Motor	-	Yes							NA/FAI				
‘A’ CS Pump Discharge to Spray Ring	064	8"	4	1-CS-13 Check	1-CS-MOV-101A Butterfly/Motor	Yes	Yes	1	Yes	HH	C	C	O	NA/FAI	In	Cold	Liquid	
					1-CS-MOV-101B Butterfly/Motor	-	Yes							NA/FAI				
‘A’ ORS Pump Suction from Containment Sump	066	12"	4	None	1-RS-MOV-155A Plug/Motor	-	No[a]	1	Yes	HH	O	O	O	-/FAI	Out	Cold	Liquid	4, 9
					1-RS-52 Gate/Manual	-	No[a]				LC	LC	LC	NA				
‘B’ ORS Pump Suction from Containment Sump	067	12"	4	None	1-RS-MOV-155B Plug/Motor	-	No[a]	1	Yes	HH	O	O	O	-/FAI	Out	Cold	Liquid	4, 9
					1-RS-46 Gate/Manual	-	No[a]				LC	LC	LC	NA				
‘B’ Low Head SI Suction from Containment Sump	068	12"	4	None	1-SI-MOV-1860B Gate/Motor	-	No[a]	1	Yes	-	C	C	INT	-/FAI	Out	Cold	Liquid	4, 9
					1-SI-311 Gate/Manual	-	No[a]				LC	LC	LC	NA				

a. See Note 9

b. Cold < 250°F; Hot > 250°F

c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed

d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable

e. I/O = Inside/Outside

f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]: Normal	Line Status[c, d]: Shut-down	Line Status[c, d]: Incident	Line Status[c, d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
‘A’ Low Head SI Suction from Containment Sump	069	12"	4	None	1-SI-MOV-1860A Gate/Motor	-	No[a]	1	Yes	-	C	C	INT	-/FAI	Out	Cold	Liquid	4, 9
					1-SI-301 Gate/Manual	-	No[a]				LC	LC	LC	NA				
‘B’ ORS Pump Discharge to Spray Ring	070	10"	4	1-RS-11 Check	1-RS-MOV-156B Butterfly/Motor	Yes	Yes	1	Yes	HH	O	O	O	NA/FAI	In	Cold	Liquid	
‘A’ ORS Pump Discharge to Spray Ring	071	10"	4	1-RS-17 Check	1-RS-MOV-156A Butterfly/Motor	Yes	Yes	1	Yes	HH	O	O	O	NA/FAI	In	Cold	Liquid	
‘A’ Main Steam Header	073	30"	3	None	1-MS-TV-101A Check/Air Pilot	-	No	No	No	SI or HH	O	C	C	-/FC	Out	Hot	Steam	7
					1-MS-84 Gate/Manual	-	No				C	C	C	-/NA				
		4"	-	None	1-MS-87 Gate/Manual	-	No				O	O	O	-/NA				6
					1-MS-379 Gate/Manual	-	No				C	C	C	-/NA				
		3"	-	None	1-MS-NRV-102A Stop Check/Manual	-	No				C	C	C	-/NA				
		2"	-	None	1-GN-1 Gate Manual	-	No				C	C	C	-/NA				
		1-1/2”	-	None	1-MS-266 Gate Manual	-	No				C	C	C	-/NA				
		4"	-	None	1-MS-SV-101A Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-102A Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-103A Safety	-	No				C	C	C	-/NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
		6"	-	None	1-MS-SV-104A Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-105A Safety	-	No				C	C	C	-/NA				
		5"	-	None	1-MS-RV-101A Relief/Air	-	No				C	C	C	-/FC				
'B' Main Steam Header	074	30"	3	None	1-MS-TV-101B Check/Air Pilot	-	No	No	No	SI or HH	O	C	C	-/FC	Out	Hot	Steam	7
					1-MS-116 Gate/Manual	-	No				C	C	C	-/NA				
		4"	-	None	1-MS-120 Gate/Manual	-	No				O	O	O	-/NA				6
					1-MS-378 Gate/Manual	-	No				C	C	C	-/NA				
		3"	-	None	1-MS-NRV-102B Stop Check/Manual	-	No				C	C	C	-/NA				
		2"	-	None	1-GN-2 Gate/Manual	-	No				C	C	C	-/NA				
		1-1/2”	-	None	1-MS-268 Gate Manual	-	No				C	C	C	-/NA				
		4"	-	None	1-MS-SV-101B Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-102B Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-103B Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-104B Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-105B Safety	-	No				C	C	C	-/NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
		5"	-	None	1-MS-RV-101B Relief/Air	-	No				C	C	C	-/FC				
'C' Main Steam Header	075	30"	3	None	1-MS-TV-101C Check/Air Pilot	-	No	No	No	SI or HH	O	C	C	-/FC	Out	Hot	Steam	7
					1-MS-155 Gate/Manual	-	No				C	C	C	-/NA				
		4"	-	None	1-MS-158 Gate/Manual	-	No				O	O	O	-/NA				6
					1-MS-377 Gate/Manual	-	No				C	C	C	-/NA				
		3"	-	None	1-MS-NRV-102C Stop Check/Manual	-	No				C	C	C	-/NA				
		2"	-	None	1-GN-3 Gate/Manual	-	No				C	C	C	-/NA				
		1-1/2"	-	None	1-MS-208 Gate Manual	-	No				C	C	C	-/NA				
		4"	-	None	1-MS-SV-101C Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-102C Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-103C Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-104C Safety	-	No				C	C	C	-/NA				
		6"	-	None	1-MS-SV-105C Safety	-	No				C	C	C	-/NA				
		5"	-	None	1-MS-RV-101C Relief/Air	-	No				C	C	C	-/FC				
'A' Feedwater Header	076	14"	3	1-FW-10 Check	1-FW-12 Check	No	No	No	No	-	O	C	O	NA/NA	In	Hot	Liquid	7

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)

UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]: Normal	Line Status[c, d]: Shut-down	Line Status[c, d]: Incident	Line Status[c, d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
'C' Feedwater Header	077	14"	3	1-FW-72 Check	1-FW-74 Check	No	No	No	No	-	O	C	O	NA/NA	In	Hot	Liquid	7
'B' Feedwater Header	078	14"	3	1-FW-41 Check	1-FW-43 Check	No	No	No	No	-	O	C	O	NA/NA	In	Hot	Liquid	7
SW to 'D' RS HX	079	24"	3	None	1-SW-MOV-104D Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW to 'C' RS HX	080	24"	3	None	1-SW-MOV-104C Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW to 'B' RS HX	081	24"	3	None	1-SW-MOV-104B Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW to 'A' RS HX	082	24"	3	None	1-SW-MOV-104A Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW from 'D' RS HX	083	24"	3	None	1-SW-MOV-105D Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
SW from 'C' RS HX	084	24"	3	None	1-SW-MOV-105C Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
SW from 'B' RS HX	085	24"	3	None	1-SW-MOV-105B Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
SW from 'A' RS HX	086	24"	3	None	1-SW-MOV-105A Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
AFW to FW	087	6"	3	1-FW-131 Check	1-FW-133 Check	No	No	2	Yes	-	C	C	O	NA/NA	In	Cold	Liquid	7
AFW to FW	088	6"	3	1-FW-136 Check	1-FW-138 Check	No	No	2	Yes	-	C	C	O	NA/NA	In	Cold	Liquid	7
Condenser Air Ejector Discharge	089	6"	1	1-VP-12 Check	1-SV-TV-102A Gate/Air Pilot	Yes	Yes	No	-	SI	O	O	C	NA/FC	In	Cold	Gas	
Containment Purge Exhaust Ventilation System	090	36"	5	1-VS-MOV-100C Butterfly/Motor	1-VS-MOV-101 Butterfly/Motor	Yes	Yes	No	-	-	LC	O	LC	FAI/FAI	Out	Cold	Gas	4, 10

a. See Note 9

b. Cold < 250°F; Hot > 250°F

c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed

d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable

e. I/O = Inside/Outside

f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
					1-VS-MOV-100D Butterfly/Motor	-	Yes				LC	O	LC	-/FAI				
Containment Purge Supply Ventilation System	091	36"	5	1-VS-MOV-100A Butterfly/Motor	1-VS-MOV-100B Butterfly/Motor	Yes	Yes	No	-	-	LC	O	LC	FAI/FAI	In	Cold	Gas	4, 10
					1-VS-MOV-102 Butterfly/Motor	-	Yes				LC	O	LC	-/FAI				
Containment Vacuum 'A' Pump Suction and Gaseous Waste Hydrogen Analyzer	092	2"	1	None	1-CV-TV-150C Globe/Air Pilot	-	Yes	1	No	SI	INT	C	C	-/FC	Out	Cold	Gas	
		3/8"	1	None	1-CV-TV-150D Globe/Air Pilot	-	Yes			SI	INT	C	C	-/FC				
					1-GW-TV-100 Plug/Air Pilot	-	Yes	No		-	C	C	O	-/FC				
					1-GW-TV-101 Plug/Air Pilot	-	Yes			-	C	C	O	-/FC				
Containment Vacuum 'B' Pump Suction and Gaseous Waste Hydrogen Analyzer	093	2"	1	None	1-CV-TV-150A Globe/Air Pilot	-	Yes	1	No	SI	INT	C	C	-/FC	Out	Cold	Gas	
		3/8"	1	None	1-CV-TV-150B Globe/Air Pilot	-	Yes			SI	INT	C	C	-/FC				
					1-GW-TV-104 Plug/Air Pilot	-	Yes	No		-	C	C	O	-/FC				
					1-GW-TV-105 Plug/Air Pilot	-	Yes			-	C	C	O	-/FC				
Containment Vacuum & Leakage Monitoring	094	8"	5	1-CV-HCV-100 Globe/Air Pilot	1-CV-2 Gate/Manual	Yes	Yes	No	No	-	LC	INT	LC	FC/NA	Out	Cold	Gas	4
'A' SG Recirc & Transfer	096	3"	3	1-RT-2 Ball/Manual	1-RT-6 Ball/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	Out	Cold	Liquid	4, 11

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]: Normal	Line Status[c, d]: Shut-down	Line Status[c, d]: Incident	Line Status[c, d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
‘B’ SG Recirc & Transfer	022	3"	3	1-RT-21 Ball/Manual	1-RT-25 Ball/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	Out	Cold	Liquid	4, 11
‘C’ SG Recirc & Transfer	114	3"	3	1-RT-40 Ball/Manual	1-RT-44 Ball/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	Out	Cold	Liquid	4, 11
RHR Sample	097B	3/8”	1	1-SS-TV-103A Globe/Air Pilot	1-SS-TV-103B Globe/Air Pilot	Yes	Yes	1	No	SI	C	INT	C	FC/FC	Out	Cold	Liquid	
Leakage Monitoring	097C	3/8”	1	None	1-LM-TV-100A Globe/Air Pilot	-	Yes	1	No	SI	C	C	C	-/FC	Out	Cold	Gas	4
					1-LM-TV-100B Globe/Air Pilot	-	Yes							/FC				
Gaseous Waste	100	3/8” valve, 3" penetration	1	None	1-GW-TV-102 Globe/Air Pilot	-	Yes	1	No	-	C	C	C	-/FC	In	Cold	Gas	
					1-GW-TV-103 Globe/Air Pilot	-	Yes							/FC				
Fire Protection	101	4"	5	None	1-FP-151 Ball/Manual	-	Yes	No	No	-	LC	INT	LC	NA	In	Cold	Liquid	4
					1-FP-152 Ball/Manual	-	Yes							NA				
Unit 2 - AFW Cross Connect	102	6"	3	1-FW-273 Check	1-FW-272 Check	No	No	2	Yes	-	C	C	O/INT	NA	In	Cold	Liquid	7
Reactor Cavity Purification Inlet	103	3"	5	1-RL-5 Diaphragm/Manual	1-RL-3 Diaphragm/Manual	Yes	Yes	No	No	-	LC	O/INT	LC	NA	In	Cold	Liquid	4, 10
Reactor Cavity Purification Outlet	104	3"	5	1-RL-13 Diaphragm/Manual	1-RL-15 Diaphragm/Manual	Yes	Yes	No	No	-	LC	O/INT	LC	NA	Out	Cold	Liquid	4
Hydrogen Sample	105C	3/8”	1	1-GW-TV-111A Globe/Air Pilot	1-GW-TV-111B Globe/Air Pilot	Yes	Yes	1	No	-	C	C	O/INT	FC/FC	Out	Cold	Gas	
Leakage Monitoring	105D	3/8”	1	None	1-LM-TV-100C Globe/Air Pilot	-	Yes	1	No	SI	C	C	C	-/FC	Out	Cold	Gas	4

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-1 (CONTINUED)
UNIT 1 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c, d]: Normal	Line Status[c, d]: Shut-down	Line Status[c, d]: Incident	Line Status[c, d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
					1-LM-TV-100D Globe/Air Pilot	-	Yes							-/FC				
SI Test Line	106	3/4”	5	1-SI-HCV-1850A Globe/Air Pilot	1-SI-73 Globe/Manual	No	Yes	No	No	-	C/LC	LC	LC	FC/NA	Out	Cold	Liquid	3, 4
				1-SI-HCV-1850B Globe/Air Pilot		No	-							FC/-				
				1-SI-HCV-1850C Globe/Air Pilot		No	-							FC/-				
				1-SI-HCV-1850D Globe/Air Pilot		No	-							FC/-				
				1-SI-HCV-1850E Globe/Air Pilot		No	-							FC/-				
				1-SI-HCV-1850F Globe/Air Pilot		No	-							FC/-				
CCW from RCP Thermal Barrier	110	3"	3	1-CC-TV-140A Globe/Air Pilot	1-CC-TV-140B Globe/Air Pilot	No	No	2	No	HH	O	O	C	FC/FC	Out	Cold	Liquid	1
Containment Instrument Air	112	3"	1	1-IA-TV-101A Plug/Air Pilot	1-IA-TV-101B Plug/Air Pilot	Yes	Yes	1	No	H	O	O	C	FC/FC	Out	Cold	Gas	
Safety Injection	113	3"	4	1-SI-227 Check	1-SI-MOV-1869A Gate/Motor	No	No[a]	1	Yes	-	C	C	O/INT	NA/FAI	In	Cold	Liquid	2, 4, 9
					1-SI-174 Globe/Manual	-	No[a]				LC	LC	LC	-/NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status [c,d]: Normal	Line Status [c,d]: Shut-down	Line Status [c,d]: Incident	Line Status [c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
CCW from 'B' RHR HX	001	18"	3	None	2-CC-TV-209B Butterfly/Air Pilot	-	No	2	No	SI	-	-	C	-/FC	Out	Cold	Liquid	1
CCW to 'A' RHR HX	002	18"	3	2-CC-177 Check	2-CC-214 Butterfly/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to 'B' RHR HX	004	18"	3	2-CC-176 Check	2-CC-220 Butterfly/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW from 'A' RHR HX	005	18"	3	None	2- CC-TV-209A Butterfly/Air Pilot	-	No	2	No	SI	-	-	C	NA/FC	Out	Cold	Liquid	1
High Head SI (Normal header)	007	3"	4	2-SI-225 Check	2-SI-150 Globe/Manual	No	No[a]	1	Yes	SI	LC	LC	LC	NA/LC	In	Cold	Liquid	2, 4, 9
					2-SI-MOV-2867D Gate/Motor	-	No[a]				C	C	O	-/FAI				
					2-SI-MOV-2867C Gate/Motor	-	No[a]				C	C	O	-/FAI				1
CCW to 'C' Air Recirc. Fan	009	6"	3	2-CC-224 Check	2-CC-223 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to 'A' Air Recirc. Fan	010	6"	3	2-CC-242 Check	2-CC-241 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to 'B' Air Recirc. Fan	011	6"	3	2-CC-233 Check	2-CC-232 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW from 'B' Air Recirc. Fan	012	6"	3	None	2-CC-TV-210B Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from 'C' Air Recirc. Fan	013	6"	3	None	2-CC-TV-210C Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from 'A' Air Recirc Fan	014	6"	3	None	2-CC-TV-210A Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
Chemical and Volume Control	015	3"	2	2-CH-309 Check	2-CH-MOV-2289A Gate/Motor	No	No[a]	No	No	SI	O	O	C	NA/FAI	In	Cold	Liquid	9

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
CCW to ‘C’ RCP	016	6"	3	2-CC-59 Check	2-CC-216 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to ‘B’ RCP	017	6"	3	2-CC-58 Check	2-CC-218 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
CCW to ‘A’ RCP	018	6"	3	2-CC-1 Check	2-CC-219 Gate/Manual	No	No	2	No	-	O	O	C	NA	In	Cold	Liquid	1
Seal Water from RCPs	019	3"	2	None	2-CH-MOV-2381 Gate/Motor	-	Yes	No	No	SI	O	O	C	-/FAI	Out	Cold	Liquid	
Safety Injection Accumulator Makeup	020	1"	5	2-SI-HCV-2851A Globe/Air Pilot	2-SI-32 Globe/Manual	No	Yes	No	-	-	LC	LC	LC	FC/NA	In	Cold	Liquid	3, 4
				2-SI-HCV-2851B Globe/Air Pilot		No	-							FC/-				
				2-SI-HCV-2851C Globe/Air Pilot		No	-							FC/-				
High Head Safety Injection to Cold Leg (Alternate header)	021	3"	4	2-SI-224 Check	2-SI-MOV-2842 Gate/Motor	No	No[a]	1	Yes	-	C	C	INT	NA/FAI	In	Cold	Liquid	2, 9
High Head Safety Injection to Hot Leg	023	3"	4	2-SI-226 Check	2-SI-MOV-2869B Gate/Motor	No	No[a]	1	Yes	-	C	C	INT	NA/FAI	In	Cold	Liquid	2, 9
RHR to RWST	024	6"	5	2-RH-29 Gate/Manual	2-RH-108 Gate/Manual	No	Yes	No	No	-	LC	INT	LC	NA/FAI	Out	Cold	Liquid	3, 4
CCW from ‘A’ RCP	025	6"	3	None	2-CC-TV-205A Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from ‘C’ RCP	026	6"	3	None	2-CC-TV-205C Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
CCW from ‘B’ RCP	027	6"	3	None	2-CC-TV-205B Plug/Air Pilot	-	No	2	No	HH	O	O	C	-/FC	Out	Cold	Liquid	1
Reactor Coolant Letdown	028	2"	2	2-CH-TV-2204A Globe/Air Pilot	2-CH-TV-2204B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Hot	Liquid	

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
Gaseous Waste	032	3/8" valve, 3" penetration	1	None	2-GW-TV-202 Globe/Air Pilot	-	Yes	No	No	-	C	C	C	-/FC	In	Cold	Gas	
					2-GW-TV-203 Globe/Air Pilot	-	Yes											
Primary Drain Transfer Tank Pump Discharge	033	2"	1	2-DG-TV-208A Globe/Air Pilot	2-DG-TV-208B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Cold	Liquid	
Seal Water to 'C' RCP	035	2"	4	2-CH-349 Check	2-CH-300 Needle/Manual	No	No	1	No	-	O	O	O	NA	In	Cold	Liquid	2, 5
Seal Water to 'A' RCP	036	2"	4	2-CH-323 Check	2-CH-294 Needle/Manual	No	No	1	No	-	O	O	O	NA	In	Cold	Liquid	2, 5
Seal Water to 'B' RCP	037	2"	4	2-CH-333 Check	2-CH-297 Needle/Manual	No	No	1	No	-	O	O	O	NA	In	Cold	Liquid	2, 5
Aerated Drain Sump Pump Discharge	038	2"	1	2-DA-TV-200A Ball/Air Pilot	2-DA-TV-200B Ball/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Cold	Liquid	
SG Blowdown-1A	039	3"	3	2-BD-TV-200A Gate/Air Pilot	2-BD-TV-200B Gate/Air Pilot	No	No	No	No	AFW	O	O	C	FC/FC	Out	Hot	Liquid	7
SG Blowdown-1C	040	3"	3	2-BD-TV-200E Gate/Air Pilot	2-BD-TV-200F Gate/Air Pilot	No	No	No	No	AFW	O	O	C	FC/FC	Out	Hot	Liquid	7
SG Blowdown-1B	041	3"	3	2-BD-TV-200C Gate/Air Pilot	2-BD-TV-200D Gate/Air Pilot	No	No	No	No	AFW	O	O	C	FC/FC	Out	Hot	Liquid	7
Service Air Supply	042	2"	5	None	2-SA-82 Gate/Manual	-	Yes	No	No	-	LC	INT	LC	NA	In	Cold	Gas	4
					2-SA-81 Gate Manual	-	Yes											
Particulate and Gaseous Rad Monitoring Return	043	1"	1	2-RM-3 Check	2-RM-TV-200A Globe/Air Pilot	Yes	Yes	No	No	H	O	O	C	NA/FC	In	Cold	Gas	

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
Particulate and Gaseous Rad Monitoring Supply	044	1"	1	2-RM-TV-200C Globe/Air Pilot	2-RM-TV-200B Globe/Air Pilot	Yes	Yes	No	No	H	O	O	C	FC/FC	Out	Cold	Gas	
Primary Grade Water to PRT	045	3"	1	2-RC-160 Check	2-RC-TV-2519A Diaphragm/Air Pilot	Yes	Yes	No	No	SI	INT	C	C	NA/FC	In	Cold	Liquid	
Loop Fill Header	046	2"	5	2-RC-HCV-2556A Globe/Air Pilot	2-CH-FCV-2160 Globe/Air Pilot	No	No[a]	No	No	-	C	INT	C	FC/FC	In	Cold	Liquid	3, 9
				2-RC-HCV-2556B Globe/Air Pilot		No	-							FC/				
				2-RC-HCV-2556C Globe/Air Pilot		No	-							FC/				
Instrument Air Supply	047	2"	1	2-IA-864 Check	2-IA-TV-200 Globe/Air Pilot	Yes	Yes	No	No	HH	O	O	C	NA/FC	In	Cold	Gas	4
					2-IA-704 Gate/Manual	-	Yes				INT/LC	O	INT/LC	-/NA				
Primary Vent Header	048	2"	1	2-VG-TV-209A Globe/Air Pilot	2-VG-TV-209B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O	C	FC/FC	Out	Cold	Gas	
Accumulator Vent Header to Gaseous Waste	050	1"	1	2-SI-TV-201A Globe/Air Pilot	2-SI-TV-201B Globe/Air Pilot	Yes	Yes	No	No	SI	O	O/INT	C	FC/FC	Out	Cold	Gas	
Recirc Spray HX SW Drains	051	2"	5	2-SW-206 Gate/Manual	2-SW-208 Gate/Manual	Yes	Yes	No	No	-	LC	INT	LC	NA	Out	Cold	Liquid	4
Nitrogen to PRT	053	1"	2	2-SI-304 Check	2-SI-TV-200 Globe/Air Pilot	Yes	Yes	No	No	SI	INT	C	C	NA/FC	In	Cold	Gas	
Primary Vent Pot Vent	054	2"	5	2-VA-9 Gate/Manual	2-VA-1 Gate/Manual	Yes	Yes	No	No	-	LC	O/INT	LC	NA	Out	Cold	Gas	4
Leakage Monitoring	055D	3/8”	1	None	2-LM-TV-200G Globe/Air Pilot	-	Yes	No	No	SI	C	C	C	-/FC	Out	Cold	Gas	4
					2-LM-TV-200H Globe/Air Pilot	-	Yes											

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
RCS Hot Leg Sample	056A	3/8”	1	2-SS-TV-206A Globe/Air Pilot	2-SS-TV-206B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	-/FC	Out	Cold	Liquid	
RCS Cold Leg Sample	056B	3/8”	1	2-SS-TV-202A Globe/Air Pilot	2-SS-TV-202B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Liquid	
Pressurizer Liquid Sample	056D	3/8”	1	2-SS-TV-200A Globe/Air Pilot	2-SS-TV-200B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Liquid	
Pressurizer Steam Space Sample	057A	3/8”	1	2-SS-TV-201A Globe/Air Pilot	2-SS-TV-201B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Gas	
Post Accident Sample Return	057B	2"	1	None	2-DA-TV-203B Globe/Air Pilot	-	Yes	No	No	SI	INT	INT	C	-/FC	In	Cold	Liquid	
					2-DA-TV-203A Globe/Air Pilot	-	Yes							-/FC				
Leakage Monitoring	057C	3/8”	1	None	2-LM-TV-200F Globe/Air Pilot	-	Yes	No	No	SI	INT	INT	C	-/FC	Out	Cold	Gas	4
					2-LM-TV-200E Globe/Air Pilot	-	Yes							-/FC				
PRT Sample	057D	3/8”	1	2-SS-TV-204A Globe/Air Pilot	2-SS-TV-204B Globe/Air Pilot	Yes	Yes	No	No	SI	INT	INT	C	FC/FC	Out	Cold	Gas	
Instrument Air from Unit 1	058	2"	5	2-IA-868 Check	1-IA-704 Gate/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	In	Cold	Gas	4
‘A’ Low Head SI Pump Discharge to Hot Legs	060	6"	4	2-SI-229 Check	2-SI-MOV-2890A Gate/Motor	No	No[a]	1	Yes	-	C	C	C/INT	NA/FAI	In	Cold	Liquid	2, 9
		3"	5	2-SI-500/Globe	Valve/Manual	No	No[a]	1	Yes	-	C	C	C	NA/FAI	In	Cold	Liquid	2, 4, 9
Low Head SI Pumps Discharge to Cold Legs	061	6"	4	2-SI-243 Check	2-SI-MOV-2890C Gate/Motor	No	No[a]	1	Yes	-	O	-	O	NA/FAI	In	Cold	Liquid	2, 6, 9
				2-SI-242 Check		No	-							NA/				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
				2-SI-241 Check		No	-							NA/				
'B' Low Head SI Pump Discharge to Hot Legs	062	6"	4	2-SI-228 Check	2-SI-MOV-2890B Gate/Motor	No	No[a]	1	Yes	-	C	C	C/INT	NA/FAI	In	Cold	Liquid	2, 9
'B' CS Pump Discharge to Spray Ring	063	8"	4	2-CS-24 Check	2-CS-MOV-201C Butterfly/Motor	Yes	Yes	1	Yes	HH	C	C	O	NA/FAI	In	Cold	Liquid	
					2-CS-MOV-201D Butterfly/Motor	-	Yes							NA/FAI				
'A' CS Pump Discharge to Spray Ring	064	8"	4	2-CS-13 Check	2-CS-MOV-201A Butterfly/Motor	Yes	Yes	1	Yes	HH	C	C	O	NA/FAI	In	Cold	Liquid	
					2-CS-MOV-201B Butterfly/Motor	-	Yes							NA/FAI				
'A' ORS Pump Suction from Containment Sump	066	12"	4	None	2-RS-MOV-255A Plug/Motor	-	No[a]	1	Yes	HH	O	O	O	-/FAI	Out	Cold	Liquid	4, 9
					2-RS-53 Gate/Manual	-	No[a]				LC	LC	LC	NA				
'B' ORS Pump Suction from Containment Sump	067	12"	4	None	2-RS-MOV-255B Plug/Motor	-	No[a]	1	Yes	HH	O	O	O	-/FAI	Out	Cold	Liquid	4, 9
					2-RS-46 Gate/Manual	-	No[a]				LC	LC	LC	NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status [c,d]: Normal	Line Status: Shut-down	Line Status: Incident	Line Status: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
‘B’ Low Head SI Suction from Containment Sump	068	12"	4	None	2-SI-MOV-2860B Gate/Motor	-	No[a]	1	Yes	-	C	C	INT	-/FAI	Out	Cold	Liquid	4, 9
					2-SI-321 Gate/Manual	-	No[a]				LC	LC	LC	NA				
‘A’ Low Head SI Suction from Containment Sump	069	12"	4	None	2-SI-MOV-2860A Gate/Motor	-	No[a]	1	Yes	-	C	C	INT	-/FAI	Out	Cold	Liquid	4, 9
					2-SI-322 Gate/Manual	-	No[a]				LC	LC	LC	NA				
‘B’ ‘ORS Pump Discharge to Spray Ring	070	10"	4	2-RS-11 Check	2-RS-MOV-256B Butterfly/Motor	Yes	Yes	1	Yes	HH	O	O	O	NA/FAI	In	Cold	Liquid	
‘A’ ORS Pump Discharge to Spray Ring	071	10"	4	2-RS-017 Check	2-RS-MOV-256A Butterfly/Motor	Yes	Yes	1	Yes	HH	O	O	O	NA/FAI	In	Cold	Liquid	
‘A’ Main Steam Header	073	30"	3	None	2-MS-TV-201A Check/Air Pilot	-	No	No	No	SI or HH	O	C	C	-/FC	Out	Hot	Steam	7
					2-MS-84 Gate/Manual	-	No				C	C	C	-/NA				
		4"	-	None	2-MS-87 Gate/Manual	-	No				O	O	O	-/NA				6
					2-MS-379 Gate/Manual	-	No				C	C	C	-/NA				
		3"	-	None	2-MS-NRV-202A Stop Check/Manual	-	No				C	C	C	-/NA				
		2"	-	None	2-GN-1 Gate Manual	-	No				C	C	C	-/NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
		1-1/2”	-	None	2-MS-266 Gate Manual	-	No				C	C	C	-/NA				
		4"	-	None	2-MS-SV-201A Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-202A Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-203A Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-204A Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-205A Safety	-	No				C	C	C	-/NA				
		5"	-	None	2-MS-RV-201A Relief/Air	-	No				C	C	C	-/FC				
‘C’ Main Steam Header	074	30"	3	None	2-MS-TV-201C Check/Air Pilot	-	No	No	No	SI or HH	O	C	C	-/FC	Out	Hot	Steam	7
					2-MS-155 Gate/Manual	-	No				C	C	C	-/NA				
		4"	-	None	2-MS-158 Gate/Manual	-	No				O	O	O	-/NA				6
					2-MS-377 Gate/Manual	-	No				C	C	C	-/NA				
		3"	-	None	2-MS-NRV-202C Stop Check/Manual	-	No				C	C	C	-/NA				
		2"	-	None	2-GN-3 Gate/Manual	-	No				C	C	C	-/NA				
		1-1/2”	-	None	2-MS-208 Gate Manual	-	No				C	C	C	-/NA				
		4"	-	None	2-MS-SV-201C Safety	-	No				C	C	C	-/NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
		6"	-	None	2-MS-SV-202C Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-203C Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-204C Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-205C Safety	-	No				C	C	C	-/NA				
		5"	-	None	2-MS-RV-201C Relief/Air	-	No				C	C	C	-/FC				
'B' Main Steam Header	075	30"	3	None	2-MS-TV-201B Check/Air Pilot	-	No	No	No	SI or HH	O	C	C	-/FC	Out	Hot	Steam	7
					2-MS-116 Gate/Manual	-	No				C	C	C	-/NA				
		4"	-	None	2-MS-120 Gate/Manual	-	No				O	O	O	-/NA				6
					2-MS-378 Gate/Manual	-	No				C	C	C	-/NA				
		3"	-	None	2-MS-NRV-202B Stop Check/Manual	-	No				C	C	C	-/NA				
		2"	-	None	2-GN-2 Gate/Manual	-	No				C	C	C	-/NA				
		1-1/2"	-	None	2-MS-268 Gate Manual	-	No				C	C	C	-/NA				
		4"	-	None	2-MS-SV-201B Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-202B Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-203B Safety	-	No				C	C	C	-/NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)

UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator Inside	Outside	10 CFR 50 Appendix J Test Required Inside	Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d] Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
		6"	-	None	2-MS-SV-204B Safety	-	No				C	C	C	-/NA				
		6"	-	None	2-MS-SV-205B Safety	-	No				C	C	C	-/NA				
		5"	-	None	2-MS-RV-201B Relief/Air	-	No				C	C	C	-/FC				
'C' Feedwater Header	076	14"	3	2-FW-72 Check	2-FW-74 Check	No	No	No	No	-	O	C	O	NA/NA	In	Hot	Liquid	7
'B' Feedwater Header	077	14"	3	2-FW-41 Check	2-FW-43 Check	No	No	No	No	-	O	C	O	NA/NA	In	Hot	Liquid	7
'A' Feedwater Header	078	14"	3	2-FW-10 Check	2-FW-12 Check	No	No	No	No	-	O	C	O	NA/NA	In	Hot	Liquid	7
SW to 'D' RS HX	079	24"	3	None	2-SW-MOV-204D Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW to 'C' RS HX	080	24"	3	None	2-SW-MOV-204C Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW to 'B' RS HX	081	24"	3	None	2-SW-MOV-204B Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW to 'A' RS HX	082	24"	3	None	2-SW-MOV-204A Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	In	Cold	Liquid	8
SW from 'D' RS HX	083	24"	3	None	2-SW-MOV-205D Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
SW from 'C' RS HX	084	24"	3	None	2-SW-MOV-205C Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
SW from 'B' RS HX	085	24"	3	None	2-SW-MOV-205B Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
SW from 'A' RS HX	086	24"	3	None	2-SW-MOV-205A Butterfly/Motor	-	No	1	Yes	HH	C	C	O	-/FAI	Out	Cold	Liquid	8
AFW to FW	087	6"	3	2-FW-131 Check	2-FW-133 Check	No	No	2	Yes	-	C	C	O	NA/NA	In	Cold	Liquid	7
AFW to FW	088	6"	3	2-FW-136 Check	2-FW-138 Check	No	No	2	Yes	-	C	C	O	NA/NA	In	Cold	Liquid	7

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator: Inside	Penetration Configuration Valve Number/Type/Operator: Outside	10 CFR 50 Appendix J Test Required: Inside	10 CFR 50 Appendix J Test Required: Outside	Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status[c,d]: Normal	Line Status[c,d]: Shut-down	Line Status[c,d]: Incident	Line Status[c,d]: Loss of Pwr (I/O)[e]	Flow	Temperature[b]	Fluid	Notes
Condenser Air Ejector Discharge	089	6"	1	2-VP-12 Check	2-SV-TV-202A Gate/Air Pilot	Yes	Yes	No	-	SI	O	O	C	NA/FC	In	Cold	Gas	
Containment Purge Exhaust Ventilation System	090	36"	5	2-VS-MOV-200C Butterfly/Motor	2-VS-MOV-201 Butterfly/Motor	Yes	Yes	No	-	-	LC	O	LC	FAI/FAI	Out	Cold	Gas	4, 10
					2-VS-MOV-200D Butterfly/Motor	-	Yes				LC	O	LC	-/FAI				
Containment Purge Supply Ventilation System	091	36"	5	2-VS-MOV-200A Butterfly/Motor	2-VS-MOV-200B Butterfly/Motor	Yes	Yes	No	-	-	LC	O	LC	FAI/FAI	In	Cold	Gas	4, 10
					2-VS-MOV-202 Butterfly/Motor	-	Yes				LC	O	LC	-/FAI				
Containment Vacuum 'A' Pump Suction and Gaseous Waste Hydrogen Analyzer	092	2"	1	None	2-CV-TV-250C Globe/Air Pilot	-	Yes	1	No	SI	INT	C	C	-/FC	Out	Cold	Gas	
		3/8"	1	None	2-CV-TV-250D Globe/Air Pilot	-	Yes			SI	INT	C	C	-/FC				
					2-GW-TV-204 Plug/Air Pilot	-	Yes	No		-	C	C	O	-/FC				
					2-GW-TV-205 Plug/Air Pilot	-	Yes			-	C	C	O	-/FC				
Containment Vacuum 'B' Pump Suction and Gaseous Waste Hydrogen Analyzer	093	2"	1	None	2-CV-TV-250A Globe/Air Pilot	-	Yes	1	No	SI	INT	C	C	-/FC	Out	Cold	Gas	
		3/8"	1	None	2-CV-TV-250B Globe/Air Pilot	-	Yes			SI	INT	C	C	-/FC				
					2-GW-TV-200 Plug/Air Pilot	-	Yes	No		-	C	C	O	-/FC				
					2-GW-TV-201 Plug/Air Pilot	-	Yes			-	C	C	O	-/FC				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status [c,d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
Containment Vacuum & Leakage Monitoring	094	8"	5	2-CV-HCV-200 Globe/Air Pilot	2-CV-2 Gate/Manual	Yes	Yes	No	No	-	LC	INT	LC	FC/NA	Out	Cold	Gas	4
'A' SG Recirc & Transfer	096	3"	3	2-RT-2 Ball/Manual	2-RT-6 Ball/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	Out	Cold	Liquid	4, 11
'B' SG Recirc & Transfer	022	3"	3	2-RT-21 Ball/Manual	2-RT-25 Ball/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	Out	Cold	Liquid	4, 11
'C' SG Recirc & Transfer	114	3"	3	2-RT-40 Ball/Manual	2-RT-44 Ball/Manual	Yes	Yes	No	No	-	LC	O	LC	NA	Out	Cold	Liquid	4, 11
RHR Sample	097B	3/8"	1	2-SS-TV-203A Globe/Air Pilot	2-SS-TV-203B Globe/Air Pilot	Yes	Yes	1	No	SI	C	INT	C	FC/FC	Out	Cold	Liquid	
Leakage Monitoring	097C	3/8"	1	None	2-LM-TV-200A Globe/Air Pilot	-	Yes	1	No	SI	C	C	C	-/FC	Out	Cold	Gas	4
					2-LM-TV-200B Globe/Air Pilot	-	Yes							-/FC				
Gaseous Waste	100	3/8" valve, 3" penetration	1	None	2-GW-TV-206 Globe/Air Pilot	-	Yes	1	No	-	C	C	C	-/FC	In	Cold	Gas	
					2-GW-TV-207 Globe/Air Pilot	-	Yes							-/FC				
Fire Protection	101	4"	5	None	2-FP-151 Ball/Manual	-	Yes	No	No	-	LC	INT	LC	NA	In	Cold	Liquid	4
					2-FP-152 Ball/Manual	-	Yes							NA				
Unit 1- AFW Cross Connect	102	6"	3	2-FW-273 Check	2-FW-272 Check	No	No	2	Yes	-	C	C	O/INT	NA	In	Cold	Liquid	7
Reactor Cavity Purification Inlet	103	3"	5	2-RL-5 Diaphragm/Manual	2-RL-3 Diaphragm/Manual	Yes	Yes	No	No	-	LC	O/INT	LC	NA	In	Cold	Liquid	4, 10
Reactor Cavity Purification Outlet	104	3"	5	2-RL-13 Diaphragm/Manual	2-RL-15 Diaphragm/Manual	Yes	Yes	No	No	-	LC	O/INT	LC	NA	Out	Cold	Liquid	4

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Table 5.2-2 (CONTINUED)
UNIT 2 CONTAINMENT PENETRATIONS

System Name	Pen No.	Nominal Line Size	Line Class Per UFSAR	Penetration Configuration Valve Number/Type/Operator		10 CFR 50 Appendix J Test Required		Essential System Level 1, 2, or No	ESF System	Actuation Signal[f]	Line Status [c,d]				Flow	Temperature[b]	Fluid	Notes
				Inside	Outside	Inside	Outside				Normal	Shut-down	Incident	Loss of Pwr (I/O)[e]				
Leakage Monitoring	105B	3/8”	1	None	2-LM-TV-200C Globe/Air Pilot	-	Yes	1	No	SI	C	C	C	-/FC	Out	Cold	Gas	4
					2-LM-TV-200D Globe/Air Pilot	-	Yes							-/FC				
Hydrogen Sample	105C	3/8”	1	2-GW-TV-211A Globe/Air Pilot	2-GW-TV-211B Globe/Air Pilot	Yes	Yes	1	No	-	C	C	O/INT	FC/FC	Out	Cold	Gas	
SI Test Line	106	3/4”	5	2-SI-HCV-2850A Globe/Air Pilot	2-SI-73 Globe/Manual	No	Yes	No	No	-	C/LC	LC	LC	FC/NA	Out	Cold	Liquid	3, 4
				2-SI-HCV-2850B Globe/Air Pilot		No	-							FC/-				
				2-SI-HCV-2850C Globe/Air Pilot		No	-							FC/-				
				2-SI-HCV-2850D Globe/Air Pilot		No	-							FC/-				
				2-SI-HCV-2850E Globe/Air Pilot		No	-							FC/-				
				2-SI--HCV-2850F Globe/Air Pilot		No	-							FC/-				
CCW from RCP Thermal Barrier	110	3"	3	2-CC-TV-240A Globe/Air Pilot	2-CC-TV-240B Globe/Air Pilot	No	No	2	No	HH	O	O	C	FC/FC	Out	Cold	Liquid	1
Containment Instrument Air	112	3"	1	2-IA-TV-201A Plug/Air Pilot	2-IA-TV-201B Plug/Air Pilot	Yes	Yes	1	No	H	O	O	C	FC/FC	Out	Cold	Gas	
Safety Injection	113	3"	4	2-SI-227 Check	2-SI-MOV-2869A Gate/Motor	No	No[a]	1	Yes	-	C	C	O/INT	NA/FAI	In	Cold	Liquid	2, 4, 9
					2-SI-174 Globe/Manual	-	No[a]				LC	LC	LC	-/NA				

a. See Note 9
b. Cold < 250°F; Hot > 250°F
c. O = Open; C = Closed; Int = Intermediate; LC = Locked Closed
d. FC = Fails Closed; FAI = Fails As Is; NA = Not Applicable
e. I/O = Inside/Outside
f. HH = Phase 3, H = Phase 2, SI = Phase 1

Tables 5.2-1 and 5.2-2 Notes

1. Component Cooling Containment Penetration Isolation:

   Penetration #'s: 1, 2, 4, 5, 9, 10, 11, 12, 13, 14, 16, 17, 18, 25, 26, 27, 110

   These penetrations are in closed systems. Containment penetration check valves and trip valves are leak tested, but the leakage is not included in the 10 CFR 50 App. J Type B and C total leakage. During the associated penetration check valve test, the containment penetration manual isolation valve is leak tested in the reverse direction. The valve is tested with system pressure on the upstream side and the downstream side vented.

   Reference: T. S. Amendment 72/73 dated September 29, 1981.

2. Safety Injection Inside Containment Penetration Isolation:

   Penetration #'s: 7, 21, 23, 35, 36, 37, 60, 61, 62, 113

   Inside containment penetration check valves are not Type C tested. A single valve is acceptable because the system is closed outside of containment and a single active failure does not prevent isolation.

   Penetration numbers 7 and 113 have locked closed outside containment isolation valves under administrative control.

3. General Design Criteria (GDC) Compliance:

   Penetration #'s: 20, 24, 46, 106

   Containment isolation for the above penetrations is consistent with the original design basis of the UFSAR for applicable class 5 lines. GDC 55 & 56 were not promulgated when these containment isolation configurations were designed. These penetrations are considered to meet the requirements of GDC 53 (July 1967). Type C testing is performed on the outside isolation valve only.

4. Locked Closed Containment Penetration Isolation Valves:

   The following Penetrations have either one or two Containment Penetration Isolation Manual Valves locked closed. These valves are maintained under administrative control. The valves outside containment are verified locked closed periodically. The valves inside containment are verified prior to exceeding Refueling shutdown conditions.

   Penetration #'s:

   <u>Outside/Inside Locked</u>: 22, 51, 54, 96, 103, 104, 114

   <u>Outside Locked</u>: 7, 20, 24, 42, 47, 55, 57, 58, 66, 67, 68, 69, 94, 97, 101, 105, 106, 113

The following penetrations have the containment penetration Isolation MOV Breaker locked open with the valve in the closed position. The containment isolation MOVs also have their handwheel locked. The valves and breakers are verified locked closed periodically.

Penetration #'s: 90, 91

5. Seal Water To RCP's:

   Penetration #'s: 35, 36, 37

   Needle valves are throttled open and administratively controlled. These lines remain open after a safety injection signal and contribute to the total injection flow while cooling the RCP seals. The incoming lines have a check valve inside containment and a local manual valve (throttle valve) outside containment combined with both a closed system and continuous water seal at a pressure sufficient to preclude containment atmospheric leakage.

6. Open Containment Penetration Isolation Valves:

   Penetration #'s: 61,74,75,76

   Penetration 61 has its breaker de-energized with the valve in the open position. This penetration is for Low Head Safety Injection Discharge to the Reactor Coolant System Cold Legs. The Safety Injection System outside containment has an external leakage Technical Specification requirement which provides limits to ensure acceptable leakage during accidents.

   Penetrations 74, 75, & 76 are the normal steam supply to the turbine driven auxiliary feedwater pump and are normally open. These valves are closed in accordance with emergency procedures to provide steam generator isolation in the event of a steam generator tube rupture.

7. Main Steam Containment Penetration Isolation:

   Penetration #'s: 39, 40, 41, 73, 74, 75, 76, 77, 78, 87, 88, 102

   No testing required - per App. J.

   These penetrations are in systems directly connected to the steam generator secondary side and, therefore, are considered a closed system (an extension of the primary containment). In addition, the steam generator remains at a pressure greater than peak accident pressure for at least the first hour and is not considered a credible leakage path from containment.

   Reference: T. S. Amendment 72/73 dated September 29, 1981.

   An air test is performed prior to a Type A Test. If a Type A Test is not performed, station procedures verify that no external leakage exists.

8. Service Water To Recirculation Spray Heat Exchanger Containment Penetration Isolation:

   Penetration #'s: 79, 80, 81, 82, 83, 84, 85, 86

These penetrations are in closed systems. Each train is leak tested but the leakage is not included in the 10 CFR 50 App. J Type B and C total leakage. The valves in these lines remain open during a design basis accident.

Reference: T. S. Amendment 72/73 dated September 29, 1981.

9. Water Filled Penetrations:

   Penetration #'s: 7, 15, 21, 23, 46, 60, 61, 62, 66, 67, 68, 69, 113

   These penetrations are in systems that are water filled and/or normally operating under accident conditions at a pressure greater than peak accident pressure. Therefore, these penetrations are not considered credible leakage paths from containment.

   Reference: NRC SER dated November 21, 1988.

10. Type C Reverse Direction Tests:

    Penetration #'s: 90, 91, 103

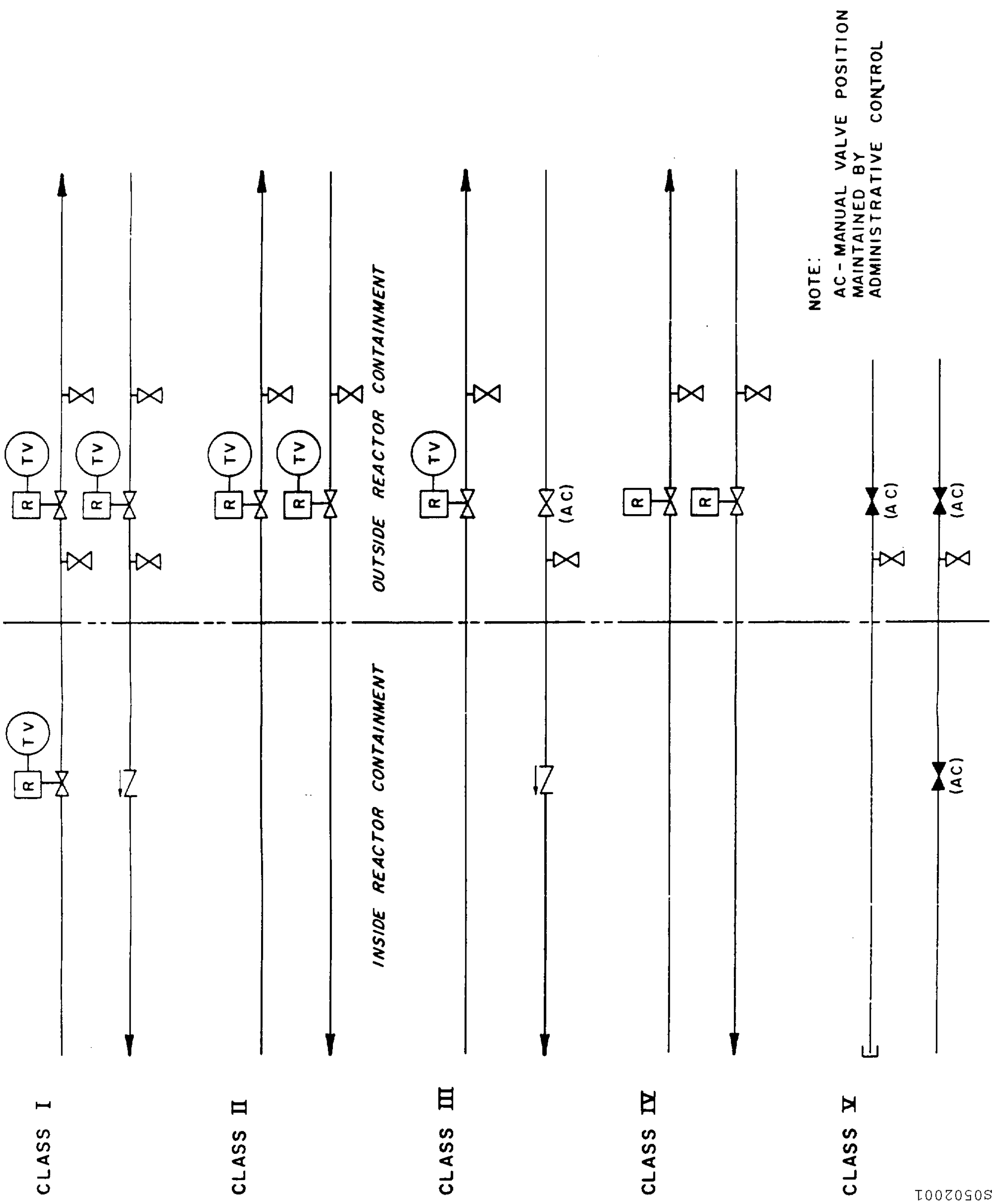
    Type C testing of the inboard isolation valve for penetration 90, 91, and 103 is performed in the reverse direction due to the existing piping configuration. For the type of inboard isolation valves used (diaphragm and butterfly), leakage is the same in either direction.

11. Steam Generator Recirc. And Transfer System:

    Penetration #'s: 22, 96, 114

    Due to the piping configuration inside containment, the above penetrations were added to the Type C testing program to ensure that any leakage through these valves is identified and corrected.

Figure 5.2-1
EXAMPLE OF VALVE ARRANGEMENT CONTAINMENT ISOLATION SYSTEM



5.3 CONTAINMENT SYSTEMS

5.3.1 Ventilation Systems

5.3.1.1 General Description

Containment ventilation consists of an air cooling recirculation system, an air cooling control rod drive mechanism (CRDM) system, a filter system, and a purge system. They are shown on Reference Drawing 1. A review of the effects of the power uprate to a core power of 2587 MWt was conducted and the containment air recirculation system was found to be adequate. The reactor coolant pump motors (Section 4.2.2.4) are cooled with an integral component cooling water system. The air-cooling recirculation system, air-cooling control rod drive mechanism system, and reactor pump motor coolers provide the total cooling required to limit the bulk air temperature to 125°F during normal summer operations. The minimum temperature allowed is 75°F.

5.3.1.2 Design Basis

The ventilation systems were originally designed to limit the containment bulk air temperature to below 105°F when three of the recirculating fans are running, three CRDM-cooling systems are running, and the cooling systems for the reactor coolant pump motors are functioning. Operating experience has demonstrated that the heat load in containment exceeds the original design estimates but that the ventilation systems are adequate to maintain the containment bulk air temperatures less than 125°F. The value of 125°F is the maximum containment initial temperature assumed in the design basis accident containment response evaluations.

The recirculation fan and cooling coil systems are designed to remove their portion of the heat load, under subatmospheric operating conditions, when supplied with 680 gpm of 70°F water. The relative humidity during both summer and winter operations is about 40%, with 70°F cooling water entering the recirculation coolers and 105°F bulk air temperature.

The control rod drive mechanism cooling system is designed to meet the required heat removal load when three fan cooling coil units are operating.

The two inside containment iodine filtration units are designed to remove airborne activity that may be released by nominal operational reactor coolant system leakage during subatmospheric operations.

The purge system is designed to purge the containment after the pressure has been raised to within 1-inch water gauge of atmospheric. The purging rate can be varied in steps from approximately one change per day to one change per hour. The purge exhaust is charcoal filtered for airborne radioactivity removal. If fuel is being handled within containment, the purge exhaust air flow may be directed through one or two safety related filters depending on the purge flow rate, or it may be routed through a non-safety related charcoal filter. Without fuel handling inside containment, the purge exhaust air may be routed through a nonsafety related charcoal filter. The purge system design also provides ventilation and space heating for cold weather refueling and maintenance.

Principal component data are given in Table 5.3-1.

5.3.1.3 System Descriptions

5.3.1.3.1 Air-Cooling Recirculation System

The air-cooling recirculation system consists of three 75,000-cfm (at subatmospheric conditions) fan and cooling coil banks discharging into a common ring duct from which cool supply air is ducted to the various compartments.

A vane-axial fan is installed in ductwork routed from a recirculation system discharge plenum at Elevation -27 ft. 7 in. to the containment dome area. The fan supplies approximately 10,000 cfm at subatmospheric conditions to the containment dome area to prevent warm air stratification.

Return-air transfer ducting is provided to prevent the short-circuiting of return-air flow paths, and thereby ensure cooling-air flow to the area above the operating floor. Three 36-inch-diameter ducts, each with a vane-axial fan, take suction from approximately 30 feet above the operating floor and discharge below Elevation -3 ft. Each duct has an air flow capacity of approximately 25,000 cfm. The vane-axial fans are operated with normal station power.

The recirculation system cooling coils are served primarily by the component cooling water system (Section 9.4.3.1), with backup cooling available from the chilled component cooling water system (Section 9.4.3.3).

Containment cooling design heat loads are given in Table 5.3-2.

5.3.1.3.2 Control-Rod Drive Mechanisms

The control-rod drive mechanisms are cooled by three 24,000-cfm (at subatmospheric conditions) fan and coil banks. All three units are required to provide the essential heat removal during normal operation. On Unit 1, air is drawn through the top of the shroud down over the CRDM coil stacks. On Unit 2, air is drawn through the sides of the shroud and up over the CRDM coil stacks. The air then circulates through the mechanisms, and discharges back to the containment through the cooling coils. Each fan and coil unit has two 100% flow capacity fans for redundancy.

5.3.1.3.3 Iodine Filtration Units

The inside containment iodine filtration units are self-contained packages installed on the lower level of each containment. Each consists of a 2000-cfm fan with roughing, high efficiency particulate air (HEPA), and charcoal filters installed within concrete shielding. The units are remotely operable from the control room.

5.3.1.3.4 Purge System

The containment purge supply and exhaust subsystems consist of supply and exhaust ducting arranged to ventilate either containment when the pressure has been raised to within 1-inch of water gauge of atmospheric pressure. The normal station powered supply fans are not operated to assure that the containments are negatively pressurized. The exhaust fan(s) draw outside air through low efficiency filters and a winter heating coil into containment through two isolation butterfly valves. The purge exhaust air is drawn through low-level ducts within the containment. This air flows through two isolation butterfly valves that may connect to one or both safety related filter trains or one non-safety-related filter train (Section 9.13) through two isolation dampers installed in series. The outer exhaust valve is fitted with an 8-inch bypass valve to permit reduced purge flow if required. An 18-inch pressure-equalizing valve is installed on the outside of the containment structure between the supply system penetration valves to bring the containment up to atmospheric pressure on shutdown.

The motor-operated butterfly valves are located on either side of the containment penetrations for pressure integrity. The two isolation trip dampers in series connecting the purge exhaust ducting to the safety-related filter inlet header are air operated and are designed to fail in the closed position on loss of air. The air is supplied from either the station compressed air system or through an air accumulator sized to store sufficient air to keep the dampers open for 2 hours. The butterfly valves, air-operated isolation trip dampers, and ducting leading to the safety-related filter inlet header, including the safety-related filter system, are constructed to meet seismic qualification requirements. The valves are normally kept closed except during unit shutdown when they are opened for ventilation, heating, and purging.

The purge system fans, isolation valves, and bypass and pressure equalizing valves are remote manually operated from the control room for system alignments. If a safety-injection signal is received, the purge supply fans will trip off and the isolation valves and dampers will automatically shut to isolate the containment and allow the safety-related filters to treat the air exhausted from the emergency core cooling equipment areas.

Since the Surry units have subatmospheric containments, containment purging operations are not allowed unless the unit is in cold shutdown or refueling conditions. Technical Specifications require that containment integrity be established before increasing reactor coolant temperature above 200°F, and that containment air partial pressure be within specifications before exceeding 350°F. Technical Specifications also require that the containment vacuum be maintained for all plant conditions under which the engineered safeguards systems are required to be operational. Purging is precluded under these conditions because physical limitations prohibit containment purging unless the containment vacuum is broken.

The connection to the non-safety-related charcoal filter is located between the isolation valves and isolation dampers. Although seismically supported, the connection is isolated seismically via a flexible joint from the seismic duct. When not in use, the connection is closed by installing the closed side of a spectacle flange. The maximum purge rate through this path is limited to 20,000 cfm as the filter also serves the Auxiliary Building General Exhaust.

5.3.1.4 **Design Evaluation**

Whenever the three main recirculation fan and coil units, the three CRDM fan and coil units, and the main coolant pump cooling systems are operating, the containment bulk air temperature will be maintained below 125°F. Two of the three fans in the recirculation system will continue to operate under limited main coolant leakage conditions that result in containment pressures up to but not exceeding the Consequence Limiting Safeguards (CLS) high-high containment pressure actuation setpoint (Section 7.5.1.2). The third fan will continue to operate, if normal station power is available, until stopped either manually or by actuation of an electrical fault protection device. This may provide sufficient heat removal to permit reactor shutdown under limited leakage conditions without resorting to spray injection.

The inside containment filter units will remove the airborne iodine and particulate radioactivity that could result from nominal operational leakage during subatmospheric operations.

The purge system provides the capability to change the containment air and remove radioactivity, if required, before entry for refueling and maintenance. The purge system is designed for one air change per hour and to maintain a minimum of 60°F inside the containment.

5.3.1.4.1 Incident Control

During normal operation of the plant, the containment purge system is not in use.

After unit shutdown and cooldown, purging of the containment can take place. The purge exhaust air may be directed to either the non-safety-related or safety-related ventilation filters in the auxiliary building if fuel is being handled inside containment, but no filtration is credited in the analysis. The analysis of the fuel handling accident in containment does not require that containment integrity be established prior to fuel movement. The purge design flow through the non-safety-related filter is 20,000 cfm with a limit of 30,000 cfm through the safety-related filters when containment integrity is established. If containment integrity is not established, the maximum purge exhaust rate equals the maximum safety-related fan flow limit of 39,600 cfm. The physical design and installation of the duct systems preclude exceeding these limits. The discharge of the safety-related filters and non-safety-related filter are monitored by the same system for radioactivity prior to release. Should a LOCA signal from the other unit be received, the air-operated isolation dampers will fail closed and allow the safety-related filters to treat the air exhausted from the ECCS areas. As described in Section 9.13.4.1, if a safety injection actuation occurs and auto alignment of the ventilation system is defeated, manual action is required to realign the system to the ECCS filtration mode. An alarm is received in the main control room if the purge is not realigned following a safety injection signal. This condition is not expected however, since defeating the automatic realignment is no longer credited in the fuel handling accident analysis and procedural controls have been established to eliminate operating with automatic alignment defeated.

5.3.1.4.2 Malfunction Analysis

The three air-cooling recirculating subsystems are required to maintain the containment bulk air design temperature during warm weather.

The three CRDM ventilation systems are required to provide the essential cooling.

The two inside containment self-contained particulate and iodine filter packages provide redundancy for small leakage rates.

During refueling, a high-radiation signal from the containment gas or particulate monitors or the manipulator crane area monitor will automatically trip the containment purge supply fans and close the containment isolation control valves. This automatic function is not credited in the fuel handling accident nor is it required to be operable. The operability of the containment gas and particulate monitors and the manipulator crane area monitor is relied upon in conjunction with communications to provide a timely and valid indication of a fuel handling accident in the containment.

5.3.1.5 **Tests and Inspections**

The systems are inspected, tested, and pneumatically balanced upon installation. Particulate and charcoal filters are individually tested before shipment. The filters in the purge exhaust flowpath are tested after installation and can be periodically tested for leakage and dioctylphthalate smoke test efficiency as described in Section 9.13.5.

5.3.2 Leakage-Monitoring System

The containment leakage-monitoring system was used for the preoperational integrated test of the containment and is used for the periodic measurement of leakage into the containment during normal unit operation. Section 5.3.2.2 describes two methods that can be used to monitor containment leakage: the reference volume method and the absolute method. The absolute method of leakage rate testing is the preferred method of testing due to overall test measurement accuracy. The reference volume method is not used but could be if necessary.

5.3.2.1 **Design Basis**

The leakage-monitoring system is not operational since the reference volume method is no longer used in containment leakage rate testing. The system can be made operational if necessary; however, the connections to the manometers would have to be reestablished since these are not used in the absolute system. In addition, the system would require necessary maintenance prior to use.

The absolute method applies the perfect gas law to measured changes in the containment pressure, temperature, and relative humidity, and reduces the data by means of a mathematical least-squares linear regression calculation.

Design data for the leakage-monitoring system components are given in Table 5.3-3. The system was designed in accordance with an Atomic Energy Commission Safety Guide entitled. *Reactor Containment Leakage Testing and Surveillance Requirements.*

5.3.2.2 **Description**

The absolute system consists of instruments to measure and record containment pressure, temperature, and relative humidity. These measurements are recorded at different times and the air mass in the containment is determined by the perfect gas law. Data compiled in this fashion are fitted to a linear regression equation relating time and the mass of air in the containment to leakage. Statistical methods are used to compute the variance in the results and thereby evaluate the error.

The reference volume method is based on determining the change in the pressure differential between the sealed reference system and the open-ended system of containment as caused by containment leakage. This method is limited by the difficulty in ensuring and validating the system integrity. Thus it is difficult to obtain accurate results. For this reason, the absolute method is the method of choice.

The accuracy of the test used to monitor containment leakage (ILRT) is verified by a supplemental test (superimposed method). The supplemental test is conducted for sufficient duration to accurately establish the change in leakage rates between the ILRT and the supplemental test. The results from the supplemental test are acceptable if the difference between the supplemental test data and the data obtained from either the reference volume test method or the absolute test method is within 0.25 L_a, where L_a is the maximum allowable leakage rate at the calculated peak accident pressure.

5.3.2.3 **Design Evaluation**

Periodic leakage monitoring is performed as required by Appendix J by the absolute method. This method is verified by a supplemental test (superimposed method). The absolute method is sufficiently accurate to establish that the containment leakage rate is less than the Technical Specification required leakage limit.

As part of the containment isolation system (Section 5.2), each open leakage-monitoring line penetrating the containment structure is provided with two automatic trip valves. In the event of an incident, these lines are closed and no leakage to the environment occurs. The containment leakage-monitoring system tubing, as an extension of the containment, is designed to withstand the pressure and temperature expected during an incident.

5.3.2.4 Tests and Inspections

The temporary instruments used to perform the Type A test are calibrated before each test as required by Appendix J.

5.3.3 Spray Systems

The containment-spray systems, which consist of containment-spray subsystems and recirculation-spray subsystems, are described in detail in Section 6.3.1.

The containment-spray subsystems operate during the depressurization period after a LOCA.

The containment-spray subsystems transfer chilled water from the refueling-water storage tank to the containment through the containment-spray headers. The chilled water removes sensible heat from the containment, resulting in a decrease in containment temperature and pressure. The containment-spray pumps and recirculation-spray pumps are driven by electric motors powered from either normal or emergency power sources as described in Chapter 8. The recirculation-spray subsystems recirculate water from the containment sumps through heat exchangers to the recirculation-spray headers. These subsystems provide a net heat removal from the containment. They are designed to aid in lowering the temperature and pressure within the containment and to maintain the containment subatmospheric once it is depressurized.

5.3.4 Vacuum System

The containment vacuum system is used to obtain the initial subatmospheric pressure in containment and to maintain that pressure during unit operation. It consists of a steam jet air ejector, two mechanical vacuum pumps, and the required piping, valves, and instrumentation.

Many of the containments currently in use operate at approximately atmospheric pressure. Following a LOCA, the containment pressure rises. Although the pressure can be reduced rapidly at first, the pressure-time transient curve is asymptotic to atmospheric pressure and the outleakage of fission products may continue for some time.

The subatmospheric containment concept is based on the normal operation of the containment below atmospheric pressure. Following a LOCA, the pressure will rise to above atmospheric pressure with subsequent outleakage. However, the containment temperature and pressure can be reduced rapidly, returning the containment to subatmospheric pressure and thus terminating outleakage. This is because the pressure-time curve crosses atmospheric pressure rapidly, being asymptotic to the initial subatmospheric pressure. The engineered safeguards used for pressure reduction are designed to limit the outleakage of fission products to an acceptable quantity.

Before unit operation, the containment pressure is at atmospheric pressure. During the reactor system heat-up, the pressure is reduced with a steam ejector so that containment operating pressure is reached before reactor power operation.

A subatmospheric containment pressure is maintained whenever the reactor is operating at or near design pressure and temperature. During operation, inleakage occurs and the vacuum system maintains the containment subatmospheric. The air pumped out is metered to provide a constant indication of containment system integrity. After reactor shutdown and reactor coolant system depressurization and before refueling or extended maintenance, the containment pressure is returned to atmospheric.

The initial operating temperatures for the subatmospheric and atmospheric containment are approximately equal. However, the subatmospheric containment has a lower initial air pressure.

It follows that for any containment pressure, the subatmospheric containment must have a higher steam partial pressure, which results in a higher containment temperature. The atmospheric containment would have an initial temperature of about 105°F and a temperature of approximately 273°F if allowed to rise to 50 psig following a LOCA. The subatmospheric containment starting at 10.0 psia would have an initial temperature of about 105°F and a temperature of approximately 285°F if allowed to rise to 50 psig following a LOCA.

The higher temperature for the subatmospheric containment results in the more effective operation of both static heat sinks and engineered heat removal systems. This higher temperature makes it possible to use reasonably sized water spray systems to return the containment to subatmospheric pressure and then to hold the containment subatmospheric.

The subatmospheric containment is based on known technology; 10 psia corresponds to a pressure altitude of about 10,000 feet. No difficulties have been encountered in the design and procurement of equipment for operation at this sub-atmospheric pressure. The containment is designed to resist the external pressure without new technology. The concept provides for an increase in unit safety through the reduction in possible activity release. The need for charcoal air recirculation filters and fans operating in a steam environment is eliminated and dependence is placed on a redundancy of simple spray systems.

The advantages of the subatmospheric containment are best realized if pressure is reduced rapidly to a subatmospheric level. A review of various heat removal systems indicates that the injection of cold water into the containment is the most rapid and dependable means of depressurization. This water must be borated when used in conjunction with shim-controlled reactors, since it will ultimately be recirculated to the reactor for core cooling. Depressurization is accomplished through the combined operation of the containment spray, which provides a cold-water heat sink, and the recirculation spray, which removes heat from the containment.

Transient heat transfer calculations required to size the spray systems and consider the effect of static heat sinks are well understood.

Figure 5.3-1 shows typical pressure transient curves for comparable atmospheric and subatmospheric containments following a LOCA. As shown, the pressure in the atmospheric type of containment design drops to a low value, but outleakage continues indefinitely, while outleakage is terminated in the subatmospheric containment type as soon as pressure is reduced below atmospheric.

5.3.4.1 **Design Bases**

The containment vacuum system is designed to perform the following three functions:

1. Evacuation of the containment from atmospheric pressure and maintenance of the subatmospheric pressure used for normal operation.
2. Removal of air from the containment to compensate for containment inleakage during normal operation.
3. Removal of steam and air from the containment to compensate for leakage following a design-basis accident.

The system is designed to reduce the containment pressure from atmospheric to within the Technical Specification air partial pressure limits in a time period compatible with the station start-up schedule by using the containment vacuum steam jet air ejector. To compensate for inleakage, each vacuum pump is capable of removing 5 cfm. The containment will be at a variable subatmospheric operating air partial pressure of between 10.1 and 11.3 psia whenever the reactor coolant system is at or exceeds hot standby pressure and temperature (450 psig and 350°F, minimum).

5.3.4.2 **Description**

The containment vacuum system consists of a steam jet air ejector and two mechanical vacuum pumps, with the required piping, valves, and instrumentation, as shown in Figure 5.3-2. Pump control and system instrumentation are discussed in Section 7.5. Containment vacuum system component data are given in Table 5.3-4.

The steam jet air ejector removes air from the containment to create the initial vacuum before operations, and operates on 150-psig steam provided by the auxiliary steam system, as discussed in Section 10.3.2. The air ejector is sized to draw down the containment pressure to 9.5 psia within 4 hours.

There are two five-cfm mechanical vacuum pumps, each of which can provide more than 100% of the required pumping capacity. The pumps are capable of being operated from the emergency diesel generators discussed in Section 8.5 and discharge to the process vent through the charcoal filters of the gaseous waste disposal system (Section 11.2.5).

Each containment vacuum pump is located inside a leaktight containment vacuum pump tank. A pipe running from the containment to the containment vacuum pump tank transports air from the containment to the containment vacuum pump inside the tank. The leaktight tank prevents seal leakage from the containment vacuum pump from escaping to the atmosphere.

5.3.4.3 **Evaluation**

The steam jet air ejector which is used only for initial reduction of the pressure in the containment and the vacuum pumps which are normally used during plant operations are not part of the engineered safeguards. The system is only operated when the reactor coolant system is below a temperature of 200°F. Each of the mechanical vacuum pumps is capable of removing containment inleakage and maintaining the required vacuum. The pumps are sized for intermittent and automatic operation so that, on a continual operational basis, they have the capacity for removing inleakage at a rate of about four times the design value.

The operation of the containment vacuum system is not required for several months after the design-basis accident. The containment is designed and demonstrated to have a leak rate not exceeding 0.1% per day at the design pressure. It is therefore reasonable to assume that the leakage rate, under normal plant operation and during the postaccident period, when the containment has been returned to subatmospheric pressure, will be considerably less. However, assuming the leakage rate to be independent of containment pressure, the rate of 0.1% per day would correspond to a leakage flow of 1.2 scfm and would increase containment pressure approximately 0.01 psi per day (i.e., 100 days are required to increase pressure 1 psi).

Offsetting the tendency for the containment pressure to rise as a result of the inleakage of air after the design-basis accident is the reduction in the containment pressure effected by the recirculation spray subsystem's ability to cool down the containment atmosphere further, since decay heat evolution decreases with time.

The effect of long-term leakage must be considered. Ultimately, air inleakage could result in the containment pressure increasing to atmospheric, with temperature fluctuations possibly raising the pressure to slightly above atmospheric. When the vacuum system resumes operation, it discharges through charcoal filters, which are part of the gaseous waste disposal system. Therefore, the amount of activity released to the environment is minimal.

Excess depressurization of the containment is not considered credible, since the vacuum pumps have such a small capacity when compared to the containment free volume. It requires a vacuum control system signal failure and uninterrupted operation of the vacuum pumps for approximately 17 days to result in a 1-psi decrease in containment pressure with the required capacity of 5 cfm. Alarms are provided in the control room to indicate that the containment pressure has dropped below the normal operating level. The alarm points are set at values above the design loading of the containment. This allows sufficient time for the operator to take corrective action before the pressure drops below the design loading of the containment. Administrative procedures require that the steam ejector be isolated to prevent its operation at any time other than that required during start-up of the unit. The steam ejectors are secured during normal operation by administrative control to preclude the possibility of excessive depressurization.

The minimum credible pressure expected for this containment design is caused by inadvertent operation of the containment spray system.

An evaluation of this event is performed using Charles' Law and the following initial conditions.

Minimum air partial pressure (P_1)	9.85 psia	TS limit of 10.1 psia – 0.25 psi uncertainty
Maximum bulk air temperature (T_1)	125.5°F	TS limit of 125°F + 0.5°F uncertainty
Minimum RWST temperature (T_2)	32°F	Bounding minimum value
Saturation pressure at T_2 (P_{sat})	0.09 psia	ASME Steam Tables at 32°F

Using Charles' Law for the air partial pressure (temperatures converted to Rankine), the final pressure in containment is calculated:

$$P_{total} = P_{air} + P_{vapor} = \frac{T_2}{T_1}P_1 + P_{sat}(T_2) = \frac{(460 + 32)(10.1 - 0.25)}{(460 + 125.5)} + 0.09 = 8.37 \text{ psia}$$

For an inadvertent CS actuation starting at the TS minimum air partial pressure of 10.1 psia and TS maximum air temperature of 125°F, the containment liner meets the following criteria without operator action to terminate CS.

1. Minimum containment pressure is greater than the bottom mat liner internal design pressure of 8.0 psia.
2. Minimum containment pressure is greater than the containment shell and dome internal design pressure of 3.0 psia.

5.3.4.4 Tests and Inspections

The steam jet air ejector and the mechanical vacuum pumps are not part of the engineered safeguards. Therefore, preoperational inspection of this simple mechanical device is satisfactory. The mechanical vacuum pumps were operated during the initial containment leakage rate test described in Section 5.3.2 and demonstrated adequate capacity to remove inleakage. During normal unit operation, they are alternated in service periodically, so their performance status is continually available.

5.3.5 Hydrogen Analyzer System

The requirements of TMI-2 Short Term Lessons Learned, NUREG 0578 and subsequent clarifications contained in the NRC letter dated October 30, 1979, required that there be a continuous indication of hydrogen concentration in the containment atmosphere provided in the control room. As a result, redundant hydrogen analyzers qualified to IEEE 323-1974 and IEEE 344-1975 were added with the capability of measuring over the range of 0 to 10% hydrogen concentration with containment conditions of 9 psia to 60 psia and 100% humidity. The redundant qualified hydrogen analyzers are shared by Units 1 and 2—a transfer switch with control circuitry provides for the capability of Unit 1 to utilize both analyzers or for Unit 2 to utilize both analyzers. This same circuitry allows for the operation of the direct operating electric solenoid containment isolation valves to the hydrogen analyzers.

Hydrogen analyzer H_2A-GW-104-1 has the capability of being powered from the Orange Train of Unit 1 or Unit 2 vital power and hydrogen analyzer H_2A-GW-204-1 has the capability of being powered from the Purple Train of the Unit 1 or Unit 2 vital power via switchable power sources.

Each analyzer has the capability to obtain an accurate sample within 90 minutes of the initiation of safety injection. Hydrogen concentration measurements will be indicated and recorded in the control room. The 90-minute timeframe is based upon the functional requirements provided in RG 1.7, Revision 3. Compliance with RG 1.7 ensures that indication of hydrogen concentration in the containment atmosphere is available in a timely manner to support the Emergency Plan (and related procedures) and related activities such as guidance for the severe accident management plan (References 1 & 2).

A qualified heat tracing system was added to the sample lines to each hydrogen analyzer in order to maintain a truly representative sample of containment atmosphere. The heat tracing system will be initiated on a safety injection signal.

A supply of oxygen gas is available to the hydrogen analyzer for use as the reagent gas for hydrogen recombining and a supply of hydrogen gas is available as the calibration gas.

5.3 REFERENCES

1. Letter from L.N. Hartz to USNRC, *Virginia Electric and Power Company, Dominion Nuclear Connecticut, Inc., Surry Power Station Units 1 and 2, North Anna Power Station Units 1 and 2, Millstone Power Station Units 2 and 3, Application for Technical Specification Improvement to Eliminate Requirements for Hydrogen Recombiners and Hydrogen Monitors Using the Consolidated Line Item Improvement Process,* Serial No. 04-386, dated September 8, 2004.
2. Letter from USNRC to D.A. Christian, *Surry Power Station, Units 1 and 2 - Issuance of Amendments on Elimination of Requirements for Hydrogen Monitors Using the Consolidated Line Item Improvement Process (TAC Nos. MC4393 and MC4394),* dated March 22, 2005.

5.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FB-006A	Flow/Valve Operating Numbers Diagram: Air Cooling and Purging System, Unit 1
	11548-FB-006A	Flow/Valve Operating Numbers Diagram: Air Cooling and Purging System, Unit 2

Table 5.3-1
PRINCIPAL COMPONENT DATA - CONTAINMENT SYSTEMS

System	Units Installed	Unit Capacity	Units for Normal Operation
Containment Recirculating [a]			
Cooling coil banks	3	1200 MBh	3
Fans	3	75,000 cfm	3
Fan pressure		5 in. W.G.	
Fan motors	3	125 hp	3
Control-Rod Drive Cooling [a]			
Cooling coil banks	3	726 MBh	3
Fans	6	24,000 cfm	3
Fan pressure (two-stage fans)		14.0 in. W.G.	
Fan motors	6	40 hp	3
Purge Supply			
Plenum	1	30,000 cfm	1
Fans	2	15,000 cfm	0
Fan pressure		5 in. W.G.	
Fan motors	2	15 hp	0
Heating coil		1800 MBh	
Roughing-filter bank	1	30,000 cfm	1
Carbon Filter Banks			
Safety related number	2	36,000 cfm	1
Roughing cells, per unit	30	1200 cfm	30
HEPA cells, per unit	30	1200 cfm	30
Charcoal cells, per unit	60	600 cfm	60
Inside containment number	2	2000 cfm	0

a. Fan data is at atmospheric conditions.

Table 5.3-2
CONTAINMENT COOLING DESIGN HEAT LOADS

Heat Source	Heat Load (1000 Btu/hr)	Air Flow (1000 cfm)
Steam generator cubicle “A” (Elevation 3 ft. 6 in. to 47 ft. 4 in.)	1027.0	58
Steam generator cubicle “B” (Elevation 3 ft. 6 in. to 47 ft. 4 in.)	1027.0	58
Steam generator cubicle “C” (Elevation 3 ft. 6 in. to 47 ft. 4 in.)	1040.1	59
Pressurizer cubicle (Elevation 3 ft. 6 in. to 47 ft. 4 in.)	172.7	10.5
Operating floor (Elevation 47 ft. 4 in.)	145.1	8
Annulus area	416.0	0[a]
Reactor cavity (Elevation 27 ft. 7 in.)	375.7	22.5
Incore instrument drive (Elevation 17 ft. 4 in.)	190	9
Elevation 27 ft. 7 in. (general)	100.9	0[a]
Recirculation fans	462.0	0[a]
Leakage		
Primary water, sensible heat	68.7	0[a]
Primary water, latent heat	474.7	0[a]
Main stream, sensible heat	178.0	0[a]
Main stream, latent heat	1057.0	0[a]
Total	6733.6	225
Recirculation Cooling Coil Conditions		
Air entering condition	105°F	
Air leaving condition	75°F dry bulb	
Cooling water entering condition, per coil	680 gpm	
Temperature entering	70°F	
Temperature leaving	74.5°F	
Chiller Capacity (Units 1 & 2)		
For 95°F entering bearing cooling-water temperature	400 tons; 4,800,000 Btu/hr	
Sensible Heat Loads		
Calculated equipment loads plus 15% lighting	4 W/ft^2	

a. Air circulation path

Table 5.3-3
LEAKAGE-MONITORING SYSTEM COMPONENT DESIGN DATA

Reference Volume System (Installed But Not Used)

Sealed-System Bulb Number	Open Tap Number	Bulb Location in Containment
1	1	Steam generator cubicle 1A
2	2	Steam generator cubicle 1B
3	3	Steam generator cubicle 1C
4	4	Pressurizer cubicle
5	-	Area above 47 ft. 4 in.
6	5	Area above 47 ft. 4 in.
7	-	Area above 47 ft. 4 in.
8	6	Area above 47 ft. 4 in.
9	7	Dome
10	-	Dome
11	-	Dome
12	8	Annulus
13	-	Annulus
14	-	Annulus
15	9	Annulus
16	-	Lower volume
17	-	Lower volume
18	10	Lower volume

Atmospheric Manometer (Installed But Not Used)

Type	Dual Tube, well type
Range	0-120 in. Hg
Number of scales	2, one vernier for each scale
Fill liquid	Mercury

Table 5.3-3 (CONTINUED)
LEAKAGE-MONITORING SYSTEM COMPONENT DESIGN DATA

Differential Manometer (Installed But Not Used)

Type	U-tube type, wall mounting
Range	0-60 in.
Reading accuracy	To 0.01 in. fluid with vernier
Fill liquid	D-3166 red fluid

Absolute Method System (Servomanometer) (Installed But Not Used)

Type	Precision cistern
Absolute pressure range	0-120 in. Hg
Reading accuracy to	0.001 in.
Electrical output	0-5V dc
Compensation	Temperature

Table 5.3-4
CONTAINMENT VACUUM SYSTEM COMPONENT DESIGN DATA

Containment Vacuum Pumps	
Number	4 (2 per unit, 1 required)
Type	Rotary vane, oil free
Power source	Station electric or standby generators
Capacity	5 cfm
Steam Jet Ejector	
Number	2 (1 per unit)
Power source	150 psig steam
Capacity	52,000 lb of air in 4 hours
Containment Vacuum Pump Tank	
Number	4 (2 per unit)
Volume	10 ft^3
Design pressure	Full vacuum
Design temperature	300°F
Operating pressure	9.5 psia
Operating temperature	105°F
Material	A285 GR C

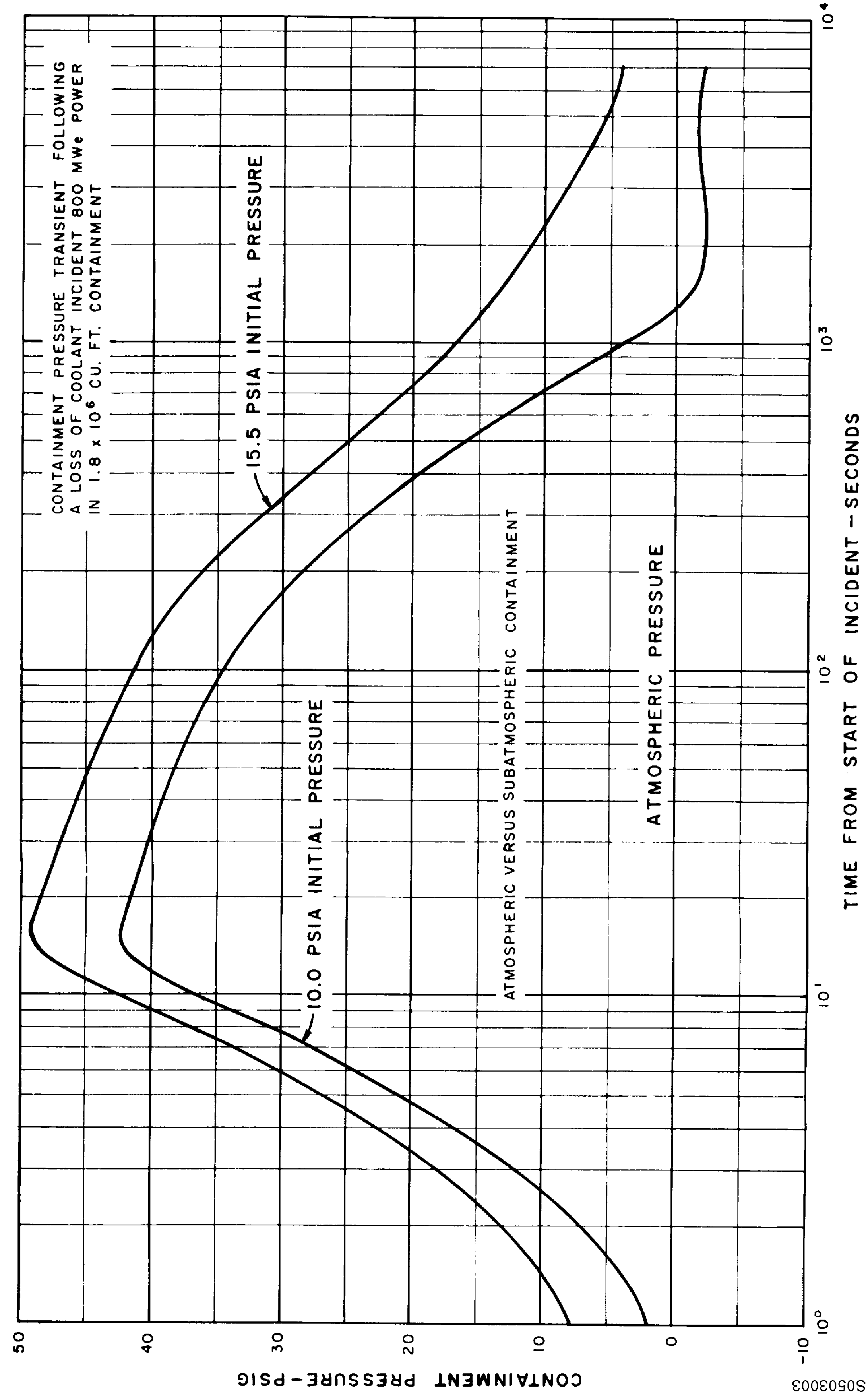
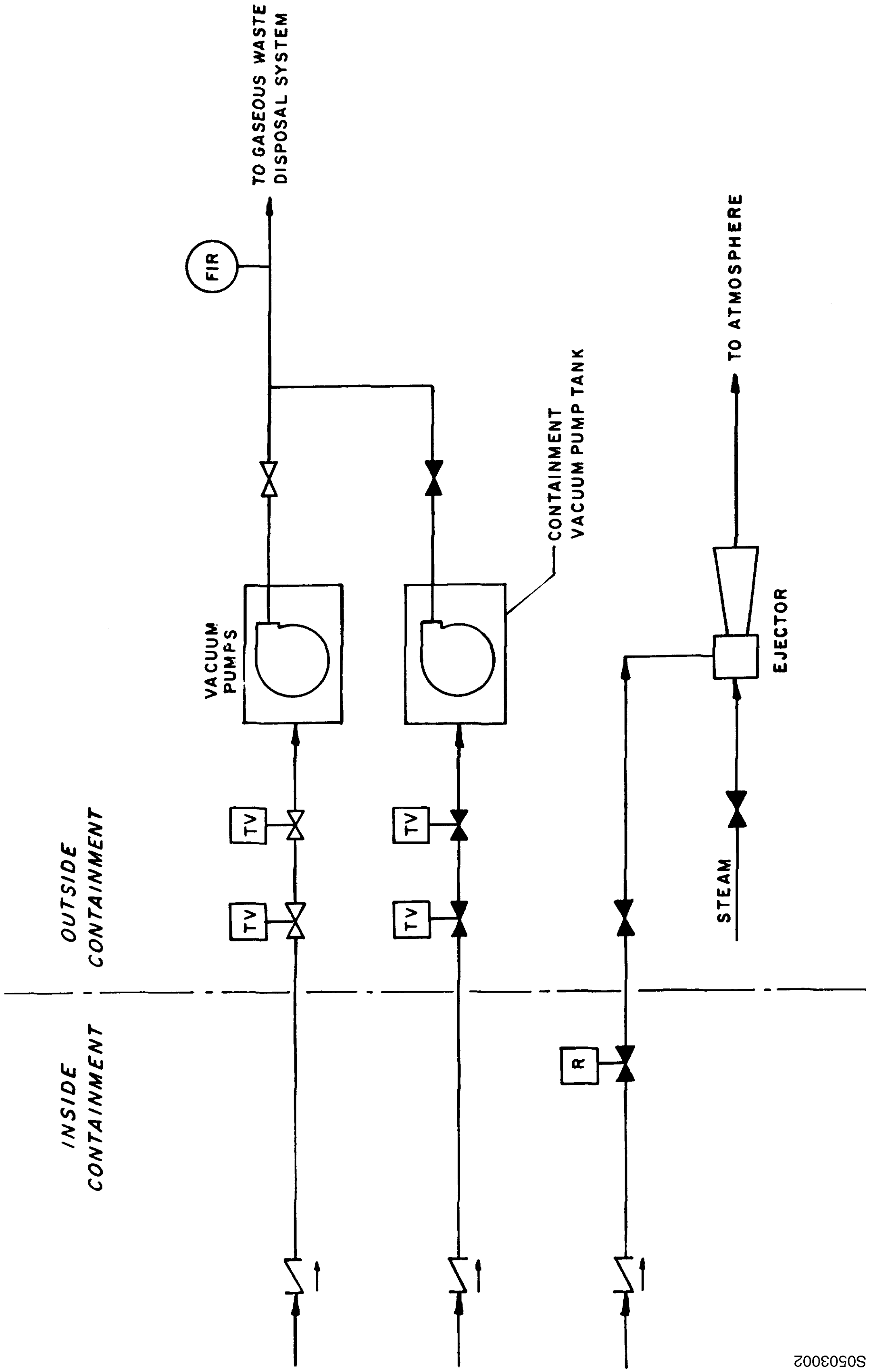


Figure 5.3-1
TYPICAL CONTAINMENT PRESSURE TRANSIENT CURVES; SURRY POWER STATION

Figure 5.3-2
CONTAINMENT VACUUM SYSTEM



5.4 CONTAINMENT DESIGN EVALUATION

The reactor containment is maintained at a subatmospheric pressure in which the air partial pressure varies between approximately 10.1 and 11.3 psia. The containment shell and dome are designed to withstand an internal pressure as low as 3 psia, and the containment bottom mat liner is designed to withstand an internal pressure as low as 8 psia. The Technical Specifications specify the partial pressure limitations as a function of service-water temperature. The allowable variation is based on the ability of the containment heat removal systems to depressurize the containment and depends on seasonal temperature changes in the service water and thermal recirculation effects. The containment design pressure is 45 psig, which is greater than the peak post-LOCA pressure, based on a double-ended hot-leg rupture. The containment returns to subatmospheric pressure within 60 minutes of the occurrence of the accident, thus terminating outleakage from the containment (Section 14.5.5). This original design criterion was modified in conjunction with the analyses for implementation of the alternative source term. The criteria were subsequently updated to support an increase in the containment depressurization profile for the alternative source term analyses. The updated criteria require that, following the LOCA, the containment pressure be less than 2.0 psig within 1 hour and less than 0.0 psig within 6 hours. The radiological consequences analysis demonstrates acceptable results provided the containment pressure does not exceed 2.0 psig for the interval from 1 to 6 hours following the Design Basis Accident. Beyond 6 hours, containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

A subatmospheric containment limits the outleakage of fission products to meet 10 CFR 50.67 criteria for the design-basis accident as discussed in Section 14.5.6, using conventional spray cooling as described in Section 6.3.1.

At the design containment leak rate of 0.1% of contained volume per day, air inleakage is not significant for a considerable length of time after a LOCA. Ultimately, air inleakage, combined with ambient barometric pressure fluctuations, could result in a containment pressure slightly above atmospheric. To prevent this, the vacuum system maintains the containment pressure at several inches of mercury below the lowest expected atmospheric pressure during normal operation. The vacuum cannot be lost rapidly because of the inherent low-leakage design features of the containment.

The containment isolation features, such as penetrations, access hatches, and isolation valves, have been designed so that double barriers or seals exist between the interior of the containment and the environment. Hence, there are no direct leakage paths between the containment and the environment.

The seismological design bases for the reactor containment are described in Sections 2.5 and 15.2.4.

The containment structural design was in accordance with then current design practices for steel-lined, reinforced-concrete reactor containment structures. The design was based on accepted analytical methods and does not vary in any significant feature from structures then being licensed or approved for construction. Rigid controls were maintained for all the materials, and the construction practices were as indicated in Chapter 15. Subatmospheric pressure operation results in no significant effect on the structural design.

The subatmospheric containment system does not depart in any significant way from good engineering design practices as used for atmospheric containments, yet it provides a substantial increase in public safety.

The following sections provide descriptions of the analytical models used to calculate the containment pressure and temperature responses to the design basis loss of coolant accident.

5.4.1 LOCA Mass and Energy Release Analysis

5.4.1.1 **Purpose of Analysis**

The analysis documented in this section involves calculations of the long term Loss of Coolant Accident (LOCA) mass and energy releases for the double-ended pump suction guillotine (DEPSG) and double-ended hot leg guillotine (DEHLG) break cases with the proposed uprated conditions. This documentation provides the analytical basis with respect to the LOCA containment mass and energy release for the operation of the Surry Power Station Unit 1 and 2 at the described conditions.

Rupture of any of the piping carrying pressurized high temperature reactor coolant, termed a LOCA, will result in release of steam and water into the containment. This, in turn, will result in an increase in the containment pressure and temperature. The mass and energy release rates described in this section are used in further computations to evaluate the containment heat removal systems capability and containment structural integrity following a postulated loss of coolant accident. These analyses are performed to demonstrate compliance with General Design Criteria 38 and 50 of 10 CFR 50, Appendix A. Section 5.4.1.2 presents the long term mass and energy release analysis for containment pressurization evaluations. Section 5.4.1.3 presents the post-blowdown mass and energy releases for use in evaluation of recirculation spray pump available NPSH.

5.4.1.2 **System Characteristics and Modeling Assumptions**

The mass and energy release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Some of the most critical items are: RCS initial conditions, core decay heat, safety injection flow, and metal and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed below. Tables 5.4-1 through 5.4-5 present key data assumed in the analysis.

For the long term mass and energy release calculations, operating temperatures which bound the highest full power average coolant temperature were used as initial conditions. A core rated power of 2587 MWt (adjusted for calorimetric error of +0.38% of power) was assumed. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures which are at the maximum levels attained in steady state operation. Additionally, an allowance of +4.0°F is reflected in the temperatures in order to account for instrument error and deadband. The initial Reactor Coolant System (RCS) pressure in this analysis is based on a nominal value of 2250 psia. Also included is an allowance of +30 psi, which accounts for the measurement uncertainty on pressurizer pressure. The selection of 2250 psia as the limiting pressure is considered to affect the blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature) and subsequently has a higher RC mass available for releases. Thus, 2280 psia initial pressure was selected as the limiting case for the long term mass and energy release calculations. A 3% increase in the nominal RCS volume (which is composed of 1.6% allowance for thermal expansion and 1.4% for uncertainty) is also modeled. These assumptions conservatively maximize the mass and energy contained in the RCS.

The selection of the core model for the long term mass and energy calculation is based on the need to conservatively maximize the core stored energy. To maximize the core stored energy used in the analysis, an upper bound value is used which addresses the effect of uncertainties in the fuel temperature models and the material properties. The fuel design features and conditions used in the calculation of fuel temperatures for the core stored energy are selected to be bounding for the Surry reload cores. The core stored energy is calculated following the methodology of WCAP-17642-P-A.

Regarding safety injection flow, the mass and energy calculation considered configurations to conservatively bound potential alignments. The spectrum of cases included: Minimum SI - Single Train (conservatively low ECCS flowrates); Maximum SI - Single Train (conservative early depletion of refueling water storage tank); and Maximum SI - Two Train (nominal configuration).

The following assumptions were employed to ensure that the mass and energy releases are conservatively calculated, thereby maximizing energy release to containment:

1. Maximum expected operating temperature of the Reactor Coolant System (100% power conditions).
2. An allowance in temperature for instrument error and dead band (+4.0°F).
3. Margin in RCS volume of 3% (which is composed of 1.6% allowance for thermal expansion and 1.4% for uncertainty).
4. Core rated power of 2587 MWt.

5. Allowance for calorimetric error (+0.38% power).
6. Conservative coefficient of heat transfer (i.e., steam generator primary/secondary heat transfer and Reactor Coolant System metal heat transfer).
7. Allowance in core stored energy for effect of fuel densification.
8. An upper bound calculation of core stored energy which addresses the effect of uncertainties in the fuel temperature models and the material properties.
9. An allowance for RCS initial pressure uncertainty (+30 psi).
10. A maximum containment backpressure equal to design pressure.
11. The steam generator (SG) metal mass was modeled to include only the portion of the SG which is in contact with the fluid on the secondary side (i.e., 474,000 lbm/SG out of a possible 691,000 lbm). Portions of the SGs such as the elliptical head, upper shell, and miscellaneous internals have poor heat transfer due to their location with respect to the secondary side water level. The energy stored in these areas available for release to the primary side break flow will not be able to effectively transfer energy to the RCS, thus the energy will be removed at a much slower rate and time period (i.e., >10,000 seconds).
12. A provision for modeling steam flow from the secondary side to the turbine through the turbine isolation valve was conservatively addressed with the control systems and setpoints in the modeling code. The valve isolation time was modeled as occurring at 1.5 seconds after the low pressurizer pressure reactor trip setpoint was reached.
13. As noted in Section 2.4 of Reference 2, the option to provide more specific modeling pertaining to decay heat has been exercised to specifically reflect the Surry Unit 1 and 2 core heat generation, while retaining the two sigma uncertainty to assure conservatism.
14. Steam generator tube plugging level (0% uniform).
    - Maximizes reactor coolant volume and fluid release.
    - Maximizes heat transfer area across the SG tubes.
    - Reduces coolant loop resistance, which reduces Δp upstream of break and increases break flow.
15. The main feedwater flow was modeled as a linear coastdown over a duration of ten seconds. The coastdown was modeled as occurring after the low pressurizer pressure-SI trip setpoint was reached plus a signal processing time.

Use of the above conditions and assumptions result in a bounding analysis of the release of mass and energy from the RCS in the event of a LOCA. This analysis is applicable for operation of Surry Unit 1 and 2 at a core rated power of 2587 MWt.

5.4.1.3 **Long Term LOCA Mass and Energy Release Analysis**

5.4.1.3.1 Introduction

The evaluation model used to the long term LOCA mass and energy release calculations was the March 1979 model described in Reference 2. This evaluation model has been reviewed and approved by the NRC, and has been used in the analysis of other dry containment plants. These mass and energy releases are used in the containment response analysis described in Section 5.4.2. A discrepancy between volumetric heat capacities used in WCAP-10325-P-A (Reference 2) and those documented in more recent ASME Code documents was identified. This condition was addressed in PWROG-17034-P-A (Reference 13), where the NRC determined, with various generic methodology issues addressed, the continued use of WCAP-10325-P-A is acceptable for performing LOCA mass and energy release analysis for plants with large dry and sub-atmospheric containments.

5.4.1.3.2 LOCA Mass and Energy Release Phases

The containment system receives mass and energy releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA mass and energy analysis, is typically divided into four phases:

1. Blowdown—the period of time from accident initiation (when the reactor is at steady state operation) to the time that the RCS and containment reach an equilibrium state.
2. Refill—the period of time when the lower plenum is being filled by accumulator and ECCS water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer and lower plenum. To conservatively consider the refill period for the purpose of containment mass and energy releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of mass and energy to containment. Thus, the refill period is conservatively neglected in the mass and energy release calculation.
3. Reflood—begins when the water from the lower plenum enters the core and ends when the core is completely quenched.
4. Post-reflood (GOTHIC)—describes the period following the reflood transient. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs and is superheated in the steam generators. After the broken loop steam generator cools, the break flow becomes two phase.

Computer Codes

The Reference 2 mass and energy release evaluation model is comprised of mass and energy release versions of the following codes: SATAN VI and WREFLOOD. These codes were used to calculate the long term LOCA mass and energy releases through the end of reflood for the Surry Power Station Unit 1 and 2. GOTHIC calculates the post reflood mass and energy releases in accordance with Topical Report DOM-NAF-3 (Reference 8).

SATAN calculates blowdown, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, mass and energy flowrates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the Emergency Core Cooling refills the reactor vessel and provides cooling to the core. The most important feature is the steam/water mixing model. (See Section 5.4.1.3.5.2.)

GOTHIC models the post-reflood portion of the transient. The GOTHIC code is used for the transfer of decay heat and the stored energy in the primary and secondary systems to the containment.

5.4.1.3.3 Break Size and Location

Generic studies have been performed with respect to the effect of postulated break size on the LOCA mass and energy releases. The double ended guillotine break has been found to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and froth phases, the break size has little effect on the releases.

Three distinct locations in the reactor coolant system loop can be postulated for pipe rupture:

1. Hot leg (between vessel and steam generator)
2. Cold leg (between pump and vessel)
3. Pump suction (between steam generator and pump)

The break locations analyzed for this program are the double-ended pump suction guillotine, DEPSG (10.48 ft^2) and the double-ended hot leg guillotine, DEHLG (9.18 ft^2). Break mass and energy releases have been calculated for the blowdown, reflood and post-reflood phases of the LOCA for each case analyzed. The following information provides a discussion on each break location.

The DEHLG has been shown in previous studies to result in the highest blowdown mass and energy release rates. Although the core flooding rate would be the highest for this break location, the amount of energy released from the steam generator secondary is minimal because the majority of the fluid which exits the core bypasses the steam generators venting directly to containment. As a result, the reflood mass and energy releases are reduced significantly as compared to either the pump suction or cold leg break locations where the core exit mixture must pass through the steam generators before venting through the break. For the hot leg break, generic studies have confirmed that there is not reflood peak (i.e., from the end of the blowdown period the containment pressure would continually decrease). The DEHLG reflood and post-reflood phase calculations are not required to determine peak containment pressure, but were calculated for use in the calculation for the recirculation spray pump available NPSH. Further details about the hot leg mass and energy analysis are contained in Section 5.4.1.4. The mass and energy releases for the hot leg break blowdown phase are included in the present section.

The cold leg break location has also been found in previous studies to be much less limiting in terms of the overall containment energy releases. The cold leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than for the pump suction break. During reflood, the reflooding rate is greatly reduced and the energy release rate into the containment is reduced. Since the DEPSG case provides bounding results, the cold leg break location is not explicitly analyzed.

The pump suction break combines the effects of the relatively high core flooding rate, as in the hot leg break, and a break flow path through which the stored energy in the steam generators can be transferred to the containment. As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period since all of the Reactor Coolant System available energy contributes to the calculated mass and energy releases.

5.4.1.3.4 Assessment of Single Failure Effects

An analysis of the effects from various single failures has been performed on the mass and energy release rates for each break analyzed. An inherent assumption in the generation of the mass and energy release is that offsite power is lost. This results in the actuation of the emergency diesel generators, required to power the safety injection system. This is not an issue for the blowdown period which is limited by the DEHLG break.

Three cases have been analyzed for the effects of a single failure. In the case of minimum safeguards, the single failure postulated to occur is the loss of an emergency diesel generator. This results in the loss of one pumped safety injection train. Two variations on the minimum safeguards scenario were addressed. The first case was a maximum safety injection (SI) flow, single train case. This case will result in low flow rates, but an early refueling water storage tank depletion. The second configuration is the minimum SI flow, single train case. As compared to the first case the SI flow would be minimized, although the time of RWST depletion would be later. Sensitivities indicate that containment depressurization time is more limiting for the minimum SI-single train case. Containment depressurization peak pressure and LHSI pump NPSH are more limiting for the maximum SI-single train scenario. For the case of maximum safeguards, no failure is postulated to occur. Sensitivity cases using mass and energy data for the pump suction, maximum safeguards case indicated that this configuration is not limiting for any analysis acceptance criteria. Therefore, no detailed data or containment analysis results are presented for this case. The analysis of the cases described ensures that the effect of all credible single failures is bounded.

5.4.1.3.5 Mass and Energy Release Data

5.4.1.3.5.1 *Blowdown Mass and Energy Release Data*

A version of the SATAN-VI code, which is the code used for the Emergency Core Cooling System (ECCS) calculation in Reference 3 is used for computing the blowdown transient. The code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermodynamic equilibrium is assumed in each element. A point kinetic model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody) or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in Reference 2.

5.4.1.3.5.2 *Reflood Mass and Energy Release Data*

The WREFLOOD code used for computing the reflood transient is a modified version of that used in the 1981 ECCS evaluation model (Reference 3).

The WREFLOOD code consists of two basic hydraulic models—one for the contents of the reactor vessel, and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena, such as pumped safety injection and accumulators, reactor coolant pump performance and steam generator release, are included as auxiliary equations which interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters, such as core flooding rate, core and downcomer water levels, fluid thermodynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break, i.e., the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and emergency core cooling injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the usage and application of the Reference 2 mass and energy release evaluation model in recent analyses, e.g., D. C. Cook Docket (Reference 4). Even though the Reference 2 model credits steam/mixing only in the intact loop and not in the broken loop, justification, applicability and NRC approval for using the mixing model in the broken loop has been documented (Reference 4). This assumption is justified and supported by test data, and is summarized as follows:

The model assumed a complete mixing condition (i.e., thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two phase interaction with condensation of steam by cold ECCS water. The second is a single phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that need be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data has been reviewed for validation of the containment integrity reflood steam/water mixing model. This data is that generated in 1/3 scale tests (Reference 5), which are the largest scale data available and thus most clearly simulates the flow regimes and gravitational effects that would occur in a PWR. These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

From the entire series of 1/3 scale tests, a group corresponds almost directly to containment integrity reflood conditions. The injection flowrates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in Reference 2. For all of these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is therefore wholly supported by the 1/3 scale steam/water mixing data.

Additionally, the following justification is noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the double-ended pump suction guillotine. For this break, there are two flowpaths available in the RCS by which mass and energy may be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the reactor coolant pump. Steam which is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken loop cold leg and pump in venting to containment. This steam also encounters ECCS injection water as it passes through the broken loop cold leg, complete mixing occurs and a portion of it is condensed. It is this portion of steam which is condensed that is taken credit for in this analysis. This assumption is justified based upon the postulated break location, and the actual physical presence of the ECCS injection nozzle. A description of the test and test results is contained in References 2 and 5.

The methodology previously discussed in Reference 2 has been utilized and approved on the Dockets for numerous dry containment plants such as Beaver Valley Unit 2, Millstone Unit 3 and Indian Point Unit 2.

The blowdown and reflood mass and energy release data (including the transients of principal parameters during reflood) are provided in Section 5.4.2 as composite tables of data used in the containment response analysis. Section 5.4.2 describes the usage of these data in the GOTHIC code.

5.4.1.3.5.3 *Post-Reflood Mass and Energy Release Data*

The GOTHIC code (Reference 8) is used for computing the post-reflood transient. GOTHIC calculates the transfer of decay heat and the stored energy in the primary and secondary systems to the containment. The mass and energy releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken loop and intact loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure, but the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two phase fluid exits the core, flows through the hot legs and becomes superheated as it passes through the steam generator. Once the broken loop cools, the break flow becomes two phase.

The mass and energy release rates calculated by GOTHIC are processed as described in Section 5.4.2.1 for use in the containment response analysis.

5.4.1.3.5.4 *Decay Heat Model*

As part of the Surry Core Uprating effort a detailed DEHLG mass and energy release analysis (Section 5.4.1.4) was completed for use in the evaluation of recirculation spray pump available NPSH. The 1975 mass and energy release evaluation model (Reference 6) was used for this calculation. The decay heat standard available and incorporated into the Reference 6 evaluation model was adopted by the ANS Standards Subcommittee in October 1971.

The NRC staff Safety Evaluation Report (SER) for the March 1979 evaluation model approved use of the November 1979 ANS Standard-5.1 decay heat model for the calculation of mass and energy releases to the containment following a loss-of-coolant accident. Therefore, to more realistically model the RCS, the Reference 7 decay heat model was utilized for this core uprating effort in conjunction with the 1975 evaluation model. The Reference 7 decay heat model is utilized in the GOTHIC containment analysis. This standard was used in the mass and energy release model with the following input specific for the Surry Power Station Unit 1 and 2. The primary assumptions which make this calculation specific for the Surry Power Station are the enrichment factor, minimum/maximum number of the new fuel assemblies per cycle and fuel cycle length. A conservative lower bound for enrichment of 3% was used. Table 5.4-2 lists the decay heat values used in this analysis.

Significant assumptions in the generation of the decay heat values:

1. Decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.

2. Decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.

3. Fission rate is constant over the operating history of maximum power level.

4. The factor accounting for neutron capture in fission products has been taken from Equation 11 of Reference 7 up to 10,000 seconds, and Table 10 of Reference 7 beyond 10,000 seconds.

5. The fuel has been assumed to be at full power for 10^8 seconds.
6. The number of atoms of U-239 produced per second has been assumed to be equal to 70% of the fission rate.
7. The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.
8. Two sigma uncertainty (two times the standard deviation) has been applied to the fission product decay.
9. End of cycle core average burnup that is less than or equal to 40,000 MWD/MTU.
10. Core fresh fuel loading that is greater than or equal to 72.5 MTU.
11. Core average fuel enrichment that is greater than or equal to 3.0%.

5.4.1.3.6 Sources of Mass and Energy

The sources of mass considered in the LOCA mass and energy release analysis are the reactor coolant system, accumulators and pumped safety injection.

The energy inventories considered in the LOCA mass and energy release analysis include:

1. Reactor Coolant System Water
2. Accumulator Water
3. Pumped Injection Water
4. Decay Heat
5. Core Stored Energy
6. Primary Metal
7. Steam Generator Metal (includes transition cone, shell, wrapper, and other internals)
8. Steam Generator Secondary Energy (includes fluid mass and steam mass)
9. Secondary Transfer of Energy (feedwater into and steam out of the steam generator secondary)
10. SG tubes

In the mass and energy release data presented, no Zirc-water reaction heat was considered because the clad temperature did not rise high enough for the rate of the Zirc-water reaction heat to be of any significance.

The consideration of the various energy sources in the mass and energy release analysis provides assurance that all available sources of energy have been included in this analysis. Thus the review guidelines presented in Standard Review Plan Section 6.2.1.3 have been satisfied.

5.4.1.4 Mass and Energy Releases for Available NPSH Analysis (Hot Leg Double Ended Rupture, Post-Blowdown)

In support of the evaluation of recirculation spray pump and low head safety injection pump available NPSH, a LOCA long term mass and energy release analysis was completed. Mass and energy releases for use in the DEHLG evaluation, Maximum Safety injection - two train case are provided in Table 5.4-6. The DEHLG data is presented for two break paths. Break path 1 represents the mass and energy exiting from the reactor vessel side of the break. Break path 2 is the mass and energy exiting from the SG side of the break.

The large break LOCA mass and energy releases were generated using the evaluation models described in References 2 and 6. The blowdown phase mass and energy releases were calculated using the Reference 2 evaluation model, as described in Section 5.4.1.3.5.1 and provided in Table 5.4-6. The large break LOCA mass and energy releases for the reflood phase was generated using the 1975 mass and energy release evaluation model (Reference 6). Table 5.4-6 provides the hot leg mass and energy instantaneous releases, plus reflood mass and energy data for the reflood phase. The Reference 6 mass and energy release evaluation model was utilized because of its capability to calculate reflood phase transient mass and energy release data. The focus of the Reference 2 evaluation model is for the pressure and temperature response of containment. As noted in Section 5.4.1.3.3, generic studies confirm that for the hot leg break, there is no reflood peak, therefore the reflood code applicability of the Reference 2 model was not pursued. The Reference 6 evaluation model still remains a valid analytical tool that has been reviewed and approved by the NRC, although it does not exhibit the benefits of the improved model, i.e., steam water mixing model during reflood. Please note the reflood phase modeling of the Reference 6 evaluation model has been enhanced to incorporate the 1979 decay model as described in Section 5.4.1.3.5.4 for this Surry core uprating program. The DEHLG mass and energy releases in Table 5.4-6 are based on the initial conditions consistent with the design basis analysis of Section 5.4.1.3.

The analysis performed to calculate long term mass and energy releases following a postulated DEHLG is similar to the analysis described in Section 5.4.1.3. The transient is divided into four phases: blowdown, refill, reflood and post-reflood. The characteristics of the phases are also similar except for the hot leg break, where the amount of energy released from the SG is minimal because the majority of the fluid which exits the core bypasses the SG venting directly to containment.

The analysis as noted above utilized both the Reference 2 and 6 mass and energy release evaluation models. The computer models used were comprised of mass and energy release versions of the following codes: SATAN VI model (Reference 2) for blowdown, WREFLOOD model (Reference 6) for reflood phase, and GOTHIC (Reference 8) for the post-reflood phase. These codes were used to calculate the long term LOCA mass and energy releases for the hot leg break. The blowdown releases are calculated with the same version of the SATAN code described in Section 5.4.1.3.2.

The WREFLOOD code addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the Emergency Core Cooling System refills the reactor vessel and provides cooling to the core. The WREFLOOD version of the Reference 6 model does not include the enhanced steam/water mixing model of Reference 2.

5.4.2 LOCA Containment Pressure and Temperature Response

The containment pressure and temperature response is analyzed for the primary system breaks which are discussed in Section 5.4.1. Various single failures of the engineered safety features are analyzed to identify the limiting single failures.

There is one pressure peak following a Reactor Coolant System (RCS) hot leg or cold leg rupture. This pressure peak occurs near the end of the initial blowdown of the RCS after a double ended guillotine (DEG) of either a hot or cold leg. This will be referred to as the blowdown peak pressure. Its magnitude is a function of the following parameters:

1. The containment free volume.
2. The mass of air inside the containment structure (a function of initial pressure and temperature).
3. The amount of energy flow out of the break during the initial blowdown of the RCS.
4. The rate of heat removal from the containment atmosphere by the passive heat sinks within the containment structure.

A DEHLG produces the largest blowdown peak pressure. This event releases the most energy to the containment atmosphere during the initial blowdown since the hot leg pipe size is larger than that of a RCS pump discharge and there is no resistance to flow due to a RCS pump as is the case with a DEPSG. The magnitude of the blowdown peak pressure is independent of the active engineered safety feature (ESF) because ESF does not become effective until after the peak pressure occurs. However, the accumulators do have a small effect on the blowdown peak pressure.

Following the core reflooding period, the containment depressurization systems and containment passive heat sinks remove energy from the containment atmosphere at a rate sufficient to reduce the pressure to below atmospheric pressure in less than 60 minutes. The depressurization time is a function of the following parameters:

1. The containment free volume.
2. The mass of air inside the containment structure.
3. The rate of heat transfer between the containment atmosphere and the passive heat sinks within the containment structure.

4. The rate of heat removal from the containment atmosphere by the containment heat removal systems (this is significantly dependent on the ultimate heat sink temperature).
5. The rate of mass and energy release to the containment from the break following the end of core reflooding.
6. The mass of nitrogen added to the containment from the SI accumulators.

After the containment is depressurized, the depressurization systems continue to remove energy from the containment at a rate sufficient to maintain the containment at subatmospheric pressure. The heated passive heat sinks add energy back to the containment atmosphere following depressurization. The containment experiences a pressure peak less than 1.0 psig after the termination of containment spray associated with emptying the RWST.

5.4.2.1 **Containment Response Analytical Model**

The GOTHIC computer program which is used to model the containment system, the passive heat sinks, and the containment heat removal systems, was developed for the Electric Power Research Institute (EPRI) by Numerical Applications, Inc. A topical report (DOM-NAF-3) described in detail the assumptions used and the mathematical formulations employed. The use of GOTHIC for containment analysis has been approved by the NRC as documented in DOM-NAF-3-0.0-P-A (Reference 8).

GOTHIC solves the conservation equations for mass, momentum, and energy for multi-component, multi-phase flow in lumped parameter and/or multi-dimensional geometries. The phase balance equations are coupled by mechanistic models for interface mass, energy and momentum transfer that cover the entire flow regime from bubbly flow to film/drop flow, as well as single phase flows. The interface models allow for the possibility of thermal non-equilibrium between phases and unequal phase velocities, including countercurrent flow. GOTHIC includes full treatment of the momentum transport terms in multidimensional models, with optional models for turbulent shear and turbulent mass and energy diffusion. Other phenomena include models for commonly available safety equipment, heat transfer to structures, hydrogen burn and isotope transport.

5.4.2.1.1 Passive Heat Sinks

Thermal conductors are the primary heat sink for the blowdown energy. The conductors can be made up of any number of layers of different materials. One-dimensional conduction solutions are used to be consistent with the lumped modeling approach.

The thermal conductor is divided into regions, one for each material layer, with an appropriate thickness and material property for each region. GOTHIC accepts inputs for material density, thermal conductivity and specific heat. These values are obtained from published literature for the materials present in each conductor. Conductors with high heat flux at the surface and low thermal conductivity must have closely spaced nodes near the surface to adequately track the steep temperature profile. The node spacing is set so the node Biot number for each node is less than 0.1. The Biot number is the ratio of external to internal conductance.

It is not practical or necessary to model each individual piece of equipment or structure in the containment with a separate conductor. Smaller conductors of similar material composition can be combined into a single effective conductor. In this combination, the total mass and the total exposed surface area of the conductors is preserved. The thickness controls the response time for the conductors and is of secondary importance. The conductors are grouped by thickness and material type. The effective thickness for a group of wall conductors is calculated by the equation below. The heat sink material types, surface areas, and thickness are derived based on plant-specific inventories. Concrete, carbon steel, and stainless steel are the most common materials.

$$t_{eff} = \frac{\sum_{i \in group} t_i A_i}{\sum_{i \in group} A_i}$$

If there is a small air gap or a contact resistance between the containment liner and the concrete, it is modeled as a separate material layer at the nominal gap thickness with applicable material properties. This overestimates the contact resistance because convection and radiation effects will be ignored. A maximum gap conductance of 40 Btu/hr-ft^2-F is used. The gap width is determined by dividing the gap thermal conductivity by the gap conductance.

All containment passive heat sinks are included in the lumped containment volume. The primary system metal and SG secondary shells are included in the simplified RCS model that is used for the calculation of long-term mass and energy release; however, these conductors are not used for condensation or convection heat transfer with the containment atmosphere.

5.4.2.1.2 Conductor Surface Heat Transfer

The Direct heat transfer option with the DLM (Diffusion Layer Model) condensation option is used for all containment passive heat sinks except the sump floor. With the Direct option, all condensate goes directly to the liquid pool at the bottom of the volume. The effects of the condensate film on the heat and mass transfer are incorporated in the formulation of the DLM option. Under the DLM option, the condensation rate is calculated using a heat and mass transfer analogy to account for the presence of non-condensing gases.

For a conductor representing the containment floor or sump walls that will eventually be covered with water from the break and condensate, the Split heat transfer option is used to switch the heat transfer from the vapor phase to the liquid phase as the liquid level in the containment builds. A quicker transition to liquid heat transfer is more conservative for containment analysis. The Split option is used with $\alpha_{1_{max}}$, the maximum liquid fraction, set to

$$\alpha_{1_{max}} = \frac{d}{H}$$

where d is the transition water depth and H is the volume height. A reasonable value for d of 0.1 inch switches the heat transfer from the vapor phase to the liquid phase as the liquid level in the containment reaches 0.1 inch. Other values may be appropriate depending on the geometry of the floor and sump.

For conductors with both sides exposed to the containment, the Direct option is applied to both sides. Alternatively, if the conductor is symmetric about the centerplane, a half-thickness conductor can be used with the total surface area of the two sides and an insulated back side heat transfer option. The conductor face that is not exposed to the atmosphere is assumed insulated. The Specified Heat Flux option is used with the nominal heat flux set to zero.

Containment walls above grade and the containment dome have a specified external temperature boundary condition with a heat transfer coefficient of 2.0 Btu/hr-ft^2-F to model convective heat transfer to the outside atmosphere. The GOTHIC heat transfer solution scheme allows for accurate initialization of the temperature distribution in the containment wall and dome prior to the transient initiation.

A conservative containment liner response is obtained by adding a small conductor that has the same construction and properties as the liner conductor. A conductor surface area of 1 ft^2 is used to minimize impact on the lumped containment pressure and temperature response. The inside heat transfer option is the same as used for the actual liner conductor (Direct with DLM) with a multiplier of 1.2 for conservatism.

5.4.2.1.3 Spray Modeling

GOTHIC includes models that calculate the sensible heat transfer between the drops and the vapor and the evaporation or condensation at the drop surface. The efficiency—the actual temperature rise over the difference between the vapor temperature and the drop inlet temperature—cannot be directly specified in GOTHIC. The efficiency is primarily a function of the drop diameter. The GOTHIC models account for the effect of the diameter through the Reynolds number dependent fall velocity and heat transfer coefficients. A heat and mass transfer analogy is used to calculate the effective mass transfer coefficient, which is used to calculate the evaporation or condensation. Containment spray is modeled as described in DOM-NAF-3-0.0-P-A.

5.4.2.1.4 Containment Heat Removal

Heat exchangers that remove energy from the containment sump are modeled with the available heat exchanger options in GOTHIC. Use of a GOTHIC heat exchanger option dynamically couples the heat exchanger performance to the predicted primary and secondary fluid conditions. This can provide a small benefit compared to other codes (e.g., LOCTIC) that use bounding UA values to cover the fluid conditions predicted over the entire transient.

The GOTHIC heat exchanger type that closely matches the actual heat exchanger is selected. The inside and outside heat transfer areas are calculated from the heat exchanger geometry details. For tube and shell arrangements, the shell side flow area is set to the open area across the tubes at the mid-plane of the heat exchanger and the shell side hydraulic diameter is set to the tube outer diameter. The GOTHIC option for built-in heat transfer coefficients is used to determine heat transfer coefficients that depend on the primary and secondary side Reynolds and Prandtl numbers. The heat exchanger models in GOTHIC are for basic heat exchanger designs and may not account for the details of a particular heat exchanger (e.g., baffling in a tube-and-shell heat exchanger). A forcing function can be used on the primary and secondary side heat transfer coefficients to tune the heat exchanger performance to manufacturer or measured specifications. Alternatively, the heat transfer area can be adjusted to match the specified performance. Fouling factors and tube plugging are applied when conservative.

5.4.2.1.5 LOCA Mass and Energy Release to Containment

During a LOCA event, most of the vessel water will be displaced by the steam generated by flashing. The vessel is then refilled by the accumulators and the high and low pressure injection systems. GOTHIC is not suitable for modeling the refill period because it involves quenching of the fuel rods where film boiling conditions may exist. Current versions of GOTHIC do not have models for quenching and film boiling. Therefore, for the blowdown, refill and reflood stages, the mass and energy release rates are obtained from Westinghouse LOCA analysis. The Westinghouse release data includes the water from the ECCS accumulators, but the nitrogen release to containment is modeled separately in GOTHIC.

The LOCA mass and energy release rates are input to GOTHIC for the blowdown and reflood periods of the design basis LOCAs. The calculation of these release rates is described in Section 5.4.1. The mass and energy release rates used in the containment peak pressure, containment depressurization, and NPSH analyses for the RS and LSHI pumps are provided in this section. The mass and energy release rates for the DEHLG through the end of reflood are tabulated in Table 5.4-6 for maximum two-train safety injection flow. The mass and energy release rates for the reactor coolant DEPSG through the end of reflood are provided in Table 5.4-7 for maximum single-train safety injection flow.

At the end of reflood, the core has been recovered with water and the ECCS continues to supply water to the vessel. Residual stored energy and decay heat comes from the fuel rods. Stored energy in the vessel and primary system metal will also be gradually released to the injection water and released to the containment via steaming through the core or spillage into the containment sump. In addition, there may be some buoyancy-driven circulation through the intact steam generator loops that will remove stored energy from the steam generator metal and the water on the secondary side. Depending on the location of the break, the two-phase mixture in the vessel may pass through the steam generator on the broken loop and acquire heat from the stored energy in the secondary system. For these conditions, GOTHIC is capable of calculating the mass and energy release from the break into containment.

The GOTHIC long-term mass and energy release accounts for the transfer of the decay heat and the stored energy in the primary and secondary systems to the containment after the end of reflood. The energy for each source term is acquired at the end of reflood from the Westinghouse mass and energy release analysis. The rate of energy release is determined by a simplified GOTHIC RCS model that is coupled to the containment volume. Thus, the flow from the vessel to the containment is dependent on the GOTHIC-calculated containment pressure.

Lumped volumes are used for the vessel, downcomer, cold legs, steam generator secondary side, up-flow steam generator tubes and down-flow steam generator tubes. Separate sets of loop and secondary system volumes are used for the intact and broken loops with the connections between the broken loop and containment as necessary for the modeled break location. The Westinghouse calculated mass and energy inventory at the end of reflood establishes the liquid volume fractions and the fluid temperatures in the primary and secondary systems.

The primary and secondary system geometries, including primary system resistances, are consistent with the models used for non-LOCA accident analyses. In order to predict the natural circulation through the intact loops and the correct water level in the vessel and downcomer, the volumes are modeled with the correct elevations and heights. The vessel height may be adjusted so that the water and steam inventory at the end of reflood matches the vendor's boundary conditions, but this correction does not affect the hydraulic analysis.

Safety injection fluid is added to the downcomer volume (for the intact cold legs) and the broken loop cold leg. In both locations, the SI fluid mixes with the resident fluid and any vapor from the intact SGs. The SI flow is taken from the RWST until a low-low level is reached, at which time the SI fluid is taken from the containment sump.

A thermal conductor is used to model the transfer of energy stored in the shell side of the steam generator to the SG secondary fluid. The initial temperature is set to match the available stored energy specified at the end of reflood by the fuel vendor analysis. The up flow and down flow tubes on the steam generators are modeled separately with thermal conductors. This allows for the possibility of boiling in the up flow tubes and superheating of the steam in the down flow tubes. The heat transfer from the secondary side to the primary side is modeled using conductors with the inside connected to the primary system tube volumes. The Film heat transfer option is used on both sides of the tube. This option automatically accounts for heat transfer to the liquid or vapor phase as appropriate and includes boiling heat transfer modes.

5.4.2.1.6 NPSH Available

NPSHa (net positive suction head available) is the difference between the fluid stagnation pressure and the saturation pressure at the pump intake. To calculate NPSHa for a given pump, the GOTHIC containment model includes a separate small volume for the pump suction. The volume elevation and height are set so that the mid-elevation of the volume is at the elevation of the pump first-stage impeller centerline. The volume pressure (with some adjustments for sump depth) can then be used in the NPSHa calculation. The temperature in the suction volume provides the saturation pressure. The junction representing piping between the sump and the suction volume reflects the friction and form pressure drop between the sump and the pump suction. The pump suction volume also allows accurate modeling of the mixing of cold water that is injected into the suction of the RS pumps.

The single volume GOTHIC model does not account for geometry details of the sump or the liquid that is held up in other parts of the containment. GOTHIC does calculate the total amount of liquid in the containment. A correlation is used to define the sump depth or liquid level as a function of the water volume in the containment. The correlation accounts for the sump geometry variation with water depth and accounts for the holdup of water in other parts of the containment.

Worst case conditions for NPSHa depend on the time that the pumps take suction from the sump. Therefore, the parameter settings that minimize NPSHa may vary depending on the timing for the operation of the pumps. In general, settings that reduce containment pressure and increase the sump water temperature reduce the NPSHa.

The water in the sump comes from three sources: direct deposit of mass from the break, condensate from the conductors, and spray drops. The drops from the blowdown will be very small and at the saturation temperature at the containment steam partial pressure when they enter the sump. After the blowdown, the spillage water from the vessel is directly put in the sump with no heat transfer to the atmosphere or walls and equipment in the containment. This is a conservative approach for NPSH analysis. The condensate is generated at the saturation temperature at the steam partial pressure and added directly to the sump. The heat transfer between the conductors and the condensate on the way to the sump is conservatively neglected. Heat and mass transfer at the sump surface is allowed. GOTHIC's model for heat and mass transfer at a pool is in good agreement with experimental data. For NPSH analysis, the liquid temperature is greater than the vapor temperature for most of the event, so a minimum pool area is specified to minimize evaporation. With this overall approach, the predicted sump temperature is conservatively high for the duration of the simulation.

The following adjustments are made to ensure a conservative calculation of NPSHa:

1. The heat and mass transfer to the containment heat sinks are expected to be under-predicted using the Direct heat transfer model. This is non-conservative for NPSH analysis. A multiplier of 1.2 applied to the heat transfer coefficient was shown to provide adequate conservatism in the calculation.

2. All of the spray water is injected as droplets into the containment atmosphere (nozzle spray flow fraction of 1). Analyses are performed using the largest Sauter droplet size. A confirmatory analysis is performed by reducing the Sauter diameter by 2, which sufficiently covers code and spray performance uncertainty (i.e., variation in nozzle design and orientation, nozzle flow rate and different header elevations) without creating drops too small that may cause excess droplet holdup in the atmosphere. NPSH analyses are relatively insensitive over this range of droplet size, and the two cases together confirm that the effect of sprays on reducing containment pressure is maximized. The minimum NPSHa is reported from the case that provides the smaller NPSHa.

3. A conservative water holdup volume is subtracted from the containment liquid volume to reduce the sump water height.

4. The upper limit on containment free volume is used.

5. The minimum containment air pressure is used.

6. Conservative assumptions for spray and other system parameters are used in accordance with plant-specific sensitivity studies.

A modification of the NPSH methodology used for developing component design inputs was submitted to the NRC in Reference 10. This alternate methodology can be used for NPSH and LOCA analyses that develop design inputs for component design, such as determination of margin for sump strainer design. The NRC approved the alternate methodology in Reference 11, thus confirming that it can be used for the intended application stated in Reference 10.

5.4.2.1.7 LOCA - Containment Pressure and Temperature Results

The containment LOCA analysis is performed for the two limiting pipe break locations (DEPSG and DEHLG) discussed in Section 5.4.1. The DEPSG is most limiting for long-term containment temperature and pressure response. Table 5.4-7 provides the DEPSG mass and energy instantaneous releases as well as the releases for the reflood phase. The DEPSG data is presented for two break paths. Break path 1 represents the mass and energy exiting from the SG side of the break. Break path 2 is the mass and energy exiting from the pump side of the break.

Containment analysis parameters are listed in Table 5.4-17. The RS pumps start with individual delay times on 60% RWST level coincident with a CLS High High containment pressure signal.

The results of the containment pressure analysis are tabulated in Table 5.4-11. The initial containment conditions which yield the highest peak calculated containment pressure are the maximum pressure, temperature, and relative humidity, and are given in Table 5.4-10. The containment pressure and temperature transients for the hot leg double-ended guillotine are given on Figures 5.4-1 and 5.4-2, respectively.

The maximum peak containment pressure occurs after a DEHLG. As shown in Table 5.4-11, the calculated containment pressure is below the containment design pressure of 45 psig. The DEHLG is the design basis accident (DBA) for the containment structure (containment integrity DBA).

A single failure analysis is not necessary for the peak containment pressure evaluation since the peak pressure for each break case analyzed occurs early in the transient before any of the engineered safety feature (ESF) systems start.

The results of the containment depressurization analysis are tabulated in Table 5.4-12. Only a DEPSG is considered for the containment depressurization analysis since, as described earlier, this break produces the highest energy flow rates during the post-blowdown period. The containment pressure is less than 1.0 psig within one hour and less than 0 psig within 4 hours as shown in Table 5.4-12. The SI flow is based on a minimum estimate. This minimizes the credit for steam condensation due to steam/water mixing.

The initial conditions which result in the maximum depressurization time are as follows:

1. Initial containment pressure of 12.52 psia.
2. Initial containment temperature of 125°F.
3. Initial containment relative humidity of 100%.
4. Service water (ultimate heat sink) temperature of 100°F.
5. Refueling water storage tank temperature of 45°F.

The initial conditions which result in the maximum time to approach the four hour subatmospheric requirement are as follows:

1. Initial containment pressure of 10.97 psia
2. Initial containment temperature of 75°F
3. Initial containment humidity of 100%
4. Service water (ultimate heat sink) temperature of 100°F
5. Refueling water storage tank temperature of 45°F

These limiting values are consistent with the Technical Specifications. Instrumentation uncertainties for these parameters have been included in the safety analysis.

The highest depressurization peak pressure may result from service water temperatures less than the TS maximum.

A chronology of events for this DEPSG with minimum ESF for both sets of initial conditions described in this section is given in Table 5.4-13.

Representative results for containment pressure, vapor temperature, sump water temperature and RS heat exchanger duty are shown in Figures 5.4-3, 5.4-4 (illustrates containment vapor and liquid temperature) and 5.4-5, respectively. These results are based on the initial conditions which result in the maximum time to approach the four hour subatmospheric requirement as described above.

For the depressurization analysis, only the diesel generator failure is considered since all other single failures result in increased containment heat removal capability as compared to this single failure.

The results of the LOCA analysis are reported in Tables 5.4-11 and 5.4-12.

5.4.3 MSLB Containment Pressure and Temperature Response

Surry did not previously have an explicit MSLB containment response analysis. The containment response was bounded by the Beaver Valley Unit 1 MSLB analysis. Reference 9 made the comparison and described the conservatism in the Beaver Valley Unit 1 MSLB containment pressurization analysis versus Surry. MSLB analysis has been performed for Surry using GOTHIC. The GOTHIC model is as described in Section 5.4 for LOCA analysis with the exception of the mass and energy release data. GOTHIC analysis inputs are provided in Table 5.4-17.

5.4.3.1 **MSLB Mass and Energy Release to Containment**

For MSLB, the mass and energy release data is obtained from Westinghouse using NRC-approved methods. Surry does not have explicit mass and energy release data from Westinghouse. The North Anna MSLB mass and energy release data from Westinghouse was confirmed to be conservative for Surry and was applied for this analysis. The break junction uses 100-micron droplets for entrained liquid release. A range of break sizes from small split breaks to the largest double-ended break size is analyzed over the range of 0% to 114.3% of rated thermal power of 2587 MWt. Analysis of this range ensures that the most conservative results are predicted for containment pressure and temperature.

5.4.3.2 **MSLB Pressure and Temperature Analysis**

5.4.3.2.1 MSLB Peak Pressure Analysis

The maximum containment peak pressure occurs for the 1.4 ft^2 break at 0% power because it has the highest SG liquid mass and results in the largest mass release to the containment before the faulted SG dries out. Table 5.4-14 shows the results in peak pressure are less than the design limit of 59.7 psia. Table 5.4-15 shows the time sequence of events for the case with the proposed

TS air partial pressure limit of 11.3 psia. The atmosphere remains superheated for a very short time, returning to saturation within 10 seconds from the time of the break. The containment temperature and pressure peaks occur about 20 seconds before SG dryout, when condensation and the CS system overcome the steam release rate. Containment pressure drops rapidly once operator action terminates AFW to the faulted SG at 30 minutes, which stops the steam release to the containment.

SPS has cavitating venturis in the AFW lines leading to each SG that limit the flow rate to about 350 gpm. For the MSLB analyses, the mass release is 400 gpm after the faulted SG reaches dryout. This assumption provides a conservative, but reasonable long-term containment pressure and temperature response for SPS but does not affect the containment peak pressure and temperature, which occur earlier in the event.

The maximum initial air partial pressure is independent of SW temperature, because the RS system is not assumed to operate. Therefore, the maximum allowable TS air partial pressure is a constant line until the containment depressurization analyses limit the curve. In summary, a maximum operating containment air partial pressure of 11.3 psia ensures that the MSLB peak containment pressure will be less than the design limit of 59.7 psia.

5.4.3.2.2 MSLB Peak Temperature Analysis

The maximum peak temperature occurs for the 0.6 ft^2 break at 114.3% of 2587 MWt core power. This break has a saturated steam release at an enthalpy of about 1200 Btu/lbm for the entire accident. Minimum air partial pressure, maximum containment air temperature, and 0% humidity are conservative. Table 5.4-16 compares the analysis results. The increase in air pressure causes an increase in containment peak pressure but reduces the containment peak temperature. Figures 5.4-8 and 5.4-9 show the containment pressure and vapor temperature. The containment temperature peaks at 31 seconds when the break flow is reduced suddenly by the isolation of the non-faulted SGs from the steam line header. The vapor temperature decrease starting at 101 seconds is driven by the delivery of containment spray to the atmosphere. Containment pressure drops rapidly once operator action terminates AFW to the faulted SG at 30 minutes, which stops the steam release to the containment.

The analyses included an additional 1 ft^2 thermal conductor to determine a conservative containment liner temperature response in accordance with Section 3.3.3 of DOM-NAF-3A. The conductor used a 1.2 multiplier on the Direct/DLM heat transfer coefficient. The peak liner temperature for the proposed configuration was 251.1°F at 490 seconds, so the sustained superheat does not adversely affect the containment liner.

5.4 REFERENCES

1. USAEC, Division of Reactor Licensing 1972. *Safety Evaluation Report for Virginia Electric Power Company, Surry Power Station Units 1 and 2. Docket 50-280 and 50-281*.
2. *Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version,* WCAP-10325-P-A, May 1983 (Proprietary), WCAP-10326-A (Non-Proprietary).
3. *Westinghouse ECCS Evaluation Model - 1981 Version,* WCAP-9220-P-A, Rev. 1, February 1982 (Proprietary), WCAP-9221-A, Rev. 1 (Non-Proprietary).
4. Docket No. 50-315, *Amendment No. 126, Facility Operating License No. DPR-58 (TAC No. 7106), for D. C. Cook Nuclear Plant Unit 1,* June 9, 1989.
5. EPRI 294-2, *Mixing of Emergency Core Cooling Water with Steam; 1/3 Scale Test and Summary,* (WCAP-8423), Final Report June 1975.
6. *Westinghouse Mass and Energy Release Data For Containment Design,* WCAP-8264-P-A, Rev. 1, August 1975 (Proprietary), WCAP-8312-A (Non-Proprietary).
7. ANSI/ANS-5.1-1979, *American National Standard for Decay Heat Power in Light Water Reactors,* August 1979.
8. Topical Report DOM-NAF-3, Rev. 0.0-P-A, *GOTHIC Methodology For Analyzing the Response to Postulated Pipe Ruptures Inside Containment,* September 2006.
9. Letter from W.L. Stewart to Harold R. Denton (NRC), *Supplement to An Amendment to Operating Licenses DPR-32 and DPR-37 - Proposed Reduction in Boron Concentrations - Surry Power Station Units 1 and 2,* Serial No. 521B, November 30, 1983.
10. Letter from G.T. Bischof of Virginia Electric and Power Company to USNRC Document Control Desk, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, License Amendment Request, Alternative Containment Analysis Methodology,* Serial No. 07-0693, October 22, 2007.
11. Letter from USNRC to Virginia Electric and Power Company, *Safety Evaluation Report approving the Alternative Containment Analysis Methodology,* November 15, 2007.
12. Westinghouse Letter, *Surry LOCA Mass and Energy Reanalysis Report to Address Analysis Issues*, VRA-07-57, December 11, 2007.
13. PWROG-17034-P-A, *Evaluation of the WCAP-10325-P-A Westinghouse LOCA Mass & Energy Release Methodology*, March 2020.

Table 5.4-1
LOCA MASS & ENERGY RELEASE ANALYSIS SYSTEM PARAMETERS
INITIAL CONDITIONS

Parameters	Value
Core Thermal Power (100.38% of 2587 MWt)	2597 MWt
Reactor Coolant System Flowrate, per Loop	88,500 gpm
Vessel Outlet Temperature	605.6°F[a]
Core Inlet Temperature	540.4°F[a]
Vessel Average Temperature	573.0°F[a]
Initial Steam Generator Steam Pressure	785 psia
Steam Generator Design	Model 51F
Steam Generator Tube Plugging	0%
Total SG Dry Weight	691,000 lbm
SG Weight in Contact with Secondary Water	474,000 lbm
Initial SG Secondary-Side fluid	113,740 lbm
Assumed Maximum Containment Backpressure	59.7 psia
Accumulator	
Water Volume	1000 ft^3
N2 Cover Gas Pressure	600 psia
Temperature	105°F
Safety Injection Delay (includes time to reach pressure setpoint)	27.0 sec

a. These are nominal values; analysis value includes +4.0°F allowance for instrument error and deadband

Table 5.4-2
LOCA MASS & ENERGY RELEASE ANALYSIS SYSTEM PARAMETERS
CORE DECAY HEAT FRACTION

Time (sec)	Decay Heat (Btu/Btu)
10	0.052168
15	0.048917
20	0.047448
40	0.041405
60	0.038402
80	0.036324
100	0.03476
150	0.032104
200	0.03036
400	0.0266
600	0.024426
800	0.022885
1000	0.021666
1500	0.019429
2000	0.017851
4000	0.014334
6000	0.01263
8000	0.011588
10000	0.010856
15000	0.01013
20000	0.009368
40000	0.007784
60000	0.006976
80000	0.006439
100000	0.006034
150000	0.005336
200000	0.004859
400000	0.003781
600000	0.003212
800000	0.002844
1000000	0.002589
1500000	0.002175
2000000	0.001915
4000000	0.001356
6000000	0.00109
8000000	0.000924
10000000	0.000804

Table 5.4-3
LOCA MASS & ENERGY RELEASE ANALYSIS SAFETY INJECTION FLOW
MAXIMUM SI - SINGLE TRAIN

INJECTION MODE (REFLOOD PHASE)

RCS Pressure (psig)	Total Flow (gpm)
0	3978.7
40	3975.1
80	3649.0
120	2975.6
160	1513.2
175	753.9
200	515.2

INJECTION MODE (POST-REFLOOD PHASE)

RCS Pressure (psig)	Total Flow (gpm)
45	3839

RECIRCULATION MODE

RCS Pressure (psig)	Total Flow (gpm)
0	3330

Table 5.4-4
LOCA MASS & ENERGY RELEASE ANALYSIS SAFETY INJECTION FLOW
MINIMUM SI - SINGLE TRAIN

INJECTION MODE (REFLOOD PHASE)

RCS Pressure (psig)	Total Flow (gpm)
0	3303.6
40	3300.7
80	2771.0
120	1881.5
160	501.2
165	376.4
200	394.5

INJECTION MODE (POST-REFLOOD PHASE)

RCS Pressure (psig)	Total Flow (gpm)
45	3280

RECIRCULATION MODE

RCS Pressure (psig)	Total Flow (gpm)
0	2900.4

Table 5.4-5
LOCA MASS & ENERGY RELEASE ANALYSIS SAFETY INJECTION FLOW
MAXIMUM SI - TWO TRAIN

INJECTION MODE (REFLOOD PHASE)

RCS Pressure (psig)	Total Flow (gpm)
0	4784.2
40	4778.1
80	4772.1
120	4008.2
160	2439.0
175	1414.4
200	788.6

INJECTION MODE (POST-REFLOOD PHASE)

RCS Pressure (psig)	Total Flow (gpm)
45	4563

RECIRCULATION MODE

RCS Pressure (psig)	Total Flow (gpm)
0	4100

Table 5.4-6
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
0.00	97796.90	61319.60	627.01	97796.90	61319.60	627.01
0.05	44488.90	28002.40	629.42	26374.60	16393.20	621.55
0.10	44302.10	27906.20	629.91	25174.90	15676.20	622.69
0.15	39440.50	25074.10	635.74	24625.80	15322.90	622.23
0.20	32457.30	20820.80	641.48	23499.50	14590.50	620.89
0.25	31268.70	20074.80	642.01	21949.60	13577.10	618.56
0.30	31745.90	20358.30	641.29	20801.30	12808.40	615.75
0.35	31640.20	20286.90	641.17	20047.60	12272.10	612.15
0.40	31270.70	20055.50	641.35	19456.50	11831.30	608.09
0.45	31022.50	19902.20	641.54	19012.10	11481.90	603.93
0.50	30853.90	19801.80	641.79	18621.70	11167.20	599.69
0.55	30730.90	19734.60	642.17	18272.20	10883.10	595.61
0.60	30513.40	19612.70	642.76	18012.40	10658.60	591.74
0.65	30308.90	19502.00	643.44	17727.50	10424.00	588.01
0.70	30155.40	19424.10	644.13	17504.70	10233.10	584.59
0.75	30039.70	19372.90	644.91	17307.50	10061.50	581.34
0.80	29916.00	19320.10	645.81	17120.00	9899.30	578.23
0.85	29771.70	19256.40	646.80	16928.90	9740.80	575.39
0.90	29607.90	19183.10	647.90	16757.40	9597.00	572.70
0.95	29421.00	19096.60	649.08	16615.10	9474.00	570.20
1.00	29205.90	18994.20	650.35	16489.00	9362.90	567.83
1.05	28914.90	18843.50	651.69	16384.00	9266.80	565.60
1.10	28819.70	18825.50	653.22	16252.20	9158.20	563.51
1.15	28596.10	18729.30	654.96	16138.10	9062.30	561.55
1.20	28397.80	18648.90	656.70	16054.50	8985.80	559.71
1.25	28238.70	18594.40	658.47	15973.10	8912.10	557.94
1.30	28027.80	18502.30	660.14	15917.50	8855.00	556.31
1.35	27815.50	18402.70	661.60	15885.40	8812.20	554.74
1.40	27606.20	18300.00	662.89	15868.80	8778.70	553.21
1.45	27409.20	18201.70	664.07	15863.30	8752.80	551.76

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
1.50	27222.10	18108.40	665.21	15867.70	8733.20	550.38
1.55	27061.10	18032.90	666.38	15879.90	8718.60	549.03
1.60	26892.10	17952.70	667.58	15898.70	8708.40	547.74
1.65	26712.80	17866.40	668.83	15922.70	8701.30	546.47
1.70	26525.00	17773.60	670.07	15950.60	8697.60	545.28
1.75	26323.70	17670.70	671.28	15981.50	8696.00	544.13
1.80	26098.50	17550.30	672.46	16014.30	8696.40	543.04
1.85	25858.10	17417.60	673.58	16047.60	8697.70	541.99
1.90	25599.30	17270.50	674.65	16082.80	8700.60	540.99
1.95	25337.50	17119.20	675.65	16119.30	8705.10	540.04
2.00	25081.60	16970.10	676.60	16156.60	8711.20	539.17
2.05	24829.40	16823.20	677.55	16196.00	8718.80	538.33
2.10	24591.10	16685.20	678.51	16234.90	8727.20	537.56
2.15	24365.00	16555.70	679.49	16273.30	8736.10	536.84
2.20	24153.70	16436.40	680.49	16310.30	8745.00	536.16
2.25	23947.60	16320.40	681.50	16345.40	8753.70	535.55
2.30	23744.10	16204.80	682.48	16376.50	8761.00	534.97
2.35	23533.50	16082.00	683.37	16405.10	8767.80	534.46
2.40	23310.60	15947.70	684.14	16430.70	8773.60	0.00
2.45	23085.40	15808.00	0.00	16451.70	8777.80	0.00
2.50	22856.50	15663.00	685.28	16469.00	8780.40	533.15
2.55	22640.50	15524.60	685.70	16482.40	8781.90	532.80
2.60	22426.90	15387.00	686.10	16492.50	8781.90	532.48
2.65	22223.30	15255.20	686.45	16498.60	8780.50	532.20
2.70	22024.80	15125.80	686.76	16501.30	8777.60	531.93
2.75	21832.80	14999.40	687.01	16500.00	8773.30	531.72
2.80	21648.60	14877.10	687.21	16495.30	8767.60	531.52
2.85	21471.40	14758.60	687.36	16487.10	8760.30	531.34
2.90	21305.30	14646.70	687.47	16475.80	8751.90	531.20
2.95	21141.40	14535.40	687.53	16461.00	8741.90	531.07

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
3.00	20982.90	14425.80	687.50	16443.30	8730.80	530.96
3.05	20821.10	14311.70	687.37	16422.30	8718.30	530.88
3.10	20663.70	14198.20	687.11	16398.70	8704.70	530.82
3.15	20509.00	14084.80	686.76	16371.40	8689.30	530.76
3.20	20369.20	13981.00	686.38	16342.60	8673.50	530.73
3.25	20234.70	13880.30	685.97	16311.00	8656.50	530.72
3.30	20106.20	13782.60	685.49	16277.00	8638.40	530.71
3.35	19976.50	13682.60	684.93	16240.20	8619.10	530.73
3.40	19854.30	13586.20	684.30	16202.30	8599.40	530.75
3.45	19736.10	13491.10	683.57	16161.20	8578.20	530.79
3.50	19626.80	13401.30	682.81	16117.90	8556.10	530.84
3.55	19525.90	13317.20	682.03	16072.70	8533.10	530.91
3.60	19430.00	13236.00	681.21	16026.00	8509.60	530.99
3.65	19334.10	13153.10	680.31	15976.20	8484.50	531.07
3.70	19235.50	13067.10	679.32	15924.20	8458.50	531.17
3.75	19149.10	12987.80	678.25	15869.80	8431.40	531.29
3.80	19063.00	12908.60	677.15	15814.40	8403.80	531.40
3.85	18989.40	12837.20	676.02	15755.40	8374.60	531.54
3.90	18920.00	12768.20	674.85	15695.10	8344.70	531.68
3.95	18855.00	12700.80	673.60	15631.50	8313.40	531.84
4.00	18795.50	12636.50	672.32	15566.10	8281.10	532.00
4.10	18695.90	12518.70	669.60	15426.70	8212.70	532.37
4.20	18624.40	12418.70	666.80	15276.10	8138.60	532.77
4.30	18580.50	12333.00	663.76	15107.90	8055.50	533.20
4.40	18582.10	12274.00	660.53	14936.50	7971.10	533.67
4.50	18647.10	12257.60	657.35	14755.90	7882.20	534.17
4.60	18784.30	12281.60	653.82	14573.10	7792.10	534.69
4.70	19026.60	12349.10	649.04	14388.80	7701.50	535.24
4.80	13607.30	9894.10	727.12	14222.70	7621.00	535.83
4.90	14252.30	10254.80	719.52	14062.40	7543.50	536.43

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
5.00	14424.20	10285.60	713.08	13866.70	7446.60	537.01
5.10	14605.20	10262.10	702.63	13630.90	7327.90	537.59
5.20	14886.20	10353.60	695.52	13372.30	7196.90	538.19
5.30	14977.50	10337.20	690.18	13123.60	7071.30	538.82
5.40	15118.00	10351.70	684.73	12888.60	6953.50	539.51
5.50	15253.20	10361.80	679.32	12662.90	6840.80	540.22
5.60	15343.10	10337.90	673.78	12444.40	6732.20	540.98
5.70	15482.50	10371.60	669.89	12228.00	6624.50	541.75
5.80	15582.80	10359.70	664.82	11999.20	6510.30	542.56
5.90	15691.40	10369.20	660.82	11784.20	6402.90	543.35
6.00	15806.00	10384.30	656.98	11561.40	6291.20	544.16
6.10	15930.80	10377.40	651.40	11345.20	6182.40	544.94
6.20	16035.90	10422.40	649.94	11130.10	6074.10	545.74
6.30	15700.70	10207.60	650.14	10923.10	5969.50	546.50
6.40	15884.50	10265.40	646.25	10720.30	5866.80	547.26
6.50	16018.80	10297.30	642.83	10519.20	5764.50	548.00
6.60	16143.60	10328.00	639.76	10322.40	5664.20	548.73
6.70	16262.90	10359.10	636.98	10129.00	5565.20	549.43
6.80	16383.70	10392.70	634.33	9941.40	5469.10	550.13
6.90	16511.10	10431.50	631.79	9763.80	5378.00	550.81
7.00	16622.80	10462.20	629.39	9589.30	5288.30	551.48
7.10	16736.10	10497.00	627.21	9423.80	5203.20	552.13
7.20	16915.30	10567.20	624.71	9258.20	5117.80	552.79
7.30	17036.60	10605.50	622.51	9099.70	5036.10	553.44
7.40	17221.10	10679.40	620.13	8943.40	4955.50	554.10
7.50	17464.70	10781.90	617.35	8792.40	4877.80	554.77
7.60	17776.00	10916.80	614.13	8647.20	4803.10	555.45
7.70	17969.50	11012.40	612.84	8507.70	4731.20	556.11
7.80	17881.00	10938.90	611.76	8367.00	4658.80	556.81
7.90	17784.70	10860.80	610.68	8232.10	4589.40	557.50

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
8.00	17644.80	10756.00	609.58	8098.80	4520.80	558.21
8.10	17477.70	10640.30	608.79	7967.80	4453.40	558.92
8.20	16639.10	10196.20	612.79	7837.90	4386.80	559.69
8.30	15243.20	9447.20	619.76	7708.80	4320.50	560.46
8.40	14863.10	9234.20	621.28	7585.40	4257.20	561.24
8.50	14843.50	9205.90	620.20	7463.80	4195.20	562.07
8.60	14873.80	9206.00	618.94	7342.50	4133.30	562.93
8.70	14912.50	9214.00	617.87	7225.00	4073.60	563.82
8.80	14950.90	9223.80	616.94	7110.90	4015.90	564.75
8.90	14938.20	9205.50	616.24	7002.30	3961.30	565.71
9.00	14894.00	9171.30	615.77	6897.30	3908.80	566.71
9.10	14834.20	9128.90	615.40	6795.30	3857.70	567.70
9.20	14756.40	9075.70	615.03	6692.10	3805.90	568.72
9.30	14654.70	9009.00	614.75	6591.70	3755.50	569.73
9.40	14514.20	8921.30	614.66	6491.40	3705.30	570.80
9.50	14327.20	8809.30	614.87	6393.60	3656.60	571.92
9.60	14104.00	8679.20	615.37	6298.00	3608.90	573.02
9.70	13867.90	8542.90	616.02	6204.40	3562.40	574.17
9.80	13636.30	8408.90	616.66	6108.40	3514.70	575.39
9.90	13438.50	8293.70	617.16	6017.10	3469.80	576.66
10.00	13263.90	8190.60	617.51	5925.70	3424.90	577.97
10.10	13098.80	8092.70	617.82	5833.40	3379.80	579.39
10.20	12945.80	8002.30	618.14	5745.60	3336.90	580.77
10.30	12786.10	7908.90	618.55	5656.40	3293.70	582.30
10.40	12630.00	7818.40	619.03	5571.70	3252.90	583.83
10.50	12467.60	7725.10	619.61	5487.20	3212.20	585.40
10.60	12302.20	7630.70	620.27	5405.40	3173.00	587.01
10.70	12132.30	7534.50	621.03	5323.40	3133.80	588.68
10.80	11955.90	7435.50	621.91	5241.50	3094.80	590.44
10.90	11782.80	7338.60	622.82	5162.20	3057.10	592.21

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
11.00	11608.10	7241.60	623.84	5083.80	3020.00	594.04
11.10	11439.50	7148.50	624.90	5008.00	2984.30	595.91
11.20	11269.20	7054.80	626.02	4932.70	2949.00	597.85
11.30	11096.90	6960.60	627.26	4856.50	2913.20	599.86
11.40	10932.60	6871.60	628.54	4784.80	2879.80	601.86
11.50	10762.70	6780.00	629.95	4710.20	2845.10	604.03
11.60	10602.30	6694.60	631.43	4641.40	2813.40	606.15
11.70	10434.20	6605.20	633.03	4570.70	2780.80	608.40
11.80	10268.60	6517.80	634.73	4501.80	2749.10	610.67
11.90	10091.70	6424.80	636.64	4431.50	2716.70	613.04
12.00	9909.40	6329.80	638.77	4362.90	2685.20	615.46
12.10	9719.60	6232.00	641.18	4293.90	2653.50	617.97
12.20	9515.50	6128.40	644.04	4221.10	2620.00	620.69
12.30	9305.20	6022.70	647.24	4146.90	2585.80	623.55
12.40	9085.40	5914.00	650.93	4069.60	2550.40	626.70
12.50	8858.80	5803.80	655.15	3988.50	2513.50	630.19
12.60	8626.30	5693.00	659.96	3903.40	2475.40	634.17
12.70	8396.50	5585.60	665.23	3815.90	2436.60	638.54
12.80	8164.40	5480.20	671.23	3723.80	2396.70	643.62
12.90	7933.60	5379.20	678.03	3626.70	2355.40	649.46
13.00	7705.40	5282.00	685.49	3525.70	2313.00	656.04
13.10	7480.20	5190.00	693.83	3421.60	2270.20	663.49
13.20	7258.50	5102.00	702.90	3316.20	2227.30	671.64
13.30	7038.40	5016.60	712.75	3210.30	2184.70	680.53
13.40	6816.70	4932.30	723.56	3103.20	2141.80	690.19
13.50	6594.80	4850.30	735.47	2995.10	2098.60	700.68
13.60	6379.70	4769.30	747.57	2892.90	2056.90	711.02
13.70	6162.20	4687.90	760.75	2791.30	2015.00	721.89
13.80	5946.00	4605.30	774.52	2695.10	1974.50	732.63
13.90	5735.40	4523.10	788.63	2605.50	1935.50	742.85

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
14.00	5525.20	4441.00	803.77	2522.00	1898.40	752.74
14.10	5320.70	4362.40	819.89	2443.20	1861.90	762.07
14.20	5120.90	4281.60	836.10	2371.90	1827.70	770.56
14.30	4918.70	4196.00	853.07	2307.30	1795.60	778.23
14.40	4720.00	4111.70	871.12	2249.40	1765.80	785.01
14.50	4518.50	4027.30	891.29	2195.60	1737.00	791.13
14.60	4302.80	3942.10	916.17	2147.00	1710.20	796.55
14.70	4045.90	3823.60	945.06	2102.80	1685.30	801.46
14.80	3784.80	3662.80	967.77	2061.60	1661.70	806.02
14.90	3563.70	3503.90	983.22	2023.00	1639.80	810.58
15.00	3396.50	3366.60	991.20	1986.50	1619.00	815.00
15.10	3258.30	3253.70	998.59	1951.70	1599.20	819.39
15.20	3114.70	3144.50	1009.57	1918.70	1580.60	823.79
15.30	2973.40	3041.90	1023.04	1885.20	1561.60	828.35
15.40	2827.40	2941.90	1040.50	1853.10	1543.80	833.09
15.50	2678.30	2841.30	1060.86	1820.20	1525.90	838.31
15.60	2526.10	2742.80	1085.78	1785.90	1508.10	844.45
15.70	2371.10	2640.80	1113.74	1750.90	1491.40	851.79
15.80	2225.40	2538.60	1140.74	1714.80	1475.60	860.51
15.90	2099.00	2439.30	1162.12	1676.30	1459.80	870.85
16.00	1995.10	2350.60	1178.19	1636.20	1444.50	882.84
16.10	1912.90	2277.70	1190.71	1594.40	1429.20	896.39
16.20	1879.50	2251.60	1197.98	1551.00	1413.50	911.35
16.30	1810.70	2182.20	1205.17	1506.20	1396.80	927.37
16.40	1754.80	2119.90	1208.06	1464.40	1382.50	944.07
16.50	1708.20	2071.90	1212.91	1422.20	1370.30	963.51
16.60	1651.50	2007.10	1215.32	1378.70	1355.10	982.88
16.70	1593.00	1943.30	1219.90	1339.40	1339.90	1000.37
16.80	1530.90	1874.30	1224.31	1302.50	1325.30	1017.50
16.90	1469.10	1804.50	1228.30	1269.20	1314.60	1035.77

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
17.00	1410.30	1737.20	1231.79	1234.70	1301.60	1054.18
17.10	1356.40	1674.70	1234.67	1204.80	1288.00	1069.06
17.20	1317.00	1628.20	1236.29	1178.30	1274.50	1081.64
17.30	1279.60	1580.40	1235.07	1155.00	1261.40	1092.12
17.40	1238.60	1529.30	1234.70	1134.30	1248.40	1100.59
17.50	1199.50	1483.00	1236.35	1115.20	1235.40	1107.78
17.60	1142.00	1413.10	1237.39	1097.30	1223.30	1114.83
17.70	1097.10	1365.60	1244.74	1080.30	1213.20	1123.02
17.80	1057.20	1318.60	1247.26	1058.30	1203.10	1136.82
17.90	1015.60	1266.50	1247.05	1031.90	1190.80	1153.99
18.00	982.80	1224.60	1246.03	1003.60	1178.30	1174.07
18.10	946.40	1178.90	1245.67	953.50	1142.00	1197.69
18.20	912.70	1142.10	1251.34	900.50	1092.20	1212.88
18.30	871.20	1093.10	1254.71	848.70	1036.90	1221.75
18.40	826.20	1034.60	1252.24	801.50	982.70	1226.08
18.50	800.00	1003.00	1253.75	756.20	929.20	1228.78
18.60	757.70	950.60	1254.59	716.90	882.00	1230.30
18.70	722.70	907.50	1255.71	672.50	828.00	1231.23
18.80	696.40	874.70	1256.03	601.20	740.40	1231.54
18.90	663.10	832.90	1256.07	514.50	634.40	1233.04
19.00	637.70	801.00	1256.08	453.80	560.90	1236.01
19.10	618.20	776.40	1255.90	380.30	470.50	1237.18
19.20	598.20	751.20	1255.77	322.40	399.90	1240.38
19.30	580.30	728.50	1255.39	281.40	349.90	1243.43
19.40	565.30	709.40	1254.91	247.90	308.90	1246.07
19.50	551.20	691.10	1253.81	231.90	289.50	1248.38
19.60	536.20	672.20	1253.64	232.80	291.10	1250.43
19.70	510.70	639.50	1252.20	198.30	247.80	1249.62
19.80	494.60	617.00	1247.47	105.20	131.80	1252.85
19.90	499.80	622.30	1245.10	0.00	0.00	0.00

Table 5.4-6 (CONTINUED)
DEHLG, MAXIMUM SI TWO TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
20.00	298.80	376.20	1259.04	0.00	0.00	0.00
20.10	66.40	85.30	1284.64	0.00	0.00	0.00
20.20	0.00	0.00	0.00	71.80	93.50	1302.23
20.30	0.00	0.00	0.00	0.00	0.00	0.00
20.5	0	0.00	0.00	0.00	0.00	0.00
20.6	0	0.00	0.00	0.00	0.00	0.00
20.8	574.6	151.30	263.31	0.00	0.00	0.00
20.9	349.2	197.30	565.01	0.00	0.00	0.00
23.4	1094.8	354.20	323.53	0.00	0.00	0.00
26.6	1692	463.51	273.94	0.00	0.00	0.00
29.3	1918.1	502.29	261.87	1799.7	136.90	76.07
33.4	1852.1	471.80	254.74	2894.5	192.60	66.54
45.3	1650.1	430.00	260.59	2011	129.41	64.35
46	1641.3	363.60	221.53	0.00	0.00	0.00
50	1376	311.80	226.6	0.00	0.00	0.00
57.7	866	264.10	304.97	0.00	0.00	0.00
88	420.8	218.80	519.96	0.00	0.00	0.00
100	407	214.60	527.27	0.00	0.00	0.00
115.3	395.6	210.60	532.36	0.00	0.00	0.00

a. Break Path No. 1 refers to the mass and energy exiting from the reactor vessel side of the break.
b. Break Path No. 2 refers to the mass and energy exiting from the SG side of the break.

Table 5.4-7
DEPSG, MINIMUM SI SINGLE TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
0.00	147896.10	79856.5	539.95	147896.10	79856.5	539.95
0.10	39713.70	21300.9	536.36	20013.90	10695.1	534.38
0.20	40315.50	21753.3	539.58	21993.10	11761.8	534.80
0.30	41093.10	22346.5	543.80	22177.50	11872.6	535.34
0.40	43232.40	23723.9	548.75	21755.60	11658.1	535.87
0.50	42782.70	23719.9	554.43	20914.60	11215.7	536.26
0.70	43347.40	24527.3	565.83	19421.00	10422.6	536.67
0.90	42430.10	24426.6	575.69	18386.20	9871.2	536.88
1.40	38047.10	22833.5	600.14	17469.40	9384	537.17
1.90	32587.80	20573.9	631.34	17203.40	9237.7	536.97
2.40	26788.20	17811.7	664.91	16740.80	8986.7	536.81
2.60	21346.80	14405.3	674.82	16469.90	8841.1	536.80
2.70	19921.30	13561.6	680.76	16137.70	8662.5	536.79
2.80	19578.40	13416.1	685.25	15901.80	8536.6	536.83
3.00	17642.40	12167.1	689.65	15474.90	8308.9	536.93
3.30	15505.90	10780.7	695.26	14881.20	7994.1	537.19
3.60	13835.20	9688.4	700.27	14377.10	7728.2	537.54
4.20	11874.60	8402.7	707.62	13449.60	7239.7	538.28
5.00	10422.10	7381.8	708.28	12320.00	6642.2	539.14
5.40	10019.40	7044.7	703.11	13061.30	7047.3	539.56
5.80	10327.70	7242.9	701.31	12624.70	6816.1	539.90
6.20	8542.20	6757.4	791.06	12130.10	6553.3	540.25
6.40	8097.20	6512	804.23	11957.80	6462.8	540.47
7.00	8215.30	6324.4	769.83	11673.70	6316.4	541.08
7.80	9041.50	6384.4	706.12	11048.00	5972.3	540.58
8.40	9227.10	6239	676.16	10626.70	5741.2	540.26
10.60	6898.70	5030.9	729.25	9319.50	5030.2	539.75
11.40	6208.00	4696.1	756.46	8803.20	4750.7	539.66
13.60	4872.30	3881.1	796.56	7388.60	3988.2	539.78
14.20	4488.80	3608	803.78	6848.50	3597.5	525.30
14.40	4360.70	3513	805.60	7342.20	3776.3	514.33
14.80	4151.20	3349.2	806.80	6083.70	3003.3	493.66
15.20	3944.60	3212.1	814.30	11223.70	5460	486.47
15.40	3774.30	3120.5	826.78	9121.60	4461.5	489.11

Table 5.4-7 (CONTINUED)
DEPSG, MINIMUM SI SINGLE TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
15.60	3710.30	3136	845.21	5303.40	2586.9	487.78
15.80	3726.10	3184.7	854.70	5139.50	2397.4	466.47
16.00	3574.00	3135.3	877.25	11125.80	5090.8	457.57
16.40	3252.00	3084.5	948.49	4818.10	2276.2	472.43
16.60	3205.30	3119.5	973.23	4110.80	1872.6	455.53
16.80	3034.10	3078.5	1014.63	6391.90	2715.1	424.77
17.00	2718.90	2921.3	1074.44	8144.90	3472.7	426.36
17.20	2410.40	2781.5	1153.96	5522.90	2371.9	429.47
17.40	2200.70	2659.1	1208.30	4366.60	1882.7	431.16
17.80	1844.60	2273.6	1232.57	3174.80	1316.6	414.70
18.20	1485.10	1841.7	1240.12	4472.10	1677.7	375.15
19.20	866.70	1084.4	1251.18	3306.50	1137.1	343.90
20.20	460.20	578.2	1256.41	1917.70	585.1	305.11
20.60	395.50	497.6	1258.15	1276.70	372.3	291.61
21.20	282.90	356.4	1259.81	0.00	0	0.00
22.60	0.00	0	0.00	0.00	0	0.00
23.50	0.00	0	0.00	0.00	0	0.00
23.60	44.50	52.4	1177.53	0.00	0	0.00
23.70	25.30	29.8	1177.87	0.00	0	0.00
24.20	51.70	60.9	1177.95	0.00	0	0.00
25.00	79.50	93.6	1177.36	0.00	0	0.00
26.60	118.80	139.9	1177.61	0.00	0	0.00
27.60	137.90	162.5	1178.39	0.00	0	0.00
28.60	211.40	249.5	1180.23	1667.90	178.9	107.26
29.10	388.60	460	1183.74	3898.50	440.2	112.92
29.70	424.10	502.4	1184.63	4232.10	493.8	116.68
30.70	446.00	528.5	1184.98	4460.00	498.2	111.70
32.70	427.50	506.4	1184.56	4282.20	481.9	112.54
34.70	410.10	485.6	1184.10	4111.90	465.6	113.23
35.70	401.90	475.9	1184.13	4030.80	457.9	113.60
37.70	386.70	457.7	1183.60	3877.20	443.1	114.28
39.70	372.80	441.1	1183.21	3734.30	429.4	114.99
41.70	360.00	425.9	1183.06	3601.20	416.7	115.71
43.70	348.20	411.9	1182.94	3476.90	404.8	116.43

Table 5.4-7 (CONTINUED)
DEPSG, MINIMUM SI SINGLE TRAIN
MASS AND ENERGY RELEASES FOR CONTAINMENT ANALYSIS

	Break Path No. 1[a]			Break Path No. 2[b]		
Time	Flow	Energy	Enthalpy	Flow	Energy	Enthalpy
Seconds	LBM/Sec	Thousands BTU/Sec	BTU/LBM	LBM/Sec	Thousands BTU/Sec	BTU/LBM
44.70	342.70	405.3	1182.67	3417.70	399.1	116.77
46.70	332.20	392.8	1182.42	3304.70	388.3	117.50
47.80	243.70	287.7	1180.55	236.70	109.6	463.03
48.80	251.20	296.6	1180.73	239.60	113.4	473.29
50.80	244.70	288.8	1180.22	237.10	110.2	464.78
56.80	226.50	267.3	1180.13	230.40	101.4	440.10
60.80	215.20	253.9	1179.83	226.20	96	424.40
68.80	195.50	230.6	1179.54	219.10	86.8	396.17
69.80	193.30	227.9	1179.00	218.30	85.7	392.58
73.80	184.60	217.7	1179.31	215.30	81.8	379.93
81.80	169.30	199.6	1178.97	210.00	75	357.14
89.80	156.20	184.1	1178.62	205.60	69.4	337.55
90.30	155.50	183.2	1178.14	205.30	69.1	336.58
97.80	145.30	171.3	1178.94	202.00	64.8	320.79
105.80	136.40	160.7	1178.15	199.20	61.2	307.23
113.80	129.30	152.3	1177.88	196.90	58.4	296.60
121.80	123.70	145.8	1178.66	195.20	56.2	287.91
129.80	119.60	140.9	1178.09	193.90	54.5	281.07
137.80	116.50	137.3	1178.54	192.90	53.3	276.31
139.80	116.10	136.7	1177.43	192.80	53.1	275.41
145.80	115.10	135.7	1178.97	195.00	53.3	273.33
149.80	114.60	135	1178.01	198.90	54	271.49
153.80	113.80	134.1	1178.38	204.60	55.1	269.31
157.80	112.90	133	1178.03	211.70	56.5	266.89
165.80	109.90	129.4	1177.43	229.00	59.8	261.14
173.80	109.40	128.9	1178.24	244.20	62.3	255.12
175.80	109.20	128.6	1177.66	247.60	62.8	253.63
183.80	107.90	127.1	1177.94	259.40	63.9	246.34
191.80	106.20	125.1	1177.97	268.70	64.1	238.56
199.80	104.10	122.7	1178.67	276.00	63.7	230.80
200.70	103.90	122.4	1178.06	276.70	63.6	229.85

a. Mass and energy exiting the SG side of the break.
b. Mass and energy exiting the pump side of the break.

Table 5.4-8
THERMOPHYSICAL PROPERTIES OF PASSIVE HEAT SINK MATERIALS

Material	Thermal Conductivity (Btu/hr/ft/°F)	Specific Heat Capacity (Btu/lb_m/°F)	Density (lb_m/ft^3)
Concrete	1.0	0.156	142
Stainless Steel	9.4	0.12	501
Carbon Steel	27	0.10	490
Paint	0.125	0.10	110

Table 5.4-9
PASSIVE HEAT SINKS

TC #	Description	Surface Area, ft^2	Thickness, inch
1	Interior Concrete Wall 1	7740	6.0 [a]
2	Interior Concrete Wall 2	57,435	12.0 [a]
3	Interior Concrete Wall 3	51,064	18.0 [a]
4	Interior Concrete Wall 4	10,691	24.0 [a]
5	Interior Concrete Wall 5	8673	27.0 [a]
6	Interior Concrete Wall 6	3353	36.0 [a]
7	Cont Wall Below Grade b	20,108	54.375 [a]
8	Cont Wall Above Grade [b]	24,576	54.375 [a]
9	Containment Dome [b]	24,656	30.5 [a]
10	Containment Floor	11,757	146.65 [a]
11	Stainless Steel Group 1	7180	0.25
12	Stainless Steel Group 2	11,290	0.42
13	Stainless Steel Group 3	488	1.53
14	Galvanized Metal	86,459	0.066 [a]
15	Carbon Steel Group 1	7192	0.236 [a]
16	Carbon Steel Group 2	66,345	0.439 [a]
17	Carbon Steel Group 3	7454	0.906 [a]
18	Carbon Steel Group 4 [c]	2414	1.70 [a]
19	Carbon Steel Group 5	7000	2.90 [a]
29	Accumulators [c]	1276	1.0

a. Includes 0.006-inch paint layer.
b. The containment walls and dome include a liner-concrete gap conductance. The wall above grade and the dome use a constant HTC of 2.0 Btu/hr-ft^2-F and a specified temperature of 95°F on the outside.
c. The MSLB model accounts for the water in the accumulators as TC #29, different than the LOCA model (empty shell grouped with other carbon steel). TC #18 surface area of 2414 ft^2 is reduced by the accumulator surface area of 2073 ft^2 to 341 ft^2.

Table 5.4-10
CONTAINMENT LOCA ANALYSIS INITIAL CONDITIONS[a]

Air Partial Pressure	10.1 to 11.3 psia
Temperature	75 to 125°F
Relative Humidity	0 to 100 percent
RWST Temperature	45°F (maximum)
Service Water Temperature	25 to 100°F

a. Instrumentation uncertainties for these parameters have been included in the safety analysis.

Table 5.4-11
CONTAINMENT LOCA ANALYSIS PEAK PRESSURE RESULTS

Break Location	Hot Leg
Break Type	DEG
Peak Pressure	43.95 psig
Time of Peak Pressure	19.48 sec
Peak Vapor Temperature	273.3°F

Table 5.4-12
CONTAINMENT DEPRESSURIZATION RESULTS DEPSG

	Depressurization Time	Depressurization Peak Pressure
Single Failure	ESF Train	ESF Train
Initial Containment Conditions[a]		
Total Pressure	12.52 psia	10.97 psia
Temperature	125.0°F	75.0°F
Relative Humidity	100%	100%
Service Water Temperature	100.0°F	100.0°F
Depressurization Time (< 15.7 psia)	3110 sec	3038 sec
Depressurization Peak Pressure	0.34 psig	0.70 psig[b]
Depressurization Peak Pressure Time	5206 sec	5162 sec
Remains Subatmospheric Time	7732 sec	10,800 sec

a. Instrumentation uncertainties for these parameters have been included in the safety analysis.
b. Highest analysis value obtained for depressurization peak pressure.

Table 5.4-13
ACCIDENT CHRONOLOGY DEPSG, MINIMUM ESF

Time (sec)[a]		
Depressurization	Depressurization Peak	Event
2.1	2.3	CLS High High containment pressure
99.1	99.3	Containment spray delivers to containment
1861	1757	IRS spray delivered to containment
2012	1889	ORS spray delivered to containment
3110	3038	Containment pressure reaches 15.7 psia
3775	3734	Switchover to SI recirculation mode
4343	4304	Containment spray pumps stopped
5206	5162	Depressurization peak pressure occurs
7732	10,800	Containment pressure < 14.7 psia permanently

a. Times are analysis values obtained for initial conditions given in Table 5.4-12. These time values are approximate.

Table 5.4-14
MSLB CONTAINMENT PEAK PRESSURE ANALYSIS

Initial Conditions	
TS Containment Air Partial Pressure, psia	11.3
Initial Containment Pressure, psia [a]	13.52
Initial Air Temperature, F	125.5
Relative Humidity, %	100
Results	
Peak containment pressure, psia	59.48
Time of peak containment pressure, sec	215.7
Peak containment temperature, F	274.4
Time of peak containment temperature, sec	213.7

a. GOTHIC total pressure is TS air pressure + 0.25 psi uncertainty + 1.97 psia vapor pressure.

Table 5.4-15
ACCIDENT CHRONOLOGY MSLB PEAK PRESSURE ANALYSIS

Event	Time (sec)
Accident start	0.0
CLS High High containment pressure	4.2
Start SI	27.9
CS delivered to containment	101.2
Containment peak pressure	215.7
Faulted SG dryout	235.0
AFW terminated	1800
Transient Termination	7200

Table 5.4-16
MSLB CONTAINMENT PEAK TEMPERATURE ANALYSIS

Initial Conditions	
TS Containment Air Partial Pressure, psia	10.1
Initial Containment Pressure, psia [a]	9.85
Initial Air Temperature, F	125.5
Relative Humidity, %	0
Results	
Peak containment temperature, F	318.9
Time of peak containment temperature, sec	31.1
Peak containment pressure, psia	47.4
Time of peak containment pressure, sec	412.1

a. GOTHIC containment pressure = TS air pressure - 0.25 psi uncertainty (no vapor pressure).

Table 5.4-17
KEY PARAMETERS IN THE CONTAINMENT ANALYSIS

Parameter	Value
Maximum Core Power (100.38% × 2587 rated thermal power), MWt	2597
Containment Air Partial Pressure Uncertainty, psi	± 0.25
Containment Temperature, °F (includes 0.5°F uncertainty)	74.5–125.5
Containment Relative Humidity, %	0–100
SW Temperature, °F	24–101
RWST Temperature, °F (includes 1.6°F uncertainty) [a]	32–46.6
Accumulator Pressure, psia (includes uncertainty)	578-706
Accumulator Temperature, °F	75-105
Accumulator Water Volume, ft^3	975–1025
Accumulator Nitrogen Volume, ft^3 (includes uncertainty)	416-484
Minimum Service Water Flow Rate with 10% RSHX tube plugging, gpm	7789 at Accident Start [b]
Maximum Service Water Flow Rate with 0% RSHX tube plugging, gpm	10,000 [b]
ORS Pump Flow Rate, gpm	2900–3300
IRS Pump Flow Rate, gpm	3100–3650
LHSI Injection Mode Flow Rate (Single-Train), gpm	2844–3264
Maximum LHSI Recirculation Mode Flow Rate (Single-Train), gpm	3330
HHSI Injection Mode Flow Rate (Single-Train), gpm	435–528
Minimum CS Bleed Flow Rate to ORS Pump Suction, gpm	See Note c
Minimum IRS Recirculation Flow Rate to Pump Suction, gpm	300
CS Flow Rate, gpm	See Note d
IRS Piping Fill Volumes, ft^3	358–421.3
ORS Piping Fill Volumes, ft^3	456.5–558.1

a. Minimum RWST temperature of 32°F is assumed for evaluation of the inadvertent CS actuation event. Normal operating range for RWST temperature is 40–45°F.
b. SW minimum flow rate decreases as the intake canal level decreases during the accident. The initial value is specified for a canal level of 23 ft. For maximum flow, a constant 10,000 gpm is assumed throughout the accident (ORS pump NPSHa analyses are not very sensitive to this input).
c. For the RS pump NPSH analyses, the CS bleed flow is input as a function of differential pressure between the containment and the RWST (C-L in psid). The flow rate varies from 294 gpm (26.8 psid) to 325.6 gpm (-8.6 psid and maintained constant for more negative differential pressures).
d. The CS flow rate varies as a function of differential pressure between the containment and RWST (C-L in psig). The minimum single-pump flow rate varies from 2006 gpm (26.9 psid) to 2708 gpm (-4.0 psid and maintained constant for more negative differential pressures). The maximum single-pump flow rate varies from 2409 gpm (26.9 psid) to 3024 gpm (-10.0 psid and maintained constant for more negative differential pressures).

Table 5.4-17 (CONTINUED)
KEY PARAMETERS IN THE CONTAINMENT ANALYSIS

Parameter	Value
CS Spray Delivery Delay from CLS signal, sec	59–97
LHSI Pump Suction Friction Loss at maximum 1-pump flow, ft	6.8
ORS Pump Suction Friction Loss at maximum flow, ft	6.8
IRS Pump Suction Friction Loss at maximum flow, ft	2.0
CLS High High Containment Pressure, psia	27
RWST WR Level for RS Pump Start (60% ± 2.5% uncertainty)	57.5%–62.5%
ORS Pump Start Time Delay, seconds (±12 second timer uncertainty and 0 or 10 seconds for ramp to full flow depending on which is conservative)	108–142
RWST WR Level Setpoint for RMT (13.5% ± 2.5% uncertainty)	11.0–16.0%
Time to complete RMT function, minutes	2–3
Minimum RWST volume at accident initiation, gallons	384,000 (95% NR)
Minimum containment free volume, ft^3	1,730,000
Maximum containment free volume for NPSHa Analysis, ft^3	1,819,000

Figure 5.4-1
CONTAINMENT PRESSURE DEHLG PEAK PRESSURE ANALYSIS

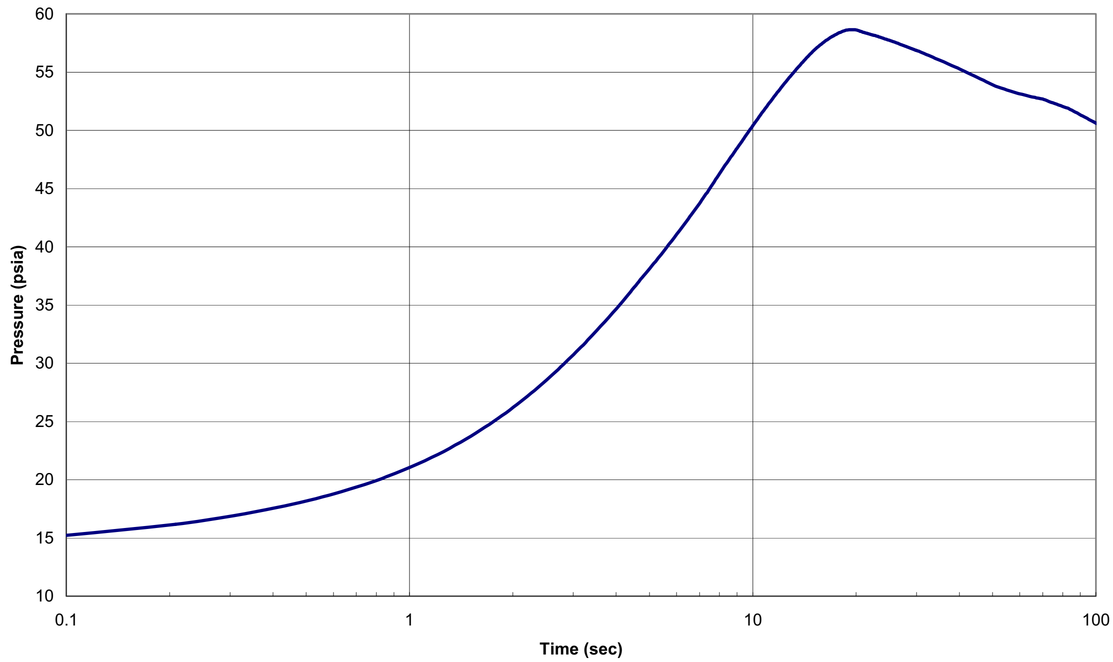


Figure 5.4-2
CONTAINMENT VAPOR TEMPERATURE DEHLG PEAK PRESSURE ANALYSIS

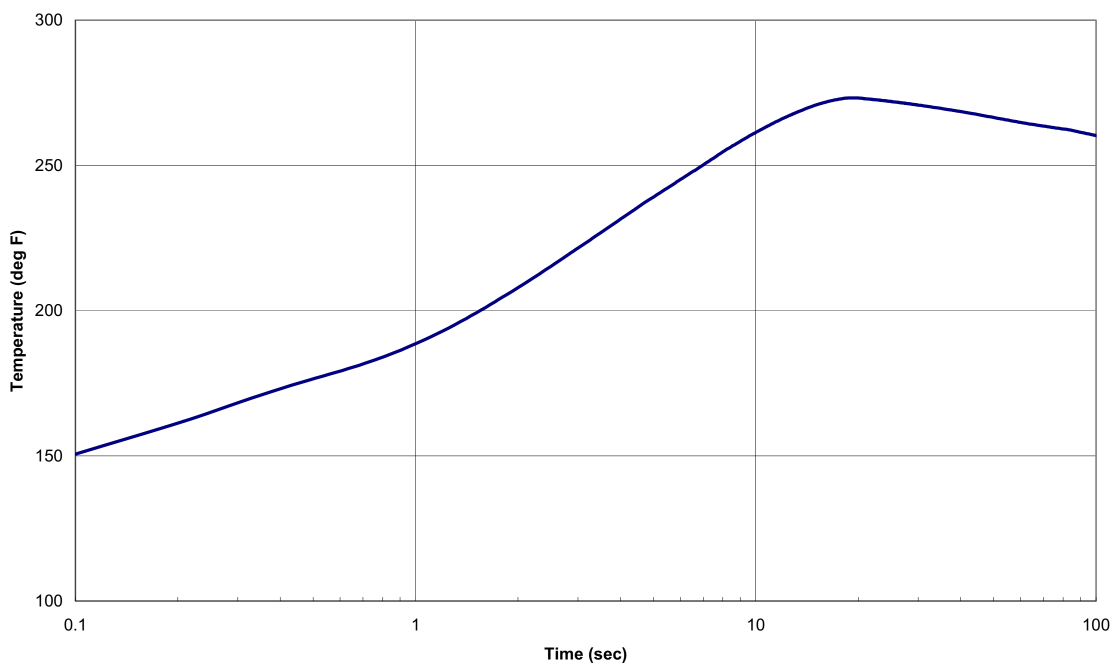


Figure 5.4-3
CONTAINMENT PRESSURE DEPSG DEPRESSURIZATION ANALYSIS

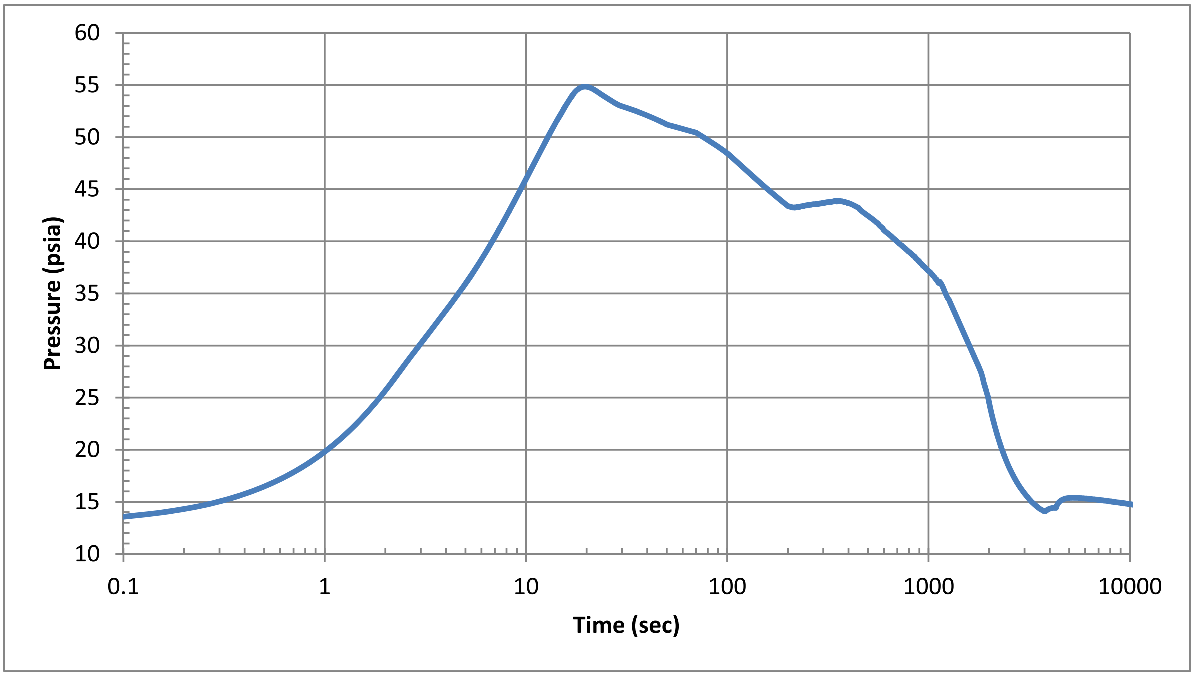


Figure 5.4-4
CONTAINMENT TEMPERATURES DEPSG DEPRESSURIZATION ANALYSIS

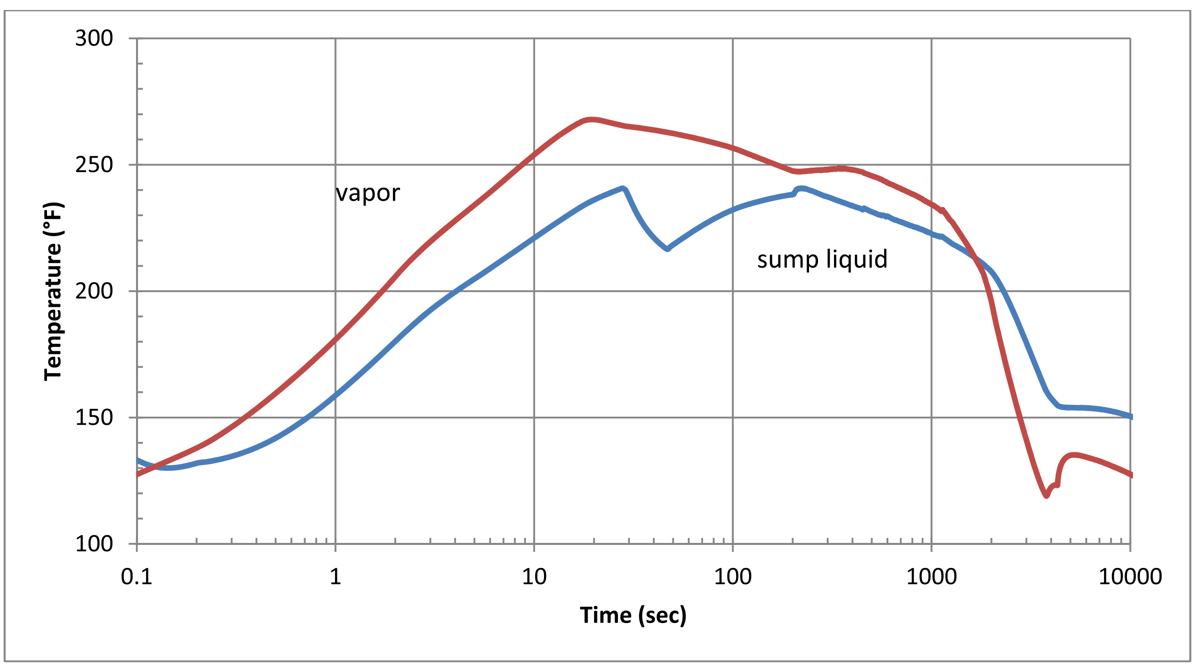


Figure 5.4-5
TOTAL RS HEAT EXCHANGER HEAT RATE DEPSG DEPRESSURIZATION ANALYSIS

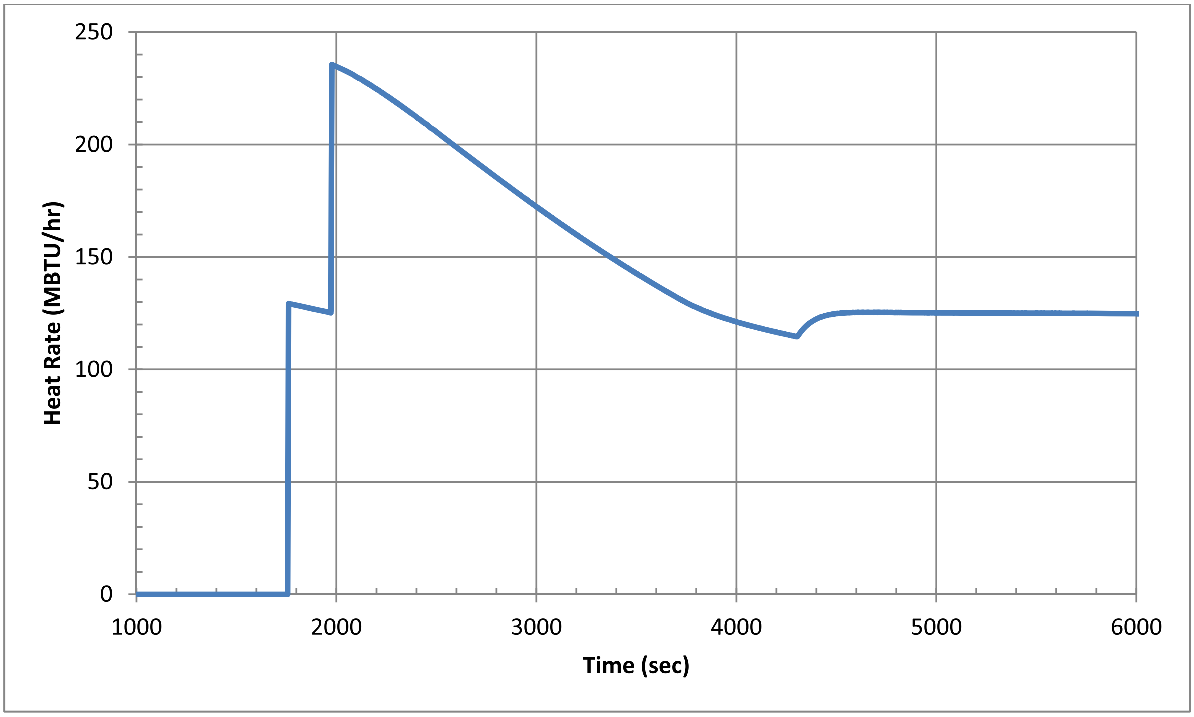


Figure 5.4-6
CONTAINMENT PRESSURE 1.4 FT^2 MSLB PEAK PRESSURE ANALYSIS

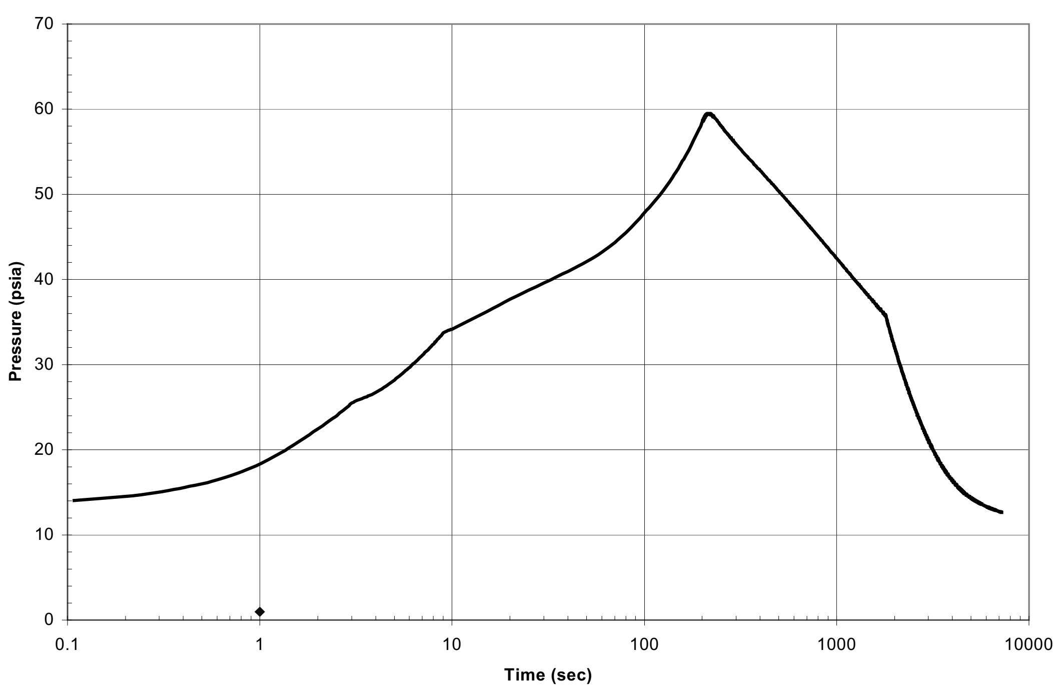


Figure 5.4-7
CONTAINMENT TEMPERATURE 1.4 FT^2 MSLB PEAK PRESSURE ANALYSIS

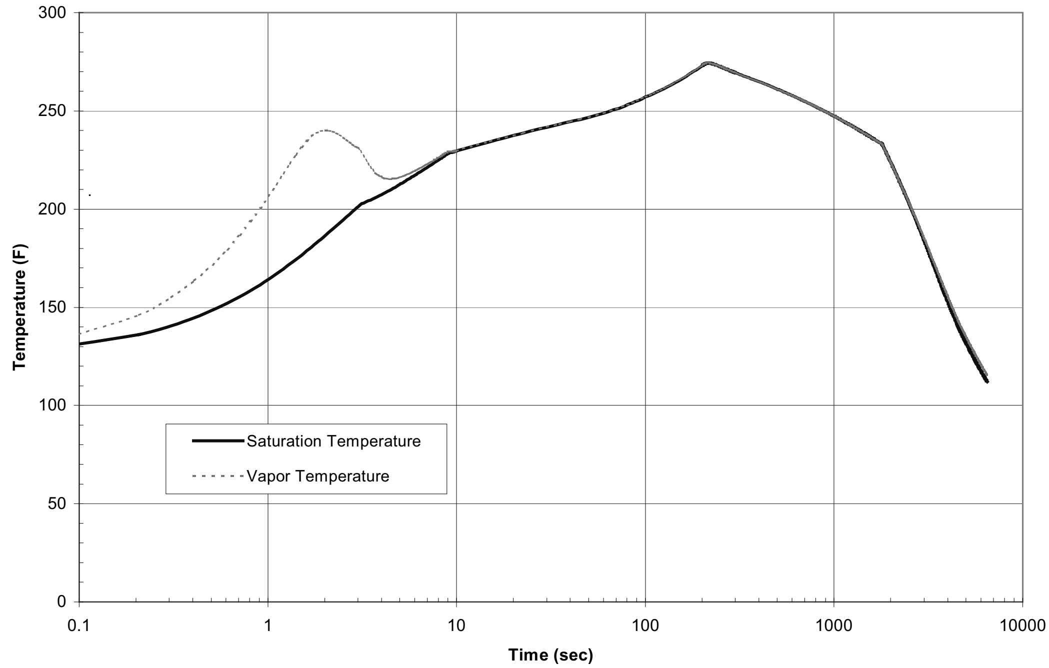


Figure 5.4-8
CONTAINMENT PRESSURE 0.6 FT^2 MSLB PEAK TEMPERATURE ANALYSIS

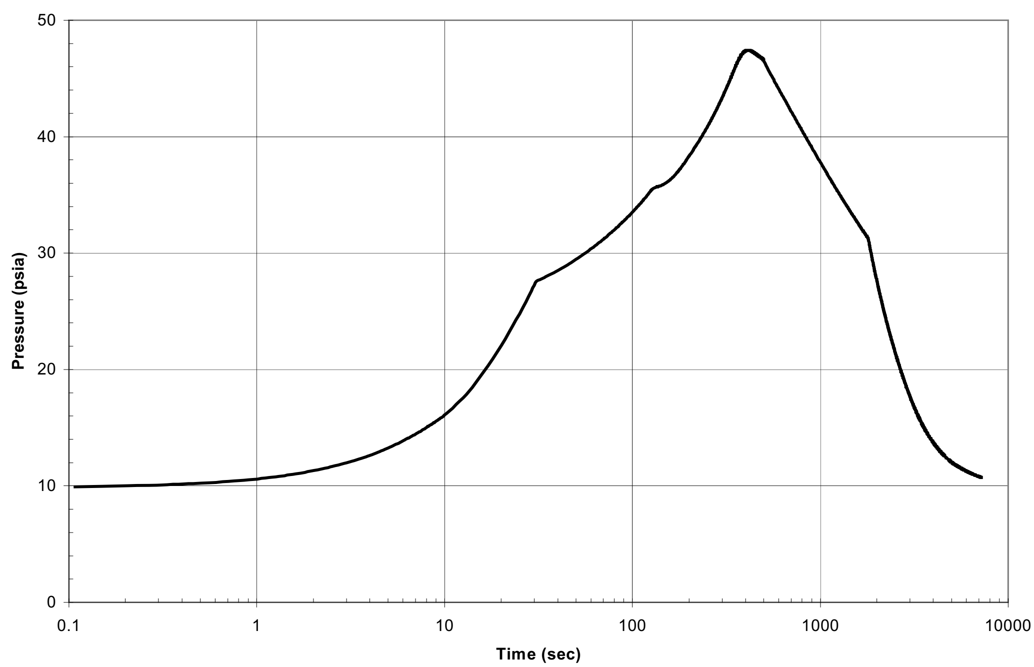
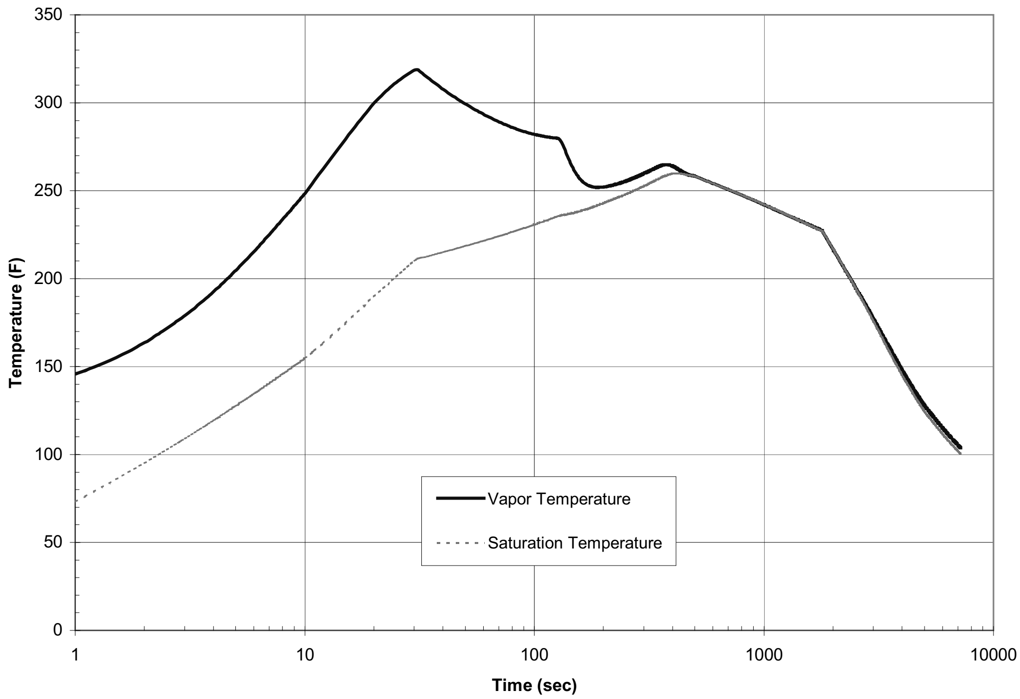


Figure 5.4-9
CONTAINMENT TEMPERATURE 0.6 FT^2 MSLB PEAK TEMPERATURE ANALYSIS



5.5 CONTAINMENT TESTS AND INSPECTIONS

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

5.5.1 Initial Containment Testing

A testing and surveillance program was in effect during construction and continues in effect during operation (See 5.5.3) to confirm that the containment can perform its intended function. The initial program consisted of construction testing, and an initial leakage rate test. Materials and fabrication inspections and tests are described in Section 15.4.

Construction testing included provisions for testing the leaktightness of all penetrations and liner welds during construction and for an air pressure test when the containment was completed to ensure the structural integrity of the containment. Electrical penetrations were assembled and tested as a unit for leaktightness following installation in the containment (Section 15.5).

Leaktightness testing of all liner welds during construction was performed by welding a structural steel gas test channel over each weld seam. For the bottom and the straight shell, the test channels were placed on the inside of the liner. For the dome, the test channels were on the outside (concrete side) of the liner.

These channels formed a space into which pure Freon at 50 psig was injected. The weld seams were then tested for leakage using a halogen leak detector. The test channels did not form a single continuous channel but were segmented for convenience in testing. Test gas was introduced through threaded connections after evacuating the channels to ensure a homogeneous test gas throughout the channel section. If a leak rate of greater than 1.8×10^{-5} cm^3/sec was found, the defective test channel seam or liner weld seam was ground out and the weld remade and retested. After testing, the gas was purged from the channels with air and the threaded connections plugged.

The air pressure test to ensure the structural integrity of the containment was performed after the liner was completed, the last concrete pour cured, and all penetration sleeves installed. The containment pressure was raised to 52 psig (115.5% of the 45 psig design pressure) and held for 1 hour, thus ensuring the structural integrity of the containment.

The initial leakage rate tests were performed at 39.2 psig and 25 psig, after the completion of construction and the installation of all systems penetrating the containment boundary. On Unit 1, an additional leakage rate test was performed at 9 psia. These testes were performed using the reference volume method as described under the leakage-monitoring system (Section 5.3.2).

5.5.2 Continuing Containment Leakage Testing

A testing program is in place to measure primary containment leakage periodically throughout the plant's operating life. The testing program includes performance of Type A tests to measure the overall integrated leakage rate, Type B tests to detect and measure local leakage across pressure-containing or leakage-limiting boundaries other than valves, and Type C tests to measure containment isolation valve leakage rates.

The leakage tests are performed in accordance with the requirements of 10 CFR 50 Appendix J, *Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors.*

5.5.3 Containment Integrated Leakage Rate Test (Type A)

A Type A test program has been developed and is scheduled and conducted in accordance with 10 CFR 50 Appendix J, Option B and NEI 94-01, Revision 3-A, *Industry Guidelines for Implementing Performance-Based Option of 10 CFR 50, Appendix J, Option B*. Each Type A test establishes the measured containment leakage rate, L_{am}, which verifies that the maximum allowable leakage rate, L_a, used in the accident analysis is not exceeded.

Type A tests are conducted at periodic intervals based on historical performance of the overall containment system in accordance with 10 CFR 50, Appendix J, Option B, and NEI 94-01, Revision 3-A. The leakage rate must not exceed the allowable leakage rate (L_a) with margin as specified in the Technical Specifications.

A general inspection of the accessible interior and exterior surfaces of the containment is performed, prior to each Type A test and at periodic intervals between tests based on performance, to detect structural deterioration. Defects are resolved prior to conducting the test.

Test instrumentation includes an absolute manometer, temperature detectors, and dewpoint sensors.

The containment isolation valves are closed by their normal mode of operation. Where possible, lines subjected to containment atmosphere following a LOCA are drained and vented during the Type A test. Systems that are normally filled with water and operating under post-accident conditions are not drained and vented nor are their Type C test results included in the Type A test leakage rate. For those systems that should be vented and drained but are not, the Type C test result is added to the Type A leakage rate.

After completion of the procedural prerequisites, the containment is pressurized to slightly greater than containment design pressure (45 psig) and allowed to stabilize for a minimum of 4 hours. The Type A test period normally commences when the rate of change of the containment air temperature for the latest hour does not deviate by more than 0.5°F/hr from the average rate of change over the last 2 hours. A test computer is normally used for data acquisition and/or leakage rate calculations. The data acquisition package reads the inputs (pressure, temperature, and dewpoint temperature), converts these readings into engineering units, and stores/prints these values to be used for leakage rate calculations. The leakage rate is calculated using the absolute method of mass point analysis. The absolute method of mass point analysis consists of periodically calculating air masses within the containment structure over a period of time from pressure, temperatures, and dew point observations during the test. The air masses are computed using the ideal gas law. The leakage rate is then determined by plotting the air mass as a function of time, using a least-squares fit to determine the slope. The leak rate is expressed as a percentage of containment air mass lost in 24 hours. A 95% confidence level is calculated using a T distribution. The sum of the leakage rate at a 95% confidence level must be less than 0.75 L_a.

A verification test is performed following each Type A test. This test provides a method of assuring that systematic error or bias is given adequate consideration. The verification test consists of a superimposed leakage rate equal to 75% to 125% of L_a, which is measured independently from Type A test instrumentation. This air change and that which is measured by the containment leakage Type A instrumentation must agree within ±25% L_a.

5.5.4 Containment Penetration Leakage Rate Test (Type B)

Type B tests measure local leakage across containment pressure boundaries that are either atypically large and/or whose design incorporates resilient seals, gaskets, or sealant compounds, and piping penetrations fitted with expansion bellows.

Type B tests, except airlocks, are performed at periodic intervals based on the historical performance at each penetration in accordance with 10 CFR 50, Appendix J, Option B, and NEI 94-01, Revision 3-A, *Industry Guidelines for Implementing Performance-Based Option of 10 CFR 50, Appendix J, Option B*. Air locks are tested at the frequency described in Section 5.5.6. Type B tests are performed by either one of two methods.

The first method is to pressurize between the double o-ring seals of the cover used as the containment pressure barrier (i.e. air lock doors, electrical penetration flanges, fuel transfer blank flange). The makeup air method is used to determine the penetration leakage by applying a test pressure equal to or greater than containment design pressure (45 psig) between the o-ring seals.

The second method also uses the makeup air method when performing the full blown air lock test. The space between the inner and outer air lock door is pressurized to a test pressure equal to or greater than containment design pressure (45 psig).

The acceptance criterion for the combined leakage rate of the penetrations and valves subject to Types B and C tests shall be equal to or less than 60% of the maximum allowable leakage rate of the containment.

5.5.5 Containment Isolation Valve Leakage Rate Test (Type C)

There are two methods used in Type C tests. With either method, each valve to be tested is closed by normal operation without any preliminary exercise or adjustment.

In Method 1, the section of piping with the containment isolation valves is isolated from the remainder of the fluid system by using valves or blank flanges as necessary, and the piping is drained. The inside and outside containment isolation valves are tested individually with air at a pressure equal to or greater than containment design pressure. Test air is applied at a test connection on the inboard side (toward the inside of the containment structure) of the valve to be tested, and the leakage air is vented through a test vent on the outboard side of the valve. A flowmeter, connected in line with the pressure source, is used to measure leakage through the containment isolation valve as a function of time. In this procedure, the test airflow is directed across the valve seat from the inside-to-the-outside containment structure direction.

In Method 2, the section of piping with the containment isolation valves is isolated from the remainder of the fluid system, using valves or blank flanges as necessary, and the piping is drained. The inside and outside containment isolation valves are tested simultaneously with air at a pressure equal to or greater than containment design pressure. Test air is applied at a test connection between the two valves, and leakage air is vented through a test vent on the outboard side of the penetration. A flowmeter connected in line with pressure source is used to measure leakage through the containment isolation valves as a function of time. The containment isolation valves are typically diaphragm or symmetric butterfly type valves. The outside containment isolation valves are tested in the outward direction. The inside containment isolation valves are tested in the reverse direction. This test is equally effective for diaphragm and symmetric butterfly valves. Penetrations 90, 91, and 103 are tested using this method.

The acceptance criterion for the combined leakage rate of the penetrations and valves subject to Type B and C tests shall be equal to or less than 60% of the maximum allowable leakage rate of the containment.

Tables 5.2-1 and 5.2-2, for Units 1 and 2 respectively, identify those valves that are required to be tested in accordance with 10 CFR 50 Appendix J, Option B to ensure containment integrity during LOCA conditions. The basis for valves which are: (1) not Type C tested; (2) Type C tested but the leakage penalty is not included in the overall Type B and C total leakage; or (3) Type C tested but the leakage penalty is not included in the overall Type A leakage is provided below:

Main Steam and Feedwater Penetrations	Reason for Type C Testing Exemption
39, 40, 41, 73, 74, 75, 76, 77, 78, 87, 88, 102	These penetrations are directly connected to the steam generator secondary side and, therefore, are considered a closed system (an extension of the primary containment). In addition, the S/G remains at a pressure greater than Pa for at least the first hour and is not considered a credible leakage path from containment. Reference: T.S. Amendment 72/73 dated September 29, 1981

Component Cooling Penetrations	Reason for Type B & C Leakage Exclusion
1, 2, 4, 5, 9, 10, 11, 12, 13, 14, 16, 17, 18, 25, 26, 27, 110	These penetrations are a closed system. Containment penetration check valves and trip valves are leakage tested, but the leakage is not included in the 10 CFR 50 Appendix J Type B and C total leakage. During the associated check valve leakage test, the containment penetration manual isolation valve is leak tested in the reverse direction. The valve is tested with system pressure on the upstream side and the downstream side vented. Reference: T. S. Amendment 72/73 dated September 29, 1981

Safety Injection Penetrations	Type C Tested but Leakage Penalty not Included in Overall Type A Leakage
7, 15, 21, 23, 46, 60, 61, 62, 66, 67, 68, 69, 113	These penetrations are water filled and/or normally operating under accident conditions at a pressure greater than P_a. Therefore, these penetrations are not considered credible leakage paths from containment. Reference: NRC SER dated November 21, 1988.

RCP Seal Water Penetrations	Not Type C Tested
35, 36, 37	Needle valves are throttled open and administratively controlled. These lines remain open after a safety injection signal and contribute to the total injection flow while cooling the RCP seals. The three incoming lines have a check valve inside containment and a local manual valve (throttle valve) outside containment, combined with both a closed system and a continuous water seal at a pressure sufficient to preclude containment atmospheric leakage.

Service Water to RSHX Penetration	Reason for Type B & C Leakage Exclusion
79, 80, 81, 82, 83, 84, 85, 86	These systems are closed systems. Each train is leak tested but the leakage is not included in the 10 CFR 50 Appendix J Type B and C total leakage. The valves in these lines remain open during a design basis accident. Reference: T. S. Amendment 72/73 dated September 29, 1981.

5.5.6 Scheduling and Recordkeeping of Periodic Tests

Primary containment integrated leakage rate tests are conducted at periodic intervals based on historical performance of the overall containment system. Type A tests are only conducted while the plant is in the shutdown condition.

If any periodic Type A test fails to meet the acceptance criteria, the schedule for subsequent Type A test is determined in accordance with 10 CFR 50, Appendix J, Option B, and NEI 94-01, Revision 3-A, *Implementation Guidelines for Implementing Performance-Based Option of 10 CFR 50, Appendix J.*

Containment resilient seal penetration tests (Type B tests) were performed prior to initial criticality and are performed periodically thereafter during shutdown for refuelings, in accordance with 10 CFR 50 Appendix J, Option B, and NEI 94-01, Revision 3-A.

The personnel air lock full volume test was performed prior to initial fuel load and is performed periodically thereafter, in accordance with 10 CFR 50 Appendix J, Option B and NEI 94-01. If the air lock is open during periods when containment integrity is not required, the lock is tested only at the end of those periods. If the air lock is opened when containment integrity is required, the air lock is tested within 7 days after such opening. If the air lock door is opened more frequently then once every 7 days, the air lock seals are tested at least once every 30 days during the period of frequent opening. The personnel air lock and personnel escape hatch have testable seals and testing of the seals fulfills the 10 CFR 50 Appendix J after each use requirement. Seal tests are not substituted for the air lock full volume test.

Containment isolation valve testing (Type C tests) was performed prior to initial criticality and is performed periodically thereafter during each reactor shutdown for refueling, in accordance with 10 CFR 50 Appendix J, Option B.

The results of periodic Type A, B, and C tests are documented to show that performance criteria have been met. The comparison to previous results of the performance of the overall containment and of individual components are documented to provide a basis for the established test intervals for the containment and individual components.

5.5.7 Special Testing Requirements

Type A, B, and C tests, as applicable, are conducted following containment structure modifications in accordance with 10 CFR 50 Appendix J, Option B, and NEI 94-01, Revision 3-A, *Implementation Guidelines for Implementing Performance-Based Option of 10 CFR 50, Appendix J.*

Surry Power Station
Updated Final Safety Analysis Report

Chapter 6

Intentionally Blank

Chapter 6: Engineered Safeguards
Table of Contents

Chapter 6: Engineered Safeguards
Table of Contents (continued)

Chapter 6: Engineered Safeguards

List of Tables

Chapter 6: Engineered Safeguards

List of Figures

CHAPTER 6 ENGINEERED SAFEGUARDS

6.1 GENERAL DESCRIPTION

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

The engineered safeguards, together with the containment (Chapter 5), protect the public and the station in the event of the design-basis accident, as defined in Sections 14.5.1.2 and 14.5.5. The engineered safeguards are designed to minimize the accident by performing the following three functions:

1. Supply borated water to the reactor coolant system to cool the core, decrease reactivity, limit fuel rod cladding temperatures, limit the metal-water reaction, and ensure that the core remains intact.
2. Limit the driving potential, including differential pressure and time duration, for leakage out of the containment structure.
3. Reduce the concentration of airborne fission products available for leakage.

The first function is satisfied by the timely, continuous, and adequate supply of borated water to the reactor coolant system and the reactor core. The second function is satisfied by the provision of heat sinks for the condensation of steam released inside the containment, the inherent depressurization of the containment below atmospheric pressure following the design-basis accident, and means for maintaining the containment at subatmospheric conditions for an extended period of time. The third function is satisfied by providing chemical additives (NaTB) to the sump water which is recirculated by the ECCS and recirculation spray systems to enhance the spray removal of radioactive iodine from the containment atmosphere.

The engineered safeguards systems provided for satisfying these functions are as follows:

1. A safety injection system (Section 6.2) that injects borated water into the cold legs of all three reactor coolant loops.
2. Two separate low-head safety injection subsystems, either of which provides long-term removal of decay heat from the reactor core.
3. Two separate subsystems of the spray system (containment spray and recirculation spray) that operate together to reduce the containment temperature, return the containment pressure to subatmospheric, and remove heat from the containment. The recirculation spray subsystem maintains the containment subatmospheric and transfers heat from the containment to the service water system (Section 9.9).

A composite schematic diagram of the engineered safeguards systems is shown in Figures 6.1-1 and 6.1-2 for Units 1 and 2, respectively.

The safety injection system provides for the charging of borated water to the reactor coolant system from the accumulators following a LOCA. The three accumulators are self-contained and are designed to supply water as soon as the reactor coolant system pressure drops below 600 psig. Additional makeup to the reactor coolant system is provided by the charging pumps, operating in the safety injection mode, and the low-head safety injection pumps. Both the charging and low-head safety injection pumps are located outside the containment, are driven by an electric motor, are capable of being rapidly energized or operated, and are powered from the emergency power buses. The pumps also ensure an adequate supply of borated water for an extended period of time by recirculating water from the containment sump to the reactor core through two separate flow paths.

The containment spray subsystem supplies chilled borated water to the containment immediately following the receipt of the safeguards initiation signal. This subsystem includes two full-capacity, electric-motor-driven containment spray pumps that are located outside the containment and are supplied with power from the emergency buses. The containment spray pumps supply chilled water from the refueling water storage tank to the containment. Either pump is capable of furnishing sufficient spray water to prevent overpressurizing the containment structure.

The recirculation spray subsystem recirculates water from the containment sumps through service-water-cooled recirculation spray heat exchangers to the recirculation spray headers. Two of the four 50% design capacity, motor-driven recirculation spray pumps are located outside the containment. All four of the recirculation spray coolers are located inside the containment and transfer containment heat to the service water system (Section 9.9). Sodium Tetraborate Decahydrate (NaTB) is stored in baskets inside containment to increase the alkalinity of the sump water produced during an event which exceeds the CLS high-high containment pressure actuation setpoint. The NaTB solution is recirculated by the recirculation spray subsystem to ensure effective removal of radioactive iodine.

The containment spray and recirculation spray subsystems are capable of reducing the containment pressure to subatmospheric in less than 60 minutes, thus terminating all outleakage to the environment. This original design criterion was modified in conjunction with the analyses for implementation of the alternative source term. The criteria were subsequently updated to support an increase in the containment depressurization profile for the alternative source term analyses. The updated criteria require that, following the LOCA, the containment pressure be less than 2.0 psig within 1 hour and less than 0.0 psig within 6 hours. The radiological consequences analysis demonstrates acceptable results provided the containment pressure does not exceed 2.0 psig for the interval from 1 to 6 hours following the Design Basis Accident. Beyond 6 hours, containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

The containment vacuum system removes any subsequent air inleakage after the containment pressure has been reduced to subatmospheric. Because of the inherent low-leakage design of the containment, the use of the vacuum pumps will probably not be required for several months after a major LOCA or the design-basis accident. Either of the two vacuum pumps is capable of removing sufficient air to maintain the containment subatmospheric indefinitely following any LOCA or design-basis accident, as discussed in Chapter 14.

The electrical components of all engineered safeguards may be operated on ac power provided from two independent emergency buses. Should all outside power sources fail, highly reliable onsite power is ensured by emergency generators, as described in Section 8.5. If one emergency generator should fail, the electrically driven engineered safeguards equipment may be transferred by manual control to the other emergency generator. Engineered safeguards can be manually operated from the control room. For the purpose of definition, the minimum engineered safeguards equipment started under emergency power conditions is as follows:

1. One charging pump (100% capacity).
2. One low-head safety injection pump (100% capacity).
3. Two recirculation spray pumps (100% total capacity).
4. One containment spray pump (100% capacity).

An evaluation of these systems under various conditions is presented in Chapter 14.

Periodic testing of the engineered safeguards components is performed as discussed under the individual systems later in this chapter. Components of the engineered safeguards system have been located in accessible areas, and visual inspection is performed periodically to ensure that the system is operable.

Safety-related equipment located in the containment that will be operable during and subsequent to a LOCA or steam-line break accident is as follows:

1. The inside recirculation spray pumps.
2. The inside recirculation spray pump motors.
3. The associated electrical cables for the recirculation spray pump motors.

Figure 6.1-1
UNIT 1 ENGINEERED SAFEGUARDS SYSTEMS

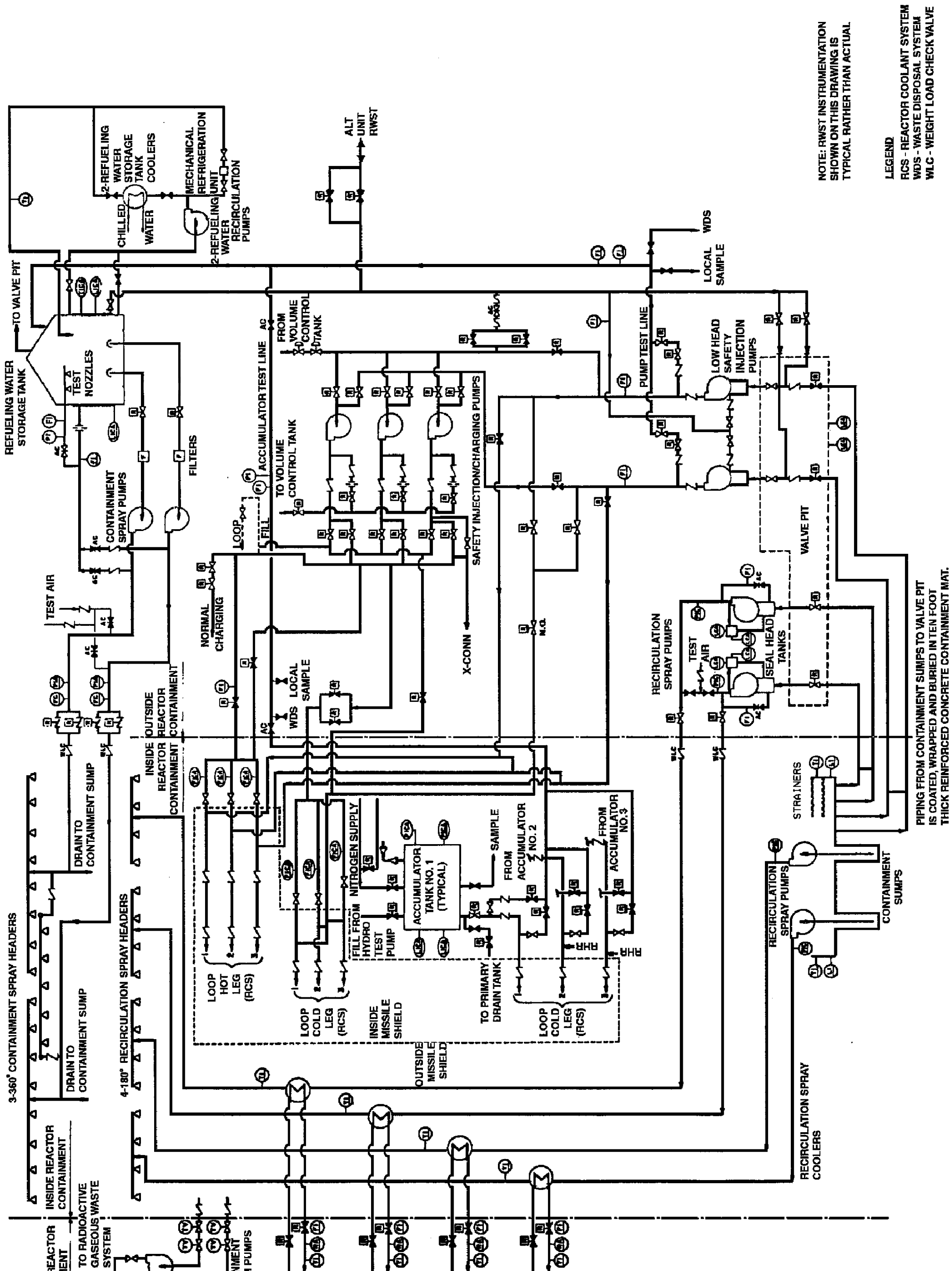
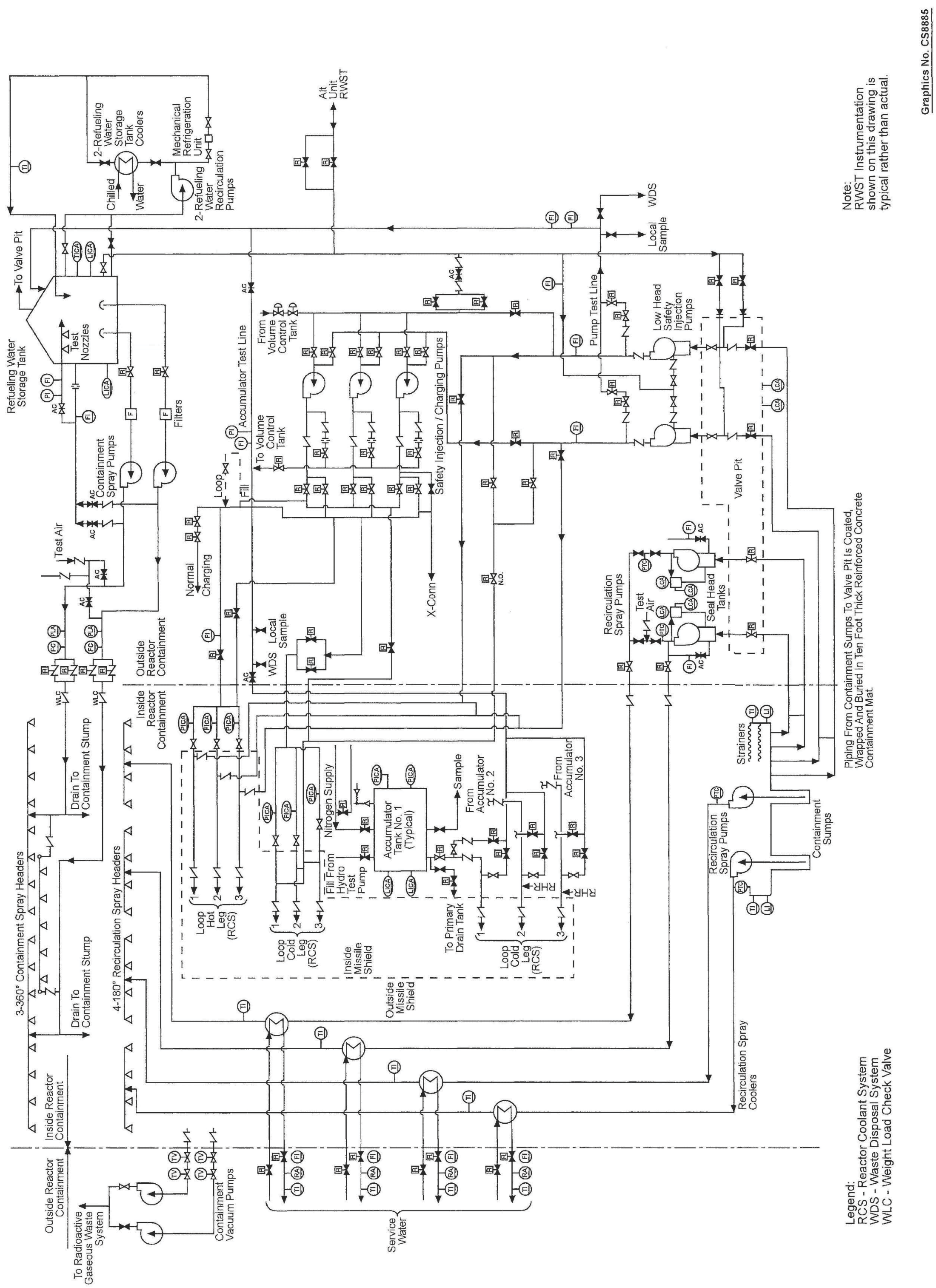


Figure 6.1-2
UNIT 2 ENGINEERED SAFEGUARDS SYSTEMS



Intentionally Blank

6.2 SAFETY INJECTION SYSTEM

6.2.1 Design Bases

6.2.1.1 Performance Objectives

The design bases for the safety injection system are:

1. To protect the unit and the public by maintaining clad integrity and thus minimizing the release of fission products from the fuel during the unlikely event of a LOCA.
2. To protect the core for a range of possible mishaps (evaluated as more likely than a LOCA), thereby minimizing financial loss and loss of power generation capability.

The specific technical objectives of the safety injection system are:

1. For the assumed LOCA (double-ended rupture of a reactor coolant pipe), or the LOCA associated with a control rod assembly ejection, or the rupture of a steam generator tube.
   a. To automatically deliver borated cooling water to the reactor core in large enough volume and soon enough after the accident so that:
      1) The cladding temperature is less than its melting temperature, and is less than the temperature at which gross core geometry distortion or clad fragmentation may be expected.
      2) The total core metal-water reaction is limited to less than 1%.
   b. To shut the reactor down and maintain it at 1% shutdown with all but one control rod assembly inserted (after long-term core operation at rated core power of 2587 MWt).

      These criteria ensure that the core remains in place and substantially intact to such an extent that effective cooling of the core is not impaired.
2. For the steam-line break or uncontrolled cooldown:
   a. To maintain the core in place and essentially intact so as not to impair effective cooling of the core, with the most reactive control rod assembly withdrawn, no offsite power, and a single failure in the engineered safeguards systems.
   b. To limit clad damage to an insignificant amount for the worst steam-line break, with no stuck control rod assembly, with offsite power available, and with all engineered safeguards.
   c. To prevent DNB after shutdown and during cooldown due to any single active failure, for example, the opening of a steam-line relief valve.

The safety injection system meets the intent of General Design Criteria 37 through 48, as discussed in Section 1.4, because:

1. The safety injection system objectives are met even though a loss of normal station power has occurred coincident with the accident.
2. Any single active failure during injection does not prevent the accomplishment of safety injection system objectives. One active or passive failure in the systems required for long-term safety injection system operation does not prevent the accomplishment of safety injection system objectives, nor cause the total offsite dose to exceed the limits of 10 CFR 50.67 or RG 1.183 guidelines, as appropriate, assuming credit is taken for detection and operator action.
3. Critical parts of the safety injection system and of the reactor coolant system are periodically inspected.
4. Active components of the safety injection system are tested periodically to ensure that each component is operable.
5. An integrated safety injection system test of active components is performed periodically during shutdown without introducing flow into the reactor coolant system.
6. Maintenance outages of active components are permitted only for limited periods of time.
7. It is assumed that the highest worth control rod assembly remains stuck out of the core on reactor trip.
8. Components exposed to the accident environment are designed to operate in that environment for the length of time required.

6.2.1.2 **Codes and Classifications**

Table 6.2-1 lists the codes and standards to which the safety injection system components are designed.

6.2.2 System Design and Operation

6.2.2.1 **System Description**

Adequate emergency core cooling following a LOCA is provided by the safety injection system shown in Figure 6.2-1 and Reference Drawings 1 & 2. The system components operate in the following possible modes:

1. Injection of borated water by the passive accumulators.
2. Injection of borated water initially from the refueling water storage tank with the safety injection charging pumps, and injection by the low-head safety injection pumps drawing borated water from the refueling water storage tank.
3. Recirculation of spilled coolant and injection water back to the reactor from the containment sump using the low-head safety injection pumps and by the safety injection charging pumps, if required by the situation.

The initiation signal for core cooling by the safety injection charging pumps and the low-head safety injection pumps is the safety injection signal that is actuated by any of the following:

1. Low-low pressurizer pressure.
2. High containment pressure (three-out-of-four).
3. Steam-line differential pressure (two-out-of-three between each steam line and main steam header).
4. High steam flow in any two of three steam lines (one-out-of-two per line) coincident with low steam-line pressure (two-out-of-three in steam generator header), or low T_{avg}.
5. Manual actuation.

6.2.2.1.1 Injection Phase

The principal components of the safety injection system that provide emergency core cooling immediately following a loss of coolant are the three accumulators (one for each loop), three safety injection charging pumps (which perform the charging functions during normal operation), and the two low-head safety injection pumps. The safety injection charging pumps are located in the auxiliary building. The low-head safety injection pumps are located in the safeguards area alongside the containment building with the pump impeller actually located within an extension of the containment boundary.

The accumulators, which are passive components, discharge into the cold legs of the reactor coolant piping when reactor coolant system pressure decreases below accumulator pressure, thus ensuring rapid core cooling for large breaks. They are located inside the containment, and are protected against possible missiles.

The safety injection signal opens the safety injection system isolation valves and starts the safety injection pumps. The accumulator isolation valves also receive the safety injection signal.

Following a safety injection signal, the maximum velocity of water is 125 fps in the accumulator discharge lines and approximately 40 fps in the high-head safety injection system lines (assuming two pumps deliver through 3-inch common cold leg injection lines).

When the reactor coolant system pressure falls below the accumulator pressure, the check valve opens and borated water is forced into the coolant system. The resultant hydraulic forces are controlled by snubbers located at various points on the piping system. Snubbers on the accumulator discharges lines do not eliminate the potential for water hammer; however, water hammer is not expected, since the relative low pressure of the low-head safety injection pumps would not rapidly close the check valves.

The snubbers are of the hydraulic type, which permits cyclic thermal movement. During slow cyclic excursions, the snubber exerts no restraint on the piping system. Rapid movement of the piston (caused by the hydraulic force) will cause a pressure differential between the ends of the snubber valve piston. This differential is sufficient to close the bypass ports in the valve, making the piston immovable and providing the resistive force. Snubbers are designed for tension or compression.

The valves of the high-head safety injection system open or close in approximately 10 seconds (in contrast to accumulator check valves, which open almost instantaneously), and therefore the hydraulic force should present no problem. The relatively slow closure time of these valves should present no water-hammer problems.

The safety injection charging pumps deliver borated water to the cold legs of the reactor coolant loops via separate discharge headers. These pumps provide for the makeup of coolant and add negative reactivity following a small break that does not immediately depressurize the reactor coolant system to the accumulator discharge pressure. For large breaks, they start delivery after the accumulators start their discharge.

The suction of the safety injection charging pumps is diverted from the normal suction at the volume control tank to the refueling water storage tank by the safety injection signal. (See Section 6.2.2.1.4.) The pumps feed two injection headers. The normal injection header contains redundant parallel isolation valves which open on receipt of a safety injection signal.

For large breaks, the reactor coolant system is depressurized and emptied of coolant rapidly (about 10 seconds for the largest break) and a high flow rate is required to quickly recover the exposed fuel rods and limit possible core damage. To achieve this objective, three accumulators are provided. Two low head safety injection pumps each delivering to a separate header are available to provide for an active component failure. Delivery from one low-head pump is required to supplement the accumulator discharge.

For large-area ruptures, the flow from the low-head portion of the system completes and maintains the core reflooding started by the accumulators. The accumulator injection starts core reflooding, as well as the termination of the clad temperature rise. The pumping systems ensure that the core is reflooded and that the reactor vessel is flooded at least to the nozzle. The core decay heat is removed by boiloff of the injected water, and ultimately the core is subcooled. The low-head pumps will recirculate the sump water, either directly to the reactor coolant loops for large breaks, or to the suction of the high-head pumps for small breaks, to ensure continued long-term cooling of the core.

Hot-leg connections for the low-head systems were selected to provide the optimum performance for the above functions and achieve a diversity of injection locations and flexibility to meet all long-term cooling requirements.

The cold-leg break is the most limiting, since the flow from one of the three accumulators is lost through the break, the steam-binding problem is more severe, and the clad temperatures at the end of blowdown are higher than for a comparable hot-leg break. The combination of these factors requires a larger flow for the cold-leg break. Evaluation of the high-head safety injection system show that the two unbroken cold-leg lines will deliver the required flow from one high-head pump, with allowance for part of the flow to spill through the break in the cold leg.

The low-head pumps provide the means to recirculate the sump water cooled by the spray heat exchangers and continue cooling the core through several alternate flow paths. The flow provided is in excess of that required to replace boiloff with allowance for spilling injection flow where applicable. If the loss of coolant occurred on the cold leg of one of the loops, the injected water would pass through the core to the break and ultimately subcool the core in the forced-circulation mode.

Motor-operated valves of the safety injection system that are normally energized during power operation and are under manual control, that is, valves that normally are in their ready position and do not receive a safety injection signal, have their positions indicated by position indicating lights on the control board. At any time during operation, if one of these valves is not in the ready position for injection, it is shown visually on the board. Motor operated valves of the safety injection system that are normally de-energized during power operation are verified to be in the ready position prior to removing power from the motor operator.

A detailed listing of the instrumentation readouts on the control board that the operator can monitor during initial injection is given in Table 6.2-2.

6.2.2.1.2 Changeover From Injection to Recirculation

The transfer of the safety injection suction lineup from the refueling water storage tank to the containment sump takes place automatically. The automatic transfer is initiated by a 2/4 matrix involving a refueling water storage tank level coincident with the two position key switches (one key switch for each train) being in the recirculation mode transfer position.

During the RMT sequence the following valves receive signals to reposition:

(Note: Preface each MOV number with a 1 or 2 depending upon the unit, i.e., 1-SI-MOV-1885A for Unit 1 and 2-SI-MOV-2885A for Unit 2.)

MOV-115B, D	HHSI pump suction isolation valves from the RWST
MOV-860A, B	LHSI pump suction isolation valves from the containment sump
MOV-862A, B	LHSI pump suction isolation valves from the RWST
MOV-863A, B	HHSI pump suction isolation valves from the LHSI pump discharge
MOV-885A, B, C, D	LHSI pump minimum flow recirculation isolation valves to the RWST

The valve alignment sequence begins with MOV-863A, B starting to open and MOV-885A, B, C, D starting to close when the RWST level setpoint for RMT switchover is reached. The maximum allowable operating time for these valves is one minute.

One minute after the RMT signal is generated, MOV-860A, B start to open and MOV-115B, D start to close. Once MOV-860A, B are fully opened, MOV-862A, B start to close. The maximum allowable time for this alignment is two minutes. Check valves are provided in the lines connecting the containment sump and the RWST to the LHSI pump suction to prevent cross connecting the sump with the RWST during the transfer sequence.

As described above, the entire sequence of automatic transfer (RMT) occurs within a minimum of two minutes and a maximum of three minutes. These maximum and minimum time intervals are used as inputs to the accident analyses.

The transfer system incorporates several functions to allow manual initiation of the switchover, automatic switchover as described above, bypass of system functions during refueling operations, and switchover by the existing method of individual valve alignment.

The level signals from the refueling water storage tank to the switchover circuitry is transmitted by four level transmitters located on the tank. For automatic switchover to occur, the 2/4 matrix signal coincident with the key switch in the RMT position is required. Level indication from each of these four channels is provided in the control room.

The non-safety-related refueling water storage tank level switches that were originally used to detect a refueling water storage tank low level and a refueling water storage tank high-high level have been replaced by a refueling water storage tank narrow-range level monitoring system. The refueling water storage tank narrow-range level monitoring system monitors the span between a point just below the dome bend line and the bottom of the overflow line. This span encompasses the range in which the refueling water storage tank wide-range level indicators are inaccurate due to the combined error of the indicating loops.

The refueling water storage tank narrow-range level monitoring system consists of an admittance type level probe, located in the manway at the top of the refueling water storage tank. The level probe is connected to a transmitter mounted on the platform of the refueling water storage tank. The transmitter is housed in a NEMA 4 enclosure along with a power supply, remote indicator, and adjustable setpoint relays. The transmitter supplies a 4 to 20 mA output signal which drives a channel on the refueling water storage tank wide-range level recorder in the control room. The refueling water storage tank wide-range level trend recorder chart paper has been replaced with appropriately scaled display, 0 to 100% for the refueling water storage tank wide-range level, and 90 to 100% for the refueling water storage tank narrow-range level. The adjustable setpoint relays are used to initiate the refueling water storage tank low level alarm, channel trip annunciators, and the refueling water storage tank high-high level alarm in the control room, and initiate local refueling water storage tank high-high level alarms at the entrance and at the bottom of the safeguard valve pit.

The purpose of the local valve pit alarms is to warn anyone in the valve pit or about to enter the valve pit, that a high-high level exists in the refueling water storage tank which could escalate into an overflow condition and that they should leave the area immediately.

The instrumentation for the recirculation phase is the same as that listed in Table 6.2-2 for initial injection.

6.2.2.1.3 Recirculation Phase

The coolant and refueling water spilled from the break and the water from the containment depressurization system (Section 6.3.1) collects in the containment sump, and part is returned to the reactor coolant system by the low-head safety injection pumps. The balance flows to the recirculation spray subsystem.

Because the injection phase of the accident is terminated before the refueling water storage tank is completely emptied, all pipes are kept filled with water before recirculation is initiated. Water level indication and alarms on the refueling water storage tank give the operator ample warning to terminate the injection phase while the operating pumps still have adequate net positive suction head (NPSH). These indications and alarms also inform the operator that sufficient water has been injected into the containment to allow the initiation of recirculation with the low-head safety injection pumps.

Two additional level indicators are provided for the containment sump that also indicate when injection can be terminated and recirculation initiated.

When steam dump cooldown is used for a small break in the reactor coolant system (4 inches and smaller), the steam is dumped to the condenser when outside power is available, or directly to the atmosphere when outside power is not available. As discussed in Section 14.5, the expected clad temperatures for break sizes 4-inch and smaller are limited to a value below which clad degradation is expected. When steam dump is initiated, the only activity that can be leaked into the steam is dumped to the condenser if outside power is available, in which case the air ejector radiation monitor provides additional information that activity carryover to the secondary side had not occurred as a result of the accident.

The redundant features of the recirculation loop include one low-head safety injection pump in each of two separate trains, with crossover capability at the discharge of each pump. Each pump takes suction through separate lines from the containment sump strainer. These suction lines are cross-connected prior to exiting the containment.

The design of the containment sump and piping configuration from the containment sump to the low-head safety injection pumps is illustrated in Figure 6.1-1.

After 1 day, the spray water collected is cold enough to reduce the temperature of the combined mass sufficiently for recirculation without flashing. All heat removal is through the recirculation spray subsystem. There are no heat exchangers in the safety injection system.

Those portions of the safety injection system located outside of the containment that are designed to circulate, under postaccident conditions, radioactively contaminated water collected in the containment, meet the following requirements:

1. Shielding to maintain radiation levels within the guidelines set forth in 10 CFR 100.
2. Collection of discharges from pressure-relieving devices into the drains aerated system for forwarding to the liquid waste disposal system.
3. Means to detect and control radioactivity leakage into the environs, within limits consistent with guidelines set forth in 10 CFR 100 and 10 CFR 50.67.

This criterion is met by minimizing leakage from the system. Recirculation loop leakage is discussed in Section 6.2.3.

6.2.2.1.4 Steam-Line Break Protection

A large break of a main steam system pipe causes an uncontrolled removal of heat that rapidly cools the reactor coolant, causing the insertion of positive reactivity into the core. Compensation is provided by the injection of borated water from the RWST. The isolation valves in the lines injecting into the reactor coolant system hot legs remain closed, ensuring that the safety injection flow is directed into the cold legs of the reactor coolant system.

In order to ensure a supply of RWST water to each unit's charging pumps in the unlikely event that a HELB (e.g., MSLB) outside of containment renders the affected unit's RWST or RWST supply line inoperable, a piping cross-connect is installed between the suction side of the charging pumps for Unit 1 and Unit 2 (Reference 4). Two parallel sets of normally closed trip valves, SI-TV-102A and SI-TV-102B and SI-TV-202A and SI-TV-202B, provide isolation between each unit's charging pump suction header during normal operation. A single steam line break (SLB) signal from either unit will automatically open a valve on each side of the cross-connect. This provides a suction path from the unaffected unit's RWST to the affected unit's charging pumps. If a unit is in refueling and the other unit is operating, a minimum allowable RWST level of 20.5% for the unit being refueled is required to shut down the operating unit. Check valves are installed to prevent a loss of inventory from the unaffected unit's RWST through the affected unit's broken charging pump suction line for breaks upstream of the check valves.

The containment response following a main steamline break was evaluated during the analyses performed for elimination of the boron injection tank. In 1983, Virginia Power requested a license amendment which allowed a reduction in the minimum required boric acid concentration of the boron injection tank (Reference 5). Reference 6 documented an evaluation of the MSLB containment response which was requested by NRC. The NRC, in the SER for the associated Technical Specifications changes (Reference 7), made these observations concerning the containment temperature effects of MSLB for Surry:

> The licensee has performed sensitivity studies to address the impact of reducing the BIT boron concentration on early MSLB energy release, and has concluded that the current equipment qualification temperature envelopes for the Surry plants are adequate. Since LOCA conditions dominate the containment functional design considerations, the licensee used the LOCA temperature profiles for post-accident equipment qualification in lieu of MSLB temperature profiles. Based on a review of the information submitted by the licensee, and because of the similarity of the licensee's request to other staff actions, we conclude that the licensee's proposal to eliminate the minimum boron concentration requirement in the BIT will not adversely affect the containment functional performance.

From this statement, it is concluded that containment temperature profiles associated with the large break LOCA analysis represent the limit approved by the NRC in Reference 7.

Downstream of the normally closed valves 1-SI-MOV-1890A and 2-SI-MOV-2890A and near the containment penetration area exists a beyond design basis (BDB) mechanical connection for the purpose of connecting a portable pump to inject borated/makeup water into the Reactor Coolant System (RCS) during a beyond design basis external event (BDBEE).

See Section 5.4 for MSLB evaluation.

6.2.2.2 **Components**

All associated components, piping, structures, and power supplies of the safety injection system are designed to conform with Seismic Class I criteria. Safety injection system components inside the containment are capable of withstanding or are protected from the differential pressure that may occur during the rapid containment pressure increase.

All motors, instruments, transmitters, and their associated cables located inside the containment are designed to function under postaccident temperature, pressure, and humidity conditions.

Internal wetted parts of safety injection system components are austenitic stainless steel, or other equivalent corrosion resistant materials, and hence are compatible with the spray solution over the full range of exposure in the postaccident regime.

The quality standards of all safety injection system components are given in summary form in Table 6.2-3.

6.2.2.2.1 Accumulators

The accumulators are pressure vessels filled with borated water and pressurized with nitrogen gas. During normal operation, each accumulator is isolated from the reactor coolant system by two check valves in series, only one of which is required for isolation. If the reactor coolant system pressure falls below the accumulator pressure, the check valves open and borated water is forced into the reactor coolant system. Mechanical operation of the swing-disk check valves by means of differential pressure is the only action required to open the injection path from the accumulators to the core via the cold leg.

The level of borated water in each accumulator tank is adjusted remotely as required during normal station operation. Refueling makeup water is added using the positive displacement hydrotest pump.

Water level may be reduced by draining to the RWST, primary drains tank or primary drain transfer tank. Samples of the solution in the accumulators are taken for periodic checks of boron concentration.

The accumulators are passive engineered safeguards because the nitrogen gas pressure forces injection; no external source of power or signal transmission is needed to obtain fast-acting, high-flow capability when the need arises. One accumulator is connected to each of the cold legs of the reactor coolant system.

The design capacity of the accumulators is based on the assumption that flow from one of the accumulators spills onto the containment floor through the ruptured loop. The flow from the two remaining accumulators provides sufficient water to fill the volume outside of the core barrel below the nozzles, the bottom plenum, and one-half of the core (see Figure 3.5-2).

The accumulators are carbon steel, clad with stainless steel, and designed to ASME Code, Section III, Class C. Redundant level and pressure indicators are provided with readouts on the control board. Each channel is equipped with high-level and low-level alarms. The margin between the minimum operating pressure and the design pressure provides a range of acceptable operating conditions within which the accumulator system meets its design core cooling objectives. The band is sufficiently wide to permit the operator to minimize the frequency of leakage compensating adjustments in the amount of contained gas or liquid.

The accumulator design parameters are listed in Table 6.2-4.

6.2.2.2.2 Pumps

Three safety injection/charging pumps, which are used as high-head safety injection system pumps, supply borated water to the reactor coolant system. The pumps are of the horizontal centrifugal type, driven by electric motors.

Two low-head safety injection pumps also supply water to the reactor coolant system. Table 6.2-5 lists the design parameters for the safety injection charging and low-head safety-injection pumps.

All pressure-containing parts of the pumps are chemically and physically analyzed, and the results are checked to ensure conformance with the applicable ASTM specifications. In addition, all pressure-containing parts of the pumps are liquid penetrant inspected in accordance with Appendix VIII of Section VIII of the ASME Code. The acceptance standard for the liquid penetrant test is USAS B31.1, Code for Pressure Piping, Case N-10. Parts of the pump in contact with borated water are stainless steel or equivalent corrosion-resistant material.

The pressure-containing parts of the pumps are castings conforming to ASTM A351 Grade CF8 or CF8M. Stainless steel forgings are procured per ASTM A182 Grade F304 or F316, or ASTM A336, Class F8 or F8M. Stainless steel plate is constructed to ASTM A240, Type 304 or 316. Bolting material conforms to ASTM A193. Materials such as weld-deposited Stellite or Colmonoy are used at points of close-running clearances in the pumps to prevent galling and to ensure continued performance capability in high-velocity areas subject to erosion.

Pump design is reviewed with special attention to the reliability and maintenance aspects of the working components. Specific areas include the evaluation of the shaft seal and bearing design to determine that adequate allowances have been made for shaft deflection and clearances between stationary parts.

Where the welding of pressure-containing parts is necessary, a welding procedure including joint detail was submitted for review and approval. The procedure includes evidence of qualification necessary for compliance with Section IX of the ASME Code, *Welding Qualifications*. This requirement also applies to any repair welding performed on pressure-containing parts.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The pressure-containing parts of the pump were assembled and hydrostatically tested to 1.5 times the design pressure for 30 minutes.

Each pump was given a complete shop performance test in accordance with Hydraulic Institute standards. The pumps were run at design flow and head, shut-off head, and three additional points to verify performance characteristics. Where net positive suction head is critical, this value was established at design flow by means of adjusting suction pressure.

6.2.2.2.3 Valves (General)

All parts of valves used in the safety injection system in contact with borated water are austenitic stainless steel or equivalent corrosion-resistant material. The motor operators on the injection line isolation valves are capable of rapid operation. Valves required to change position for the initiation of safety injection or isolation of the system have remote position indication in the control room.

Exceptional tightness is specified for the valves and, where possible, packless diaphragm valves are used (e.g., for instrument valves). Valves, except those that perform a control function, are provided with backseats that are capable of limiting leakage. Those valves that are normally open are backseated, with the exception of quarter-turn valves. The use of quarter-turn valves is limited to low pressure regions of the system, which helps minimize stem leakage, and the valves are not installed in a recirculation flowpath. Normally closed globe valves are installed with pressure under the seat to prevent the leakage of recirculated water through the valve stem packing. An exception to this preference includes the charging pump recirculation MOVs which are installed with pressure over the seat which assists closing thrust margin. The reversed configuration exposes the valve packing to the inlet pressure when the valve is closed.

The check valves that isolate the safety injection system from the reactor coolant system are installed adjacent to the reactor coolant piping to reduce the probability of a safety injection line rupture causing a LOCA.

The gas relief valves on the accumulators protect them from pressures in excess of the design value.

6.2.2.2.4 Motor-Operated Valves

The pressure-containing parts (body, bonnet, and disks) of the valves employed in the safety injection system are designed according to criteria established by the USAS B16.5 or MSS SP-66 specifications. The materials of construction for these parts are procured as per ASTM (S)A182, F316, or A351, Grade CF8M or CF8.

Radiographic inspection is conducted in accordance with the procedure outlined in ASTM E-94. Radiographic acceptance standards are outlined in ASTM E-71, E-186, or E-280, whichever is applicable, and meet the requirements of severity level 2, except that D, E, F, and G defects are not permissible. The body, bonnet, and disk are liquid penetrant inspected in accordance with ASME Code, Section III, paragraph N-627.

When a gasket is employed, the body-to-bonnet joint is designed as per ASME Code, Section VIII, or USAS B16.5, with a fully trapped, controlled compression, spiral-wound gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. The body-to-bonnet bolting and nut materials are procured per ASTM A193 and A194, respectively.

The bolt material for 2-SI-MOV-2869A and 2-CH-MOV-2287C is ASTM A564, Type 630, H1100.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The entire assembled unit was hydrotested as outlined by Manufacturers Standardization Society in the Valve and Fitting Industry, Specification 61 (MSS SP-61), with the exception that the test was maintained for a minimum period of 30 minutes. Failure of the test was cause for rejection.

The seating design is of the Darling parallel disk design, the Crane split wedge design, the Westinghouse flex wedge design, the Velan globe style design, the Xomox quarter-turn plug design, or the equivalent. Except for the Xomox valves, these designs have the feature of releasing the mechanical holding force during the first increment of travel. Thus, these motor operators have to work only against the frictional component of the hydraulic imbalance on the disk and against the packing box friction in the absence of a pressure locked condition. The disks are guided to prevent chattering and provide ease of disk movement. The seating surfaces are hard-faced (Stellite No. 6. or equivalent) to prevent galling and reduce wear.

The stem material is ASTM A276, Type 316, condition B. or precipitation hardened 17-4 PH stainless, procured and heat-treated to Westinghouse specifications.

These materials are selected because of their corrosion resistance, high-tensile properties, and their resistance to surface scoring by the packing. The valve stuffing box is designed with a lantern ring leakoff connection with a minimum of a full set of packing below the lantern ring and a maximum of one-half of a set of packing above the lantern ring; a full set of packing is defined as a depth of packing equal to 1.5 times the stem diameter. The experience with this stuffing box design and the selection of packing and stem materials has been very favorable in both conventional and nuclear power stations.

The motor operator is extremely rugged. The unit incorporates a hammerblow feature that allows the motor to impact the disks away from the fore- or backseat upon opening or closing. The hammer-blow feature not only impacts the disk but allows the motor to rapidly attain its operational speed.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The valves were assembled, hydrostatically tested, seat-leakage tested (fore and back), operationally tested, cleaned, and packaged as per specifications. In some cases, extension stems were used on motor-operated valves. These valves were operationally tested initially without the extension stems. The valves were operationally tested later with the extension stems, after installation in the unit. Manufacturing procedures employed by the valve supplier, such as hard facing, welding, repair welding, and testing, were submitted to Westinghouse for approval.

For those valves that must function on the safety injection signal, the following requirements originally applied: for valves up to and including 8-inch, the valve operator completes its cycle from one position to another in 10 seconds maximum. For valves over 8 inches, the valve cycling operation occurs at a rate of 49 in/min. For all other valves in the system, the following requirements originally applied: for valves up to and including 8-inch, the valve cycling operation occurs at a rate of 12 in/min and, for valves greater than 8-inch, the valve operator completes its cycle from one position to another in 120 seconds maximum.

Current allowable valve stroke times may exceed original purchase specifications. The current allowable valve stroke times are based on safety system response requirements and/or accident analysis and are considered when developing acceptance criteria to ensure that the valve performance does not degrade below the performance required by the safety system response requirements and/or accident analysis. The acceptance criteria are developed and the tests performed in accordance with the ASME Inservice Testing Program as required by 10 CFR 50.55a(f)4.

Several motor operated valves in the SI System have been modified to prevent valve pressure locking. The valves have been modified to relieve pressure that can be trapped between the gate valve disks. The following MOVs have been modified by drilling a hole in the upstream disk: 1-SI-MOV-1842, 2-SI-MOV-2842, 1-SI-MOV-1867C,D, 2-SI-MOV-2867C,D, 1-SI-MOV-1869A,B, 2-SI-MOV-2869B, 2-SI-MOV-2860A. The following MOVs have been modified by drilling a hole in the downstream disk: 1-RH-MOV-1720A,B, 1-SI-MOV-1860A,B, 2-SI-MOV-2860B. The following MOVs have been modified by installing a downstream equalization line: 1-SI-MOV-1890A,B, 2-SI-MOV-2890A,B (Reference 8).

Valves that must function against system pressure are designed so that they function with a pressure drop equal to full system pressure across the valve disk.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Tests to demonstrate the adequacy of valve motor operators to be functional after exposure to high temperatures, pressure, and radiation were conducted in two groups.

The first group was the exposure of valve motor operators to high temperatures and pressures. Tests were conducted in simulated containment pressures and temperatures characteristic of those predicted for an accident. The results were released in Proprietary WCAP 7410-L, submitted in January 1971.

Test conditions were as follows:

1. The valve operator was located inside a pressure vessel that was at approximately 300°F and 90 psig.
2. The valve operator was cycled approximately three times under simulated valve operating loads.
3. Pressures and temperatures were reduced in step changes to 285°F at 60 psig, 219°F at 20 psig, and 152°F at atmospheric pressure or less.
4. The valve operator was cycled approximately three times at each of the levels of change. Full recordings of pertinent data were taken throughout the test.
5. The valve unit was examined after completion of the test and operating data were compared to data before exposure.

The second test group was the radiation test on a motor from the valve operator. Test conditions were as follows:

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

1. Two production line motors were used for this test. One was exposed to a total of 1.5×10^8 rad of gamma radiation in approximately one month. The other motor was used for the final comparative analysis.
2. Both motors were tested for coil resistance by the Wheatstone bridge method, and for insulation resistance by meggering both before and after motor vibration and reversing operations.

The compatibility of construction materials with a postaccident solution of boric acid and sodium tetraborate decahydrate is discussed in WCAP-16596 (Reference 12).

The recirculation spray sump in containment is maintained wet to provide a water seal to reduce the potential for pressure locking the LHSI pumps containment suction MOV's (Reference 9).

6.2.2.2.5 Manual Valves

The stainless steel manual globe, gate, and check valves are designed and built in accordance with the requirements outlined in the motor-operated valve description above (Section 6.2.2.2.4).

The carbon steel valves are built to conform with USAS B16.5. The materials of construction of the body, bonnet, and disk conform to the requirements of ASTM A105, Grade II; A181, Grade II; or A216, Grade WCB or WCC. The carbon steel valves pass only non-radioactive gases and were subjected to hydrostatic test as outlined in MSS-SP-61, except that the test pressure was maintained for at least 30 minutes.

6.2.2.2.6 Vent Valves

High point vents have been installed at critical points in the suction lines of the charging (HHSI) pumps, and the discharge lines of the LHSI pumps where gasses could collect.

6.2.2.2.7 Accumulator Check Valves

The pressure-containing parts of these valve assemblies are designed in accordance with MSS SP-66. Parts in contact with the operating fluid are of austenitic stainless steel or of equivalent corrosion-resistant materials procured to applicable ASTM or Westinghouse specifications.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The cast pressure-containing parts were radiographed in accordance with the procedure outlined in ASTM E-94. Radiographic acceptance standards were as outlined in ASTM E-71, E-186, or E-280, whichever was applicable, and met the requirements of severity level 2, except that D, E, F, and G defects were not permissible. The cast pressure-containing parts, machined surfaces, finished hard facings, and gasket-bearing surfaces were liquid penetrant inspected per ASME Code, Section VIII, and the acceptance standard was as outlined in USAS B31.1, Code Case N-10. The final valves were hydrotested in accordance with MSS SP-61, except that the test pressure was maintained for at least 30 minutes. The seat leakage test was conducted in accordance with the manner prescribed in MSS SP-61, except that the acceptable leakage was 3 cm^3/hr/in. of nominal pipe diameter.

The valve is designed with a low pressure drop configuration, with all operating parts contained within the body, which eliminates those problems associated with packing glands exposed to boric acid. The clapper arm shaft is manufactured from 17-4 PH stainless steel heat-treated to Westinghouse specifications. The clapper arm shaft bushings were manufactured from Stellite No. 6 or other corrosion and wear resistant material. The various working parts were selected for their corrosion-resistant, tensile, and bearing properties.

The disk and seat rings were, manufactured from a forging. The mating surfaces are hard-faced with Stellite No. 6 or other corrosion and wear resistant material to improve the valve seating life. The disk is permitted to rotate, providing a new seating surface after each valve opening.

The valves are intended to be operated in the closed position, with a normal differential pressure across the disk of approximately 1600 psi. The valves remain in this position except for testing and accumulator discharge. Since the valve is not normally required to operate in the open position, and hence be subjected to flow induced wear or impact loads caused by sudden flow reversal, it is expected that this equipment will satisfactorily perform its required functions indefinitely with minimal maintenance.

When the valve is required to function, a differential pressure of less than 25 psid will shear any particles that may attempt to prevent the valve from functioning. Although the working parts are exposed to the boric acid solution contained within the reactor coolant loop, boric acid freeze-up is not expected because the boric acid concentration is relative low.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The experience derived from the check valves employed in the similar safety injection system of the Carolinas-Virginia Tube Reactor (CVTR) indicates that the system is reliable and workable.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The CVTR emergency injection system was normally maintained at containment ambient conditions and was separated from the main coolant piping by a single 6-inch check valve. A leak detection pot was provided at a proper elevation to accumulate any leakage coming back through the check valve. A level alarm provided a signal on excessive leakage. The pressure differential was 1500 psi and the system was stagnant. The valve was located 2 to 3 feet from the main coolant piping, which resulted in some heatup and cooldown cycling. The Carolinas-Virginia Tube Reactor went critical late in 1963 and operated until 1967. During that time, the level sensor in the detection sump never alarmed due to check valve leakage.

6.2.2.2.8 Accumulator Isolation Valves

The isolation valve at each accumulator is normally closed only when the reactor is intentionally depressurized. The only other times the isolation valve is closed is for testing or maintenance purposes, for which a time limitation is specified in the Technical Specifications. The valves, however, receive a signal to open when safety injection is initiated. The valve is designed to operate with full system differential pressure. The isolation valve is normally blocked opened by de-energizing the valve motor operators when the reactor coolant pressure exceeds 1000 psig. An alarm in the control room sounds if the valve is inadvertently closed. It is not expected that the isolation valve will have to be closed because of excessive leakage through the check valves.

When the reactor coolant system is being pressurized during the normal unit heatup operation, the check valves are tested for leakage as soon as there is about 100 psi differential across the valve. This test confirms the seating of the disk and whether or not there has been an increase in the leakage since the last test. When this test is completed, the discharge line isolation valves are opened and the reactor coolant system pressure increase continued. There should be no increase in leakage from this point on, since increasing reactor coolant pressure increases the seating force and decreases the probability of leakage.

6.2.2.2.9 Relief Valves

The accumulator relief valves are sized to pass nitrogen at a rate in excess of the accumulator gas fill-line delivery rate. The relief valves also pass water in excess of the expected leak rate, but this is not necessary, because the time required to fill the gas space gives the operator ample opportunity to correct the situation. For a maximum allowable inleakage rate, there are about 6.0 hours before water reaches the relief valves. Prior to this, level and pressure alarms would have been actuated.

6.2.2.2.10 Valve Leakage Limitations

The following valve information is presented as the design information from the original equipment specifications. These valves are currently tested in accordance with ASME Inservice

Testing Program for monitoring valve performance as required by 10 CFR 50.55a(f) and replaced in accordance with current approved equipment specifications.

Exceptional tightness is specified for all valves, and packless diaphragm valves are used where possible (such as for instrument valves).

Normally open valves have backseats that limit stem leakage.

Normally closed globe valves are installed with pressure under the seat to prevent stem leakage from the more radioactive fluid side of the seat.

The manufacturer seat leakage testing for the valves was conducted in accordance with the manner prescribed in MSS-SP-61 except the test pressure was maintained for a minimum of 5 minutes. The seat leakage rate for globe, gate, and self actuated check valves was required to be less than 3 cc/hour/inch of nominal valve size. The seat leakage rate for diaphragm valves was required to have zero seat leakage.

Leakage from components of the recirculation loop, including valves, is discussed in Section 6.2.3.10.

6.2.2.2.11 Pump and Valve Motors

Electrical insulation systems for motors outside containment are supplied and tested in accordance with USASI, IEEE, and NEMA standards. Temperature rise design selection is such that normal long life is achieved even under accident loading conditions.

Motors for the valves inside the containment are designed to withstand containment environment conditions following the LOCA so that the valves can perform the required function during the recovery period.

Containment motors that must operate during and/or after the postulated accident are designed for continuous service in the postaccident containment environment. Periodic operations of the motors and tests of the insulation ensure that the motors remain in a reliable operating condition. The only motors of the safety injection system that must operate inside the containment are valve motors.

Although these motors, which are provided only to drive engineered safety features equipment, are normally run only for test, the design loading and temperature rise limits are based on the accident conditions.

Normal design margins are specified for these motors to make sure the expected lifetime includes allowance for the occurrence of accident conditions.

6.2.2.2.12 Piping

Safety injection system piping in contact with borated water is austenitic stainless steel. Piping joints are welded, except for the flanged connections at the relief valves, flow elements, and safety injection pumps.

The piping beyond the accumulator stop valves is designed for reactor coolant system conditions (2485 psig, 650°F). All other piping connected to the accumulator tanks is designed for at least 700 psig and 400°F.

The safety injection charging pump suction piping from the refueling water storage tank is designed for low-pressure losses to meet NPSH requirements of the pumps.

The safety injection high-pressure branch lines are designed for high-pressure losses to limit the flow rate out of the branch line, which may have ruptured at the connection to the reactor coolant loop. The system design incorporates the ability to isolate the safety injection charging pumps on separate headers so that full flow from at least one pump is ensured should a branch line break.

The piping is designed to meet the minimum requirements set forth in the USAS B31.1-1955 Code for Pressure Piping, USAS B36.10 and B36.19, ASTM Standards, supplementary standards, and additional quality control measures.

Minimum wall thicknesses are determined by the formula found in Section 1 of the USAS B31.1-1955 Code for Pressure Piping. This minimum thickness is increased to account for the manufacturer's permissible tolerance of –12.5% on the nominal wall and an 8% allowance for bending. Purchased pipes and fittings have a specified nominal wall thickness that is no less than the sum of that required for pressure containment, pipe bending, mechanical strength, and manufacturing tolerance.

Special attention is directed to the piping configuration at the pumps, with the objective of minimizing pipe-imposed loads at the suction and discharge nozzles.

Piping is supported to accommodate expansion due to temperature changes and hydraulic forces during an accident.

The materials for pipes and fittings are procured in conformance with requirements of the ASTM and USASI specifications. Materials are verified for conformance to specification and documented by certification of compliance to ASTM material requirements. Specifications impose additional quality control on the suppliers of pipes and fittings, as listed below:

1. Provided copies of analyses performed on both the purchased pipes and fittings.
2. Pipe branch lines between the reactor coolant pipes and the isolation stop valves conform to ASTM A376 and meet the supplementary requirement S6 for ultrasonic testing.
3. Fittings conform to the requirements of ASTM A403.

Shop fabrication of piping subassemblies is performed in accordance with specifications that define and govern material procurement, detailed design, shop fabrication, cleaning, inspection, identification, packaging, and shipment.

Welds for pipes sized 2.5 inches and larger are butt welded. Reducing tees are used where the branch size exceeds one-half of the header size. Branch connections of sizes that are equal to or less than one-half of the header size are of a design that conforms to the USASI rules for reinforcement set forth in the USAS B31.1 Code for Pressure Piping. Bosses for branch connections are attached to the header by means of full-penetration welds.

Welding was performed by welders and welding procedures qualified in accordance with ASME Code, Section IX, *Welding Qualifications*. The shop fabricator was required to submit all welding procedures and evidence of qualifications for review and approval before release for fabrication. Welding materials used by the shop fabricator required prior approval.

High-pressure piping butt welds containing radioactive fluid, at greater than 600°F temperature and 600 psig pressure, were radiographed. The remaining piping butt welds were randomly radiographed. The technique and acceptance standards were those outlined in paragraphs N-624.2 and N-625.3 of ASME Code, Section III. In addition, butt welds were liquid penetrant examined in accordance with the procedure of ASME Code, Section III, paragraph N-627.2, and the acceptance standard as defined in paragraph N-627.3. Finished branch welds were liquid penetrant examined on the outside, and the root passes were for sizes 6-inches and larger, and for schedule 80S and heavier for all sizes.

A postbending solution anneal heat treatment was performed on hot-formed stainless steel pipe bends. Completed bends were then completely cleaned of oxidation from affected surfaces. The shop fabricator was required to submit the bending, heat treatment, and cleanup procedures for review and approval before release for fabrication.

General cleaning of completed piping subassemblies (inside and outside surfaces) was governed by basic ground rules set forth in the specifications. For example, these specifications prohibited the use of hydrochloric acid and limited the chloride content of service water and demineralized water.

The packaging of the piping subassemblies for shipment was done so as to preclude damage during transit and storage. Openings were closed and sealed with tight-fitting covers to prevent the entry of moisture and foreign material. Flange facings and weld end preparations were protected from damage by means of wooden cover plates and were securely fastened in position. The packing arrangement proposed by the shop fabricator was subject to approval.

6.2.2.2.13 LHSI Strainer Assembly

The LHSI strainer assembly is designed to provide filtered borated water to both LHSI pumps during the recirculation mode. The strainer assembly consists of a number of modules which channel water to the pump suction. Modules are connected to each other by flexible metal seals. Seal closure frames with Metex seals are installed over existing flexible metal seals. The seal closure frame assemblies form the seal between adjacent strainer modules. Each module contains a number of fins which filter the water flowing into the modules. Each fin contains a number of holes 0.0625-inch (nominal) in diameter. Perforations on the strainer fins prevent particles larger than 0.06875-inch (0.0625-inch plus 10 percent) from entering the LHSI System. The total perforation area is large enough to allow sufficient flow to the suctions of the LHSI pumps to meet NPSH requirements. In addition, particles larger than 0.06875 inches were evaluated in response to gaps identified in the strainer assembly. As part of the evaluation, it was assumed that 1% of the total generated particles between 0.06875 inches (0.0625 inches plus 10 percent) and 0.1375 inches (0.125 inches plus 10 percent) would pass through the strainer. It was determined that these particles would not impact the performance of downstream components.

The LHSI strainer assembly consists of two trains which traverse along the containment wall on both sides of the sump. Each suction opening is connected to the modules via the strainer header. The strainer header is connected to each suction opening by a flanged transition adapter. The OD of the strainer header is machine cut and slip-fitted in to the new adapter ensuring that the gaps between the piping and the adapter do not exceed 0.0625 inches.

The strainer assembly is designed and fabricated to the requirements of ASME Section III, Subsection NF, Class 3. All material used in the construction of the strainer assembly is austenitic stainless steel.

The strainer assembly is capable of withstanding the full debris loading in conjunction with all design basis conditions without collapse or structural damage.

A 12-inch line provides a cross connection between the two 12-inch lines on the suction of the low-head safety injection pumps. Each of the two 12-inch LHSI suction pipes has its own suction opening connected to the strainer header. The strainer header is slip fit in to the suction opening located in the containment sump via a flanged transition adapter piece.

The design of the LHSI strainer assembly is similar to the design of the RS strainer assembly. Refer to Section 6.3.1.3 for further information.

6.2.2.3 **Electrical Supply**

Details of the normal and emergency power source for the safety injection system are presented in Chapter 8.

6.2.2.4 **Protection Against Dynamic and Environmental Effects**

The high-head safety injection lines penetrate the containment adjacent to the auxiliary building.

For most of the routing, these lines are outside each reactor coolant loop cubicle and hence are protected from missiles originating within these areas. Each line penetrates the cubicle wall near the injection point to the reactor coolant pipe. In this manner, maximum separation, and hence protection, is provided in the coolant loop area.

Coolant loop supports are designed to restrict the motion in one loop due to rupture in another to about 0.1 inch, whereas the attached safety injection piping can sustain a three-inch displacement without exceeding the working stress range. The analysis assumes that the injection flow to the ruptured loop is spilled on the containment floor.

Hangers, stops, and anchors are designed in accordance with USAS B31.1 *Code for Pressure Piping,* and ACI 318 *Building Code Requirements for Reinforced Concrete,* which provide minimum requirements on materials, design, and fabrication with ample safety margins for both dead and dynamic loads over the life of the equipment. Specifically, these standards require the following:

1. All materials used are in accordance with ASTM specifications, which establish quality levels for the manufacturing process, minimum strength properties, and for test requirements that ensure compliance with the specifications.
2. Qualification of welding processes and welders for each class of material welded and for types and positions of welds.
3. Maximum allowable stress values are established that provide an ample safety margin on both yield strength and ultimate strength.

In the event of the hypothetical double-ended severance of a reactor coolant pipe, the functional integrity of the safety injection system connections to the remaining reactor coolant loops is not impaired. This integrity is established and maintained by the application of the following design criteria:

1. The reactor vessel, steam generators, and safety injection pumps are supported and restrained to limit their movement under pipe break conditions (including a double-ended reactor coolant pipe rupture) to a maximum amount, which ensures the integrity of the main steam and feedwater piping. The safety injection piping to the intact loops is designed to accommodate the limited movement of the loop components without failure.
2. The safety injection piping serving each loop is anchored at the missile barrier in each loop to restrict incident damage to that portion of piping downstream of this point. The anchorage is designed to withstand without failure the thrust force on the safety injection branch line severed from the reactor coolant pipe discharging safety injection flow to the containment, and to withstand a bending moment equivalent to that which produces failure of the safety injection piping under the action of free-end discharge or motion of the broken reactor coolant pipe to which the safety injection piping is connected. This anchorage prevents possible failure upstream from the support point where the branch line ties in to the safety injection piping header.

The safety injection system operating equipment located outside the containment is not required to operate in the steam-air environment produced by the accident.

Motors, instruments, transmitters, and their associated cables and penetrations located inside the containment are designed to function under postaccident temperature, pressure, and humidity conditions for the length of time required.

6.2.3 Design Evaluation

6.2.3.1 Range of Core Protection

The measure of effectiveness of the safety injection system is the ability of the pumps and accumulators to keep the core flooded or to reflood the core rapidly where the core has been uncovered for postulated large-area ruptures. The result of this performance is to sufficiently limit any increase in clad temperature below a value where emergency core cooling objectives are met, as discussed in Section 6.2.1. The range of core protection as a function of break diameter provided by the various components of the safety injection system is presented in Figure 6.2-2.

Figure 6.2-2 was developed from the results of the LOCA studies presented in Section 14.5. Simulations of a sufficient number of break sizes were performed to demonstrate that the safety injection components meet the emergency core cooling requirements. The injection from the following combination of components was analyzed as discussed below:

Bar A - One safety injection charging pump.

Bar B - One safety injection charging pump and three accumulators.

Bar C - One low-head safety injection pump and two accumulators.

Bar D - One safety injection charging pump and three accumulators (small break LOCA). One safety injection charging pump, one low-head safety injection pump, and two accumulators (large break LOCA).

Note: For all of the cases, one low-head safety injection pump is required for long-term recirculation.

No credit is taken for the accumulator that is attached to the ruptured leg in the case of a cold-leg large break LOCA.

With minimum onsite emergency power available, the emergency core cooling equipment available automatically is represented by Bar D (one-out-of-three safety injection charging pumps, and three-out-of-three accumulators for a small cold-leg break; one-out-of-three safety injection charging pumps, one-out-of-two low-head safety injection pumps, and two-out-of-three accumulators for a large cold-leg break, and three-out-of-three accumulators for a hot-leg break). With these systems, the calculated maximum fuel cladding temperature is within the limits specified in 10 CFR 50.46, which meet the emergency core cooling design objectives for all break sizes up to and including the double-ended severance of the reactor coolant pipe (Section 14.5).

The three combinations (Bars A, B, and C) represent degraded cases with operation of less than the installed emergency core cooling equipment. These cases are shown only to present the capability of individual portions of the system and to demonstrate the overall margins of the system. The operation of one safety injection charging pump together with two accumulators is probably capable of providing protection over a considerably greater range than shown. However, the analysis has only considered breaks up to the 8-inch diameter.

Bar D, which is the combination of the safety equipment in Bars B and C, and which also represents the minimum engineered safeguards available automatically, provides protection as shown over the complete range of break sizes up to and including the complete circumferential fracture of a reactor coolant pipe.

For the small range of break sizes up to 2 inches, as shown in Bar A, the action of one safety injection charging pump acting alone is sufficient to maintain enough core water inventory to ensure continued core cooling.

6.2.3.2 **Borated Water Injection Chemistry**

During the injection of emergency cooling water into the reactor coolant system following a LOCA, the concentration of boron will vary depending on the depressurization history of the reactor. If depressurization were slow, the high-head pumps would inject boric acid at a concentration greater than 2300 ppm, which would be diluted by the coolant remaining in the system. Rapid depressurization would bring about early injection of water containing boric acid at a concentration greater than 2250 ppm from the accumulators. When recirculation begins, the average concentration of boric acid is (and will remain) at a concentration that will maintain the core subcritical.

The concentrations of other materials, including chlorides, are quite low in this solution, corrosion products being generally insoluble in a basic solution. Assuming 50% of the maximum core inventory is released to containment after a LOCA, the principal fission product in the sump (assuming a gross core failure) would be iodine at a range between approximately 1.6 to 1.9 ppm for 500 days of operation and approximately 3.0 to 3.6 ppm for 1000 days of operation. The temperature of the sump water is reduced below 150°F, under normal operating conditions with a minimum of two recirculation coolers in operation, after a relatively short period of time (i.e., a few hours). Below 150°F, chloride stress corrosion does not constitute a problem.

6.2.3.3 **Chemical Additives**

Containment transient analyses show that the containment spray, having a pH between 4.25 and 4.75, will be used for approximately 1½ hours if minimum safeguards operate and approximately 50 minutes if normal safeguards operate. During this period, the containment will be cooling from 280°F to approximately 140°F. At the end of the initial containment cooling period, lasting no longer than approximately one hour, the recirculation spray system will continue in service for an indefinite period; however, the pH of the recirculating spray fluid should be between 7.0 and 9.0 during the long-term postaccident period and further addition of chemical additives is not contemplated.

Sodium Tetraborate Decahydrate stored inside containment is a white crystalline chemical in granular form. The NaTB is stored inside baskets which contain the chemical until it is dissolved by the containment sump water. To eliminate particulate matter from any potential source, the containment spray subsystem includes a strainer on the suction side of the containment spray pumps. This strainer will have openings smaller than the smallest spray nozzles, and therefore will remove any particulate matter from the containment spray flow that might prevent the system from functioning. Additionally, using NaTB as a buffer does not result in any different precipitates than those that form with the original NaOH buffer and the amount of precipitates is reduced, resulting in lower strainer head losses. Therefore, the functioning of the system will not be impaired because of precipitation.

The major construction materials that will be exposed to the containment spray, and the corrosion or deterioration rates for each under maximum exposure conditions, are listed in Table 6.2-7.

The materials adversely affected by the containment spray are aluminum and zinc.

The time-temperature exposure conditions under which these materials will be exposed to the containment spray are from approximately 50 minutes to 1½ hours, with the temperature decreasing from 280° to 140°F.

The materials will also be exposed to the recirculation sprays, which have a pH between 7.0 and 9.0 for the postaccident recirculation period with the temperature at approximately 140°F.

The consequence of corrosion and/or deterioration on materials with regard to postaccident operation of the engineered safeguards is negligible because components of the engineered safeguards are constructed of stainless steel.

The corrosion rate of stainless steel is low enough in the spray to be of no practical concern (Reference 1).

Insulated, safety-related cables feed power to the engineered safeguards equipment. The safety-related insulation is impervious to the chemical spray solution. Therefore, the supply of power to the engineered safeguards components will not be impaired.

No additional hazards will be generated by the deterioration or corrosion of the materials in the containment because materials of construction, other than aluminum and zinc, are either impervious to the chemical additive spray or painted with chemical-resistant coatings. The coatings have been successfully tested under design-basis accident conditions of irradiation and high-temperature chemical spray to ensure that they will remain intact.

6.2.3.4 **System Response**

To provide protection for large-area ruptures in the reactor coolant system, the safety injection system must respond by rapidly reflooding the core following the depressurization and core voiding that is characteristic of large area ruptures. The accumulators act to perform the rapid reflooding function with no dependence on the normal or emergency power sources and also with no dependence on the receipt of an actuation signal.

The operation of this system with two of the three available accumulators delivering their contents to the reactor vessel (one accumulator spilling through the break) prevents fuel clad melting and limits the metal-water reaction to an insignificant amount (less than 1%).

The function of the safety injection pumps is to complete the refill of the vessel and supply water for long-term core cooling. Moreover, there is sufficient excess water delivered by the accumulators to tolerate a delay in starting the pumps.

Initial response of the injection systems is automatic, with appropriate allowances for delays in the actuation of circuitry and active components. The active portions of the injection systems are automatically actuated by the safety injection signal (Chapter 7). In addition, manual actuation of the entire injection system and individual components can be accomplished from the control room. In the analysis of system performance, delays in reaching the programmed trip points and in the actuation of components were conservatively established on the basis that only emergency onsite power was available.

The starting sequence of the safety injection charging pumps, the low-head safety injection pumps, and the related emergency power equipment is designed so that the delivery of the full rated flow is reached within 25 seconds after the process parameters reach the setpoints for the injection signal (Section 7.2).

For the small-break analysis, an additional delay time is allowed to account for the receipt of a safety injection signal, from low pressurizer pressure.

6.2.3.5 **Single-Failure Analysis**

A single-active-failure analysis is presented in Table 6.2-8. All credible active system failures are considered. The analysis of the LOCA presented in Section 14.5 is consistent with the single-failure analysis.

The analysis is based on the worst single failure (generally a pump failure) in the safety injection system. The analysis shows that the failure of any single active component does not prevent fulfilling the design function; also, operator action is not required to correct the malfunction.

In addition to the single-active-failure capability, an alternate flow path is available to maintain core cooling if any part of the recirculation flow path becomes unavailable. The procedure followed to establish the alternate flow path also isolates the spilling line.

Failure analyses of the emergency power supply under LOCA conditions are described in Section 8.5.

6.2.3.6 **Reliance on Interconnected Systems**

Though the safety injection system relies on support systems, such as service water, component cooling water and electrical interfaces, the flow of the water via the safety injection pumps during the injection phase is not dependent on any portion of other interconnected systems with the exception of the suction line from the refueling water storage tank. During the recirculation phase of the accident for small breaks, suction to the safety injection charging pump is provided by the low-head safety injection pumps.

To maintain the containment subatmospheric, spray recirculation and cooling must be continued following a LOCA. Initially, spray recirculation is continuous, but as the core residual heat level decreases, the recirculation is reduced and, eventually, the system may be operated intermittently.

Since heat removal from the containment must be accomplished initially through the containment spray and recirculation spray subsystem, and since this represents a more than adequate heat removal mechanism for the containment, the use of heat exchangers in the low-head safety injection system for cooling is not required. The low-head safety injection system operates to provide long-term core cooling with no heat exchangers in the system by using water from the containment sump.

6.2.3.7 **Shared Function Evaluation**

Table 6.2-9 is an evaluation of the main components, which have been previously discussed, and a brief description of how each component functions during normal operation and during an accident.

6.2.3.8 **Passive Systems**

The accumulators are a passive safety feature, in that they perform their design function in the total absence of an actuation signal or power source. The only moving parts in the accumulator injection train are in the two check valves. A discussion of the design of the accumulator check valves and isolation valves is provided in Sections 6.2.2.2.7 and 6.2.2.2.8, respectively.

The accumulators are able to accept leakage from the reactor coolant system without any effect on their availability. Table 6.2-10 indicates what inleakage rates, over a given time period, require a level adjustment at the end of the time period. In addition, these rates are compared to the maximum allowed leak rates for manufacturing acceptance tests (36 cm^3/hr, i.e., 3 cm^3/hr per inch of pipe diameter).

The accumulators are located inside the reactor containment and protected from the reactor coolant system piping and components by missile barriers. A release of the gas charge in the accumulators would cause an increase in the containment peak pressure of approximately 0.2 psi. This release of gas has been included in the containment pressure analysis for the LOCA (Section 14.5).

During normal operation, the flow rate through the reactor coolant piping is approximately 2.6 times the maximum flow rate from an accumulator during injection. Therefore, fluid impingement on reactor vessel components as a result of accumulator discharge is not restrictive during the actuation of the accumulators.

6.2.3.9 **Emergency Flow to the Core**

Special attention is given to factors that could adversely affect the accumulator and safety injection flow to the core. These factors are:

1. Steam binding in the core, including flow blockage due to loop sealing.
2. Loss of accumulator water during blowdown.
3. Short circuiting of the accumulator discharge from the core to another part of the reactor coolant system.

6.2.3.10 **External Recirculation Loop Leakage**

Table 6.2-6 summarizes the original design maximum potential leakage from leakage sources in the recirculation loop through the low-head safety injection pumps, and through the safety injection charging pumps. The actual allowable leakage for each individual component can exceed the original criteria established in Table 6.2-6.

Leakage detection exterior to the containment is achieved through the use of sump-level detection. The auxiliary building sump pumps start automatically in the event that liquid accumulates in the sump and an alarm in the control room indicates that water has accumulated in the sump. A level switch is installed in the safeguards valve pit cubicle which alarms in the main control room with pumps used as necessary to transfer fluid to the liquid waste system. Valving is provided to permit the operator to isolate individually the low-head safety injection pumps.

The injection line piping is arranged so that a water seal is provided upstream of the valves located outside the containment, and this piping can be isolated from the containment. Thus, outleakage of air from the containment to the refueling water storage tank and hence to the atmosphere is prevented.

6.2.3.11 **Pump NPSH Requirements**

To ensure adequate NPSH for the LHSI and RS systems, a combination of flow restriction, recirculation flow feedback, and spray header nozzle plugging designs are included in the present system designs.

6.2.3.11.1 Low-Head Safety Injection Pumps

The net positive suction head of the low-head safety injection pumps is evaluated for both the injection and recirculation phases of the design-basis accident. Recirculation operation gives the limiting NPSH requirement, and the net positive suction head available is determined from the containment pressure and sump water level, pump water vapor pressure and the pressure drop through the strainer assembly to the pumps.

Each of the three low-head safety injection pump discharge lines to the cold leg loops contains a cavitating venturi that limits flow to prevent pump runout and ensures that the required net positive suction head will be met for all phases of operation following a LOCA.

During the injection phase, the low-head safety injection pump flow rate will vary with reactor coolant system pressure, containment pressure, and refueling water storage tank level. During the recirculation mode, the low-head safety injection pump flow will vary with reactor coolant system pressure, the vapor pressure (and hence temperature) of the sump water, and injection path (cold leg or hot leg). Evaluation of the low-head safety injection systems show that a single low-head safety injection pump will deliver the necessary low-head core cooling flow for any postulated set of accident conditions during the injection phase or the recirculation mode phase.

The refueling water storage tank level setpoint to initiate the automatic switchover of the low-head safety injection pumps from taking a suction on the refueling water storage tank to taking a suction from the containment sump strainer is consistent with the containment spray pump and low-head safety injection pump flow rates. Section 6.3.1 presents the setpoints used in the analysis.

The refueling water storage tank temperature will be maintained below 45°F. It is conservative to use the upper extreme for the NPSH analysis, since refueling water storage tank water is used as the subcoolant to the outside recirculation spray pumps. The upper extreme is also conservative for the depressurization analysis because it is less effective as a heat sink.

The analysis of available NPSH for the LHSI pumps during recirculation is performed with the GOTHIC computer program as described in Section 5.4. The analysis is similar to that performed in Section 5.4, except that the energy flow to the containment sump is maximized instead of the energy flow to the containment atmosphere as is done for containment pressurization and depressurization analyses. The analysis maximizes the sump water vapor pressure and minimizes the containment pressure. Thus, a conservatively low available NPSH is calculated.

The parameters which are used in the transient available NPSH calculation for the LHSI pumps are specified in the Table 6.2-11. The results of the analyses are summarized in Table 6.2-12.

The transient available NPSH is shown on Figure 6.2-3. The containment sump water level is also shown on the figure. The NPSH analyses account for the 12" Incore Sump Room drain in the determination of containment water level. The available NPSH transient begins when the LHSI pump suctions are switched to the sump (i.e., start of recirculation mode). The minimum available NPSH for these pumps is calculated for minimum ESF available following a DEPSG. Under these conditions, the water temperature is maximized by the break location assumption and the sump water cooling is minimized since only one train of containment spray and recirculation spray cooling are available. The containment pressure and sump water vapor pressure for the analysis is shown in Figure 6.2-4. The sump water temperature is shown on Figure 6.2-5. The recirculation spray heat exchanger duty is shown in Figure 6.2-6.

6.2.3.11.2 Safety Injection Charging Pumps

The net positive suction head for the safety injection charging pumps is evaluated for both the injection and recirculation phases of the design-basis accident.

The end of injection phase operation gives the limiting NPSH requirement, and the net positive suction head available is determined from the elevation head and vapor pressure of the water in the refueling water storage tank, and the pressure drop in the suction piping from the tank to the pumps.

6.2.3.11.3 Recirculation Spray Pumps

A discussion of the recirculation spray pump requirements is found in Section 6.3.1.4.

To provide cold water injection to the outside recirculation spray pumps, a 2.5-inch line with an orifice is rerouted from each 10-inch containment spray line inside containment and is hard piped to the respective outside recirculation spray strainer header. A restriction orifice in this bleed line results in a flow of approximately 310 gpm (actual flow varies with containment conditions) of chilled water from the refueling water storage tank to the outside pump suction. This piping is inside containment and designed to withstand seismic effects and water hammer. The containment spray pump that provides the water to the pump suction for a given outside recirculation spray pump is powered from the same emergency bus as that outside pump.

Each inside recirculation spray subsystem includes a minimum analyzed flow back to the pump suction of 300 gpm of recirculation spray water from the outlet of its inside spray cooler. The piping runs inside the containment and is designed for seismic effects and water hammer. A restriction orifice in the 2.5-inch line provides the desired minimum 300 gpm flow back to the pump suction. Material and installation are consistent with the design for the recirculation spray subsystem.

The inside recirculation spray pumps were originally designed to pump a 3500 gpm flowrate, however, analysis has shown that 3100 gpm is adequate for containment response to meet the requirements during a design basis accident. With a minimum of 3100 gpm inside recirculation pump flowrate the spray nozzle flow will be a minimum of 2800 gpm for each of the inside pump spray headers.

To limit the flowrate of the outside recirculation spray pumps to approximately 2900 gpm, additional flow restriction has been created by plugging nozzles and adding restriction orifices.

The results of the NPSH analysis for the inside and outside recirculation spray pumps are shown on Table 6.2-13.

6.2.3.12 **Combustible Gas Control in Containment Following a DBA**

6.2.3.12.1 Design Evaluation

The hydrogen recombiner system is designed to maintain the hydrogen concentration in the containment structure below 4 volume percent following a DBA.

Per References 11 and 12, the hydrogen recombiner system is no longer credited in the design basis or safety analysis. However, the system continues to be used in the Emergency Operating Procedures (EOPs) and is maintained and periodically tested.

The internal design of the containment structures allows air to circulate freely. All cubicles and most compartments within the containment are provided with openings near the top as well as openings in the floor to allow air circulation. Convective mixing in conjunction with containment spray assures a uniform mixture of hydrogen in the containment.

Containment system experiment tests (References 2 & 3) have verified that adequate mixing of the containment atmosphere is achieved by the CSS.

6.2.3.13 **Combustible Gas Control in Containment During Non-Accident Conditions**

The portable non-safety Passive Autocatalytic Recombiner (PAR) will be used for the purpose of controlling transient levels of hydrogen in the containment’s atmosphere during normal operation. When in use, the passive recombiner is attached with wire rope to existing grating located over a reactor coolant pump cubicle. The recombiner may be stored in either Unit’s containment until needed.

The PAR was designed for Advanced Light Water Reactor (ALWR) application and is completely passive in operation, requiring no power or other support systems to serve its function. The PAR device consists of a stainless steel enclosure providing both the structure for the device and support for the catalyst material. The enclosure is open on the bottom and top and extends above the catalyst elevation to provide a chimney effect. The PAR is self starting even at room temperature with hydrogen and oxygen at concentrations far below flammability levels. The catalyst material is contained within cartridges mounted vertically within the enclosure with open gas flow channels between them. The pellets are non-soluble and will not contribute to sump pH problems. The aluminum oxide ceramic pellets are doped with palladium particles and feature a coating which has water proofing properties. The aluminum oxide ceramic pellets will themselves not generate any hydrogen from corrosion. Some pellets may crack under the high temperatures expected during severe accidents, but are not expected to migrate out of their cartridge. The PAR is self feeding, with recombination rate increasing with increasing concentrations.

During operation, the air inside the recombiner is heated by the recombination process, causing it to rise by natural convection. As is rises, replacement air is drawn into the recombiner through the bottom of the PAR and heated by the exothermic reaction, forming water vapor, and exhausted through the chimney where the heated gases mix with the containment atmosphere. A 140-176°F temperature rise across the PAR is expected for every 1% H_2 in the air. At a hydrogen concentration of 0.8%, the device will generate approximately 2500 Btu/hr. This additional heat load will pose a negligible impact on the existing containment ventilation arrangement.

6.2.4 Tests And Inspections

The Safety Injection System is subject to the applicable inservice inspection and inservice testing requirements of the ASME Code, as required by 10 CFR 50 (Code of Federal Regulations, Title 10, Part 50). Other testing and inspections are conducted to ensure availability of equipment.

6.2.4.1 **Tests**

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

6.2.4.1.1 Preoperational Component Testing

Preoperational performance tests of safety injection system components were performed in the manufacturer’s shops. The pressure-containing parts of the pumps were hydrostatically tested in accordance with paragraph UG-99 of Section VIII of the ASME Code. Each pump was given a complete shop performance test in accordance with Hydraulic Institute standards. The pumps were run at design flow and head, shutoff head, and at additional points to verify performance characteristics. Net positive suction head was established at design flow by means of adjusting suction pressure for a representative pump. This test was witnessed by qualified Westinghouse and Vepco personnel.

The remote-operated valves in the safety injection system are motor or air operated. Shop tests for each valve included a hydrostatic pressure test, leakage tests, a check of opening and closing time, and verification of torque switch and limit switch settings. The ability of the operator to move the valve with the design differential pressure across the gate was demonstrated by opening the valve with an appropriate hydrostatic pressure on one side of the valve.

The recirculation piping and accumulators were initially hydrostatically tested at 150% of design pressure. The service water and component cooling water pumps were tested before initial operation.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

6.2.4.1.2 Preoperational System Testing

After hot functional testing and before initial fuel loading, the safety injection system was operationally tested. These tests included individual pump full-flow tests, accumulator operation, and complete system operational flow tests, with the reactor head removed. The purpose of this test was to demonstrate the proper functioning of the instrumentation and actuation circuits and to evaluate the dynamics of placing the system in operation. Water was supplied from the refueling water storage tank for this series of tests. The actuation of the pressurizer low level and pressure signals initiates the automatic start-up of the safety injection system.

The operability of the accumulators was checked by closing the stop valve, raising the pressure in the accumulator, and then opening the stop valve and observing the accumulator level change to provide an indication of system delivery. An additional check on system delivery can be made by observing the pressurizer level rise.

6.2.4.1.3 Refueling Tests

Portions of the safety injection system that can not be tested during normal plant operation are verified to operate properly through a series of tests during refueling. The refueling tests, in combination with the tests performed during normal plant operation, are used to demonstrate proper automatic operation of the safety injection signal. The tests are considered satisfactory if control board indication and visual observations indicate that all components have operated and sequenced properly. The automatic actuation circuitry, valves, and pump circuit breakers are also checked during these tests.

Back leakage through the accumulator discharge line check valves is monitored by opening the remote test valves in test lines between the remote stop valves and check valves. Flow through the test lines is measured to ascertain that these valves seat whenever the reactor system pressure is raised.

6.2.4.1.4 Normal Operation

Each active component of the safety injection system may be individually actuated on the normal power source at any time during the operation of the unit to demonstrate operability.

The chemical and volume control system charging pumps serve as the high-head safety injection pumps. As such, the operability of any pump can be demonstrated while the unit is at power. Demonstration tests can be performed at other times by employing the minimum flow recirculation line that returns to the discharge line of the volume control tank.

The test of the low-head safety injection pumps employs the minimum flow recirculation test line that returns to the refueling water storage tank. Remote-operated valves and actuation circuits are also periodically tested.

The accumulator pressure and level is continuously monitored during station operation.

The accumulators and the injection piping up to the final isolation valve are maintained full of borated water while the station is in operation. The boron concentration in the line may be diluted due to check valve back-leakage from the RCS. The accumulators are refilled with borated water as required by using the positive-displacement hydrotest pump. The boron concentration in the accumulators is sampled periodically.

The length of pipe between the valve pit and the pump suction for the safety injection system is ≈3 feet. This run of pipe is embedded in concrete. The length of pipe between the valve pit and the pump suction for the outside recirculation spray system is ≈10 ft. 6 in. The pipe employed is 12-inch, Schedule 40S, fabricated of ASTM A358, Type 304 material, in accordance with Code for Pressure Piping USAS B31.1.0, 1955 edition, plus Code Cases N-1 and N-7.

Under normal plant operating conditions, the recirculation spray piping in the valve pit is maintained dry and the low-head safety injection piping in the valve pit is subjected to RWST head pressure. Heavy wall piping has been used, and welds have been radiographed during construction.

The methods of leak detection for the piping are as follows:

Large leaks in the suction piping, which is located in the valve pit, will be detected by the following devices: (1) liquid level measuring instrumentation, (2) exhaust ventilation radiation monitor, (3) outside recirculation spray pump discharge pressure instrumentation, (4) low head safety injection flow rate instrumentation, (5) outside recirculation spray pump motor amperage instrumentation, and (6) low head safety injection pump motor amperage instrumentation. Upon detection of a potential leak from any of these sources, control room personnel will identify the affected flow path by observation of the system parameters.

With the leak path identified, the operator in the control room has the capability to remote manually isolate the leaking subsystem, leaving one recirculation loop and one safety injection loop operable, if required.

The volume of water required in the valve pit to actuate the high water level alarm in the control room is 400 gallons. A small leak rate, which may be defined as 10 percent of the total flow in the piping, will cause the alarm to sound in less than 90 seconds since the total flow in the piping is 3000 to 3500 gpm.

In the case of small leaks, specific detection of a leak is not possible; however, when the operation of these systems is initiated, the same signal diverts the ventilation air from the structure enclosing the piping outside the containment through charcoal filters. Thus, no escape of unfiltered gases or liquid to the outside environment can occur.

6.2.4.1.5 Gas Accumulation in ECCS Piping

The HHSI suction line vent valves have been installed to allow venting during operations or during non-operating vent and fill procedures to minimize the possibility of gas intrusion into the HHSI pumps. Similarly, the LHSI discharge line vent valves are used to reduce the potential for pressure surges, which may challenge the LHSI discharge line thermal relief valves upon LHSI pump starts. The LHSI discharge piping to the HHSI suction (piggy-back line) vent valves are used to minimize both the possibility of gas intrusion into the HHSI pumps and the potential for pressure surges in the LHSI discharge lines (Reference 10).

Following equipment maintenance or refueling outages where an ECCS subsystem is opened, some entrained non-condensable gases remain. Each ECCS subsystem is filled and vented in a manner deemed appropriate for removal of gases. Each ECCS subsystem is demonstrated operable prior to return to service by verifying that the ECCS piping is sufficiently full of water through Ultrasonic Testing (UT), venting or other means (Reference 20).

Accessible portions of ECCS subsystems that are susceptible to gas sources are demonstrated operable periodically by verifying that the ECCS piping outside of containment is sufficiently full of water through Ultrasonic Testing (UT), venting or other means. Maintaining the piping in the ECCS sufficiently full of water as determined by engineering analysis ensures that the system will perform properly when required to inject into the RCS. Specifically, this will prevent gas-water hammer, degraded system performance, and cavitation and gas binding of the ECCS pumps due to gas accumulation in the piping. It will also reduce the potential for pumping of non-condensable gases (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The ECCS discharge is inaccessible during reactor operations due to subatmospheric conditions, safety concerns and radiological concerns. The ECCS discharge piping inside containment is filled and vented upon system return to service (Reference 20).

6.2.4.2 **Inspections**

Quality standards of safety injection system components are presented in Table 6.2-3.

All components of the safety injection system are inspected periodically to demonstrate system readiness.

The pressure-containing components are inspected for leaks from pump seals, valve packing, flanged joints, and safety valves during system testing.

6.2 REFERENCES

1. A. C. Griess and A. L. Bacarella, "Design Considerations of Reactor Containment Spray Systems - Part III," *The Corrosion of Material in Spray Solutions*, ORNL-TM-2412, Part IV.
2. Knudsen, J. G. and Hilliard, R. K., 1969. *Fission Product Transport by Natural Processes in Containment Vessels.* Battelle - Northwest, Richland, Washington, BNWL- 943.
3. Hilliard, R. K., et al., 1970. *Removal of Iodine and Particulates from Containment Atmosphere by Sprays.* Battelle - Northwest, Richland, Washington, BNWL-1244.
4. Letter from Virginia Electric and Power Company to U. S. Atomic Energy Commission, Docket Nos. 50-280 and 50-281 dated July 16, 1973, Serial No. 03873.
5. Letter from W. L. Stewart to Harold R. Denton (NRC), *Amendment to Operating Licenses DPR-32 and DPR-37, Surry Power Station Units 1 and 2, Proposed Technical Specifications Change,* Serial No. 521, September 13, 1983.
6. Letter from W. L. Stewart to Harold R. Denton (NRC), *Supplement to An Amendment to Operating Licenses DPR-32 and DPR-37 - Proposed Reduction in Boron Concentrations - Surry Power Station Units 1 and 2,* Serial No. 521B, November 30, 1983.
7. *Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 95 to Facility Operating License No. DPR-32 and Amendment No. 94 to Facility Operating License No. DPR-37 - Virginia Electric and Power Company Surry Power Station, Unit Nos. 1 and 2 - Docket Nos. 50-280 and 50-281,* February 24, 1984. (NRC SER for BIT boron concentration reduction)
8. NRC Generic Letter 95-07, *Pressure Locking and Thermal Binding of Safety Related Power Operated Gate Valves,* dated August 17, 1995.
9. Letter from Virginia Electric and Power Company to USNRC dated February 7, 1996 (Serial No. 95-566A), *Generic Letter 95-07 Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves, Surry and North Anna Power Stations.*
10. Information Notice 88-23, *Potential for Gas Binding of High Pressure Safety Injection Pumps During a Loss-of-Coolant Accident.*
11. Letter from L.N. Hartz to USNRC, *Virginia Electric and Power Company, Dominion Nuclear Connecticut, Inc., Surry Power Station Units 1 and 2, North Anna Power Station Units 1 and 2, Millstone Power Station Units 2 and 3, Application for Technical Specification Improvement to Eliminate Requirements for Hydrogen Recombiners and Hydrogen Monitors Using the Consolidated Line Item Improvement Process,* Serial No. 04-386, dated September 8, 2004.
12. Letter from USNRC to D.A. Christian, *Surry Power Station, Units 1 and 2 - Issuance of Amendments on Elimination of Requirements for Hydrogen Monitors Using the Consolidated Line Item Improvement Process (TAC Nos. MC4393 and MC4394),* dated March 22, 2005.
13. Topical Report DOM-NAF-3, Rev. 0.0-P-A, *GOTHIC Methodology For Analyzing the Response to Postulated Pipe Ruptures Inside Containment,* September 2006.

14. NRC Generic Letter GL 2004-02, *Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors*, dated September 13, 2004.

15. Letter from Dominion Resources Inc. to the NRC, dated September 1, 2005, Serial No. 05-212, Response to NRC Generic Letter 2004-02.

16. Nuclear Energy Institute (NEI) Document NEI 04-07, *Pressurized Water Reactor Sump Performance Evaluation Methodology*, dated December 2004.

17. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to NRC Generic Letter 2004-02, *Nuclear Energy Institute Guidance Report Pressurized Water Reactor Sump Performance Evaluation Methodology*.

18. Westinghouse Document WCAP-16406-P, Revision 1, *Downstream Wear Evaluation Methodology for Containment Sump Screens in Pressurized Water Reactors*.

19. Westinghouse Document WCAP-16793-NP, Revision 0, *Evaluation of Long-Term Cooling Considering Particulate, Fibrous and Chemical Debris in the Recirculating Fluid*.

20. Letter from Dominion Resources Inc. to NRC, dated October 14, 2008, Serial No. 08-0013B, "*Nine Month Response to NRC Generic Letter 2008-1*."

6.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-089A	Flow/Valve Operating Numbers Diagram: Safety Injection System, Unit 1
	11548-FM-089A	Flow/Valve Operating Numbers Diagram: Safety Injection System, Unit 2
2.	11448-FM-089B	Flow/Valve Operating Numbers Diagram: Safety Injection System, Unit 1
	11548-FM-089B	Flow/Valve Operating Numbers Diagram: Safety Injection System, Unit 2

Table 6.2-1
CODE REQUIREMENTS FOR THE SAFETY INJECTION SYSTEM

Component	Code
Accumulators	ASME Section III, Class C
Valves	USAS B16.5
Piping	USAS B31.1

Table 6.2-2
SAFETY INJECTION CONTROL BOARD INDICATION

I. VALVES

System	Actuation Position on Injection	Valve No.	Description
SIS	Open	MOV-867 C, D	HHSI to RCS cold leg isolation
SIS	Normally closed	MOV-842	HHSI to RCS cold leg isolation - alternate header
SIS [c]	Normally open	MOV-865 A, B, C	SI accumulator isolation valves
SIS [a]	Shut	MOV-890 A, B	Low-head SI to RCS hot leg isolation
SIS [a]	Open	MOV-890 C	Low-head SI to RCS cold leg isolation
SIS [c]	Normally open	MOV-862 A, B	RWST to low-head SI pump isolation
SIS	Normally closed	MOV-860 A, B	Containment sump to low-head SI pump isolation valve
SIS	Normally closed	MOV-863 A, B	Low-head to high-head SI pump isolation
SIS [c]	Normally open	MOV-885 A, B, C, D	Low-head pump miniflow isolation
SIS [a, c]	Shut	MOV-869 A, B	High-head SI to RCS hot-leg isolation
SIS/CVCS	Closed	MOV-289 A, B	Normal charging isolation
SIS	Open [b]/Closed	TV-102 A, B, TV-202 A, B	RWST cross tie isolation

a. During normal operation, these valves are placed in the position shown and power is removed from the motor operator.
b. Associated trip valves open only on a steam line break (SLB) signal, otherwise trip valves remain closed.
c. These valves actuate an alarm in the control room when not in the normal position.

Notes: Individual position lights are included to indicate the full-open or full-closed position of each valve. These lights function for MOVs only when the valve motor operator power circuit is energized.

SIS = safety injection system
CVCS = chemical and volume control system
RWST = refueling water storage tank
VCT = volume control tank

Table 6.2-2 (CONTINUED)
SAFETY INJECTION CONTROL BOARD INDICATION

I. VALVES (continued)

System	Actuation Position on Injection	Valve No.	Description
SIS/CVCS	Normally open	MOV-275 A, B, C	Individual high-head SI/charging pump miniflow isolation
SIS/CVCS	Normally open	MOV-373	Combined high-head SI/charging pump miniflow isolation
CVCS	Closed	MOV-LCV-115 C, E	VCT to charging pump isolation
CVCS	Open	MOV-LCV-115 B, D	RWST to high-head SI pump isolation
CVCS	Normally open	MOV-267A	RWST to #1 high-head SI pump isolation
		MOV-267B	Low-head to #1 high-head SI pump isolation
CVCS	Normally open	MOV-269A	RWST to #2 high-head SI pump isolation
		MOV-269B	Low-head to #2 high-head SI pump isolation
CVCS	Normally open	MOV-270A	RWST to #3 high-head SI pump isolation
		MOV-270B	Low-head to #3 high-head SI pump isolation
CVCS	Normally open	MOV-286 A, B, C	Individual high-head SI/charging pump to normal charging isolation
CVCS	Normally open	MOV-287 A, B, C	Individual high-head SI/charging pump to SI line isolation

Table 6.2-2 (CONTINUED)
SAFETY INJECTION CONTROL BOARD INDICATION

II. INSTRUMENTS

System	Instrument No.	Description
SIS	FI-946	Low-head SI pump B flow
SIS	FI-945	Low-head SI pump A flow
SIS	FI-943	High-head SI normal header flow
SIS	FI-943A	Redundant high-head SI normal header flow
SIS	FI-940	High-head SI alternate header flow
SIS	FI-940A	Redundant high-head SI alternate header flow
SIS	FI-960	Loop 2 hot-leg high-head SI flow
SIS	FI-961	Loop 1 cold-leg high-head SI flow
SIS	FI-962	Loop 2 cold-leg high-head SI flow
SIS	FI-963	Loop 3 cold-leg high-head SI flow
SIS	FI-932	Loop 3 hot-leg high-head SI flow
SIS	FI-933	Loop 1 hot-leg high-head SI flow

III. PUMPS

System	Pump
SIS	Low-head safety injection
SIS/CVCS	High-head Safety injection/charging

Table 6.2-3
QUALITY STANDARDS OF SAFETY INJECTION SYSTEM COMPONENTS

I. Pumps
   A. Tests and Inspections
      1. Performance test
      2. Dye penetrant of pressure-retaining parts
      3. Hydrostatic test
      4. Special Manufacturing Process Control
      5. Weld, NDT, and inspection procedures review
      6. Surveillance of supplier's quality control system and product
II. Accumulators
   A. Tests and Inspections
      1. Hydrostatic test
      2. Radiography of longitudinal and girth welds
      3. Dye penetrant/magnetic particle of weld
      4. Special Manufacturing Process Control
      5. Weld, fabrication, NDT, and inspection procedure review
      6. Surveillance of supplier's quality control and product
III. Valves
   A. Tests and Inspections
      1. 200 psig and 200°F or below (stainless steel valves only)
         a. Dye penetrant test
         b. Hydrostatic test
         c. Seat leakage test
      2. Above 200 psig and 200°F
         a. Forged valves
            1) Ultrasonic test of billet prior to forging
            2) Dye penetrant check 100% of accessible areas after forging
            3) Hydrostatic test
            4) Seat leakage test

---

a. For valves with radioactive service only.

b. These one-time tests were performed prior to being placed in-service.

Table 6.2-3 (CONTINUED)
QUALITY STANDARDS OF SAFETY INJECTION SYSTEM COMPONENTS

III. Valves (continued)
- b. Cast valves
  - 1) Radiograph 100% [a]
  - 2) Dye penetrant check all accessible areas [a]
  - 3) Hydrostatic test
  - 4) Seat leakage test
- 3. Performance tests required for
  - a. Motor-operated valves
  - b. Auxiliary relief valves
  - c. Air-operated valves
- 4. Auxiliary relief valves (these valves are not included in the above categories)
  - a. 100% dye penetrant check of nozzles and disks
  - b. 100% dye penetrant check of bodies [a]
  - c. Hydrotest bodies, nozzles, and disks
  - d. Seat leakage test
  - e. Operational tests
- B. Special Manufacturing Process Control
  - 1. Weld, NDT, performance testing, assembly, and inspection procedure review
  - 2. Surveillance of supplier's quality control and product
  - 3. Special weld process procedure qualification (e.g., hard facing)

IV. Piping
- A. Tests and Inspections
  - 1. 100% radiographic inspection and penetrant examination for stainless steel welds in radioactive service.
  - 2. 100% radiographic inspection for 20% of butt welds and penetrant examination for all fillet welds for stainless steel welds in non-radioactive service.
- B. Special Manufacturing Process Control
  - 1. Surveillance of supplier's quality control and product

V. Strainer Assembly
- A. Tests and Inspections
  - 1. Liquid penetration and visual inspection in accordance with ASME Section IX

---

a. For valves with radioactive service only.

b. These one-time tests were performed prior to being placed in-service.

Table 6.2-3 (CONTINUED)
QUALITY STANDARDS OF SAFETY INJECTION SYSTEM COMPONENTS

V. Strainer Assembly (continued)

B. Performance Tests [b]

1. Hydraulic test to determine head loss due to debris and chemical effects
2. Strainer fiber bypass testing

C. Special Manufacturing Process Control

1. Surveillance of supplier's quality control and product

---

a. For valves with radioactive service only.

b. These one-time tests were performed prior to being placed in-service.

Table 6.2-4
ACCUMULATOR DESIGN PARAMETERS

Number	3	
Type	Stainless steel lined/carbon steel	
Design pressure	700	psig
Design temperature	300°F	
Operating temperature	80-105°F	
Normal operating pressure	600-665	psig
Total volume	1450	ft^3
Minimum water volume at operating conditions	975	ft^3
Minimum boron concentration (as boric acid)	2250	ppm
Relief valve setpoint [a]	700 psig	

a. The relief valves have soft seats and are designed and tested to ensure zero leakage at the normal operating pressure.

Table 6.2-5
PUMP PARAMETERS[a]

Safety Injection Charging Pumps	
Number of pumps (per unit)	3
Design pressure, discharge	2735 psig
Design pressure, suction	150 psig
Design temperature	250 °F
Design flow rate	150 gpm
Maximum continuous runout flow rate	550 gpm[b]
Design head	5800 ft
Type	Horizontal centrifugal
Low-Head Safety Injection Pumps	
Number of pumps (per unit)	2
Type	Vertical centrifugal
Design pressure, discharge	150 psig
Design temperature	230°F
Design flow	3000 gpm
Design head	225 ft
Maximum flow rate	4000 gpm

a. Design information only. Various HHSI and LHSI system flow requirements are given in the appropriate system analyses.
b. Maximum continuous runout limit for 1-CH-P-1B is 575 gpm.

Table 6.2-6
TOTAL POTENTIAL EXTERNAL RECIRCULATION LOOP LEAKAGE TO ATMOSPHERE FROM THE SAFETY INJECTION SYSTEM

Items	Type of Leakage Control and Unit Leakage Rate Used in the Analysis [a]
Low-head safety injection pumps	Mechanical seal with leakoff - four drops per minute
Safety injection charging pumps	Mechanical seal with leakoff - four drops per minute
Flanges	Gasket - adjusted to zero leakage following any test - 40 drops per minute, per flange used in analysis
Pump	
Valves, bonnet to body (larger than 2 inches)	
Valves - stem leakoffs	Double packing with leakoff - 4 cm^3/hr/in stem diameter
Valves - stem leakoffs capped	Leakoff - 4 cm^3/hr/in stem diameter
Miscellaneous valves	Flanged body packed stem - four drops per minute
	Total Potential Leakage 3836 cc/hr

a. Unit leakage rates are original design criteria. The actual allowable leakage for each leakage control component may exceed the original leakage rate indicated as long as the total external recirculation loop leakage does not exceed 12,000 cc/hr as required by Section 14.5.5.3.

Table 6.2-7
CONSTRUCTION MATERIAL EXPOSURE TO CONTAINMENT SPRAY

Material	Corrosion Rate[a]
Carbon steel [b]	0.0
Stainless steel	0.0
Concrete [b]	0.0
Mineral wool	0.0
Calcium silicate and Unibestos	0.0
Aluminum	12.0 $mg/dm^2/hr$ [c]
Zinc (paint and galvanizing on steel)	0.04 $mg/dm^2/hr$ [c]
Copper	0.0
90-10 copper nickel	0.0
Polyethylene and neoprene	0.0

The maximum total duration of use for the containment spray system is approximately 60 minutes.

---

a. Less than 1 mil/yr considered to be zero corrosion rate.

b. Painted with Corlar Epoxy Chemical Resistant Enamel, which is a polyamide catalyzed epoxy resin paint.

c. Corrosion rate at 140°F, maximum exposure temperature after 1 hour. Aluminum has corrosion rate of less than 800 $mg/dm^2/hr$ at peak temperature.

Table 6.2-8
SINGLE-ACTIVE-FAILURE ANALYSIS OF SAFETY INJECTION SYSTEM

Component	Malfunction	Comments
A. Accumulator (injection phase)	Delivers to broken loop	Totally passive system with one accumulator per loop. Evaluation based on two accumulators delivering to the core and one spilling from ruptured loop.
B. Pump (injection phase)		
1. Safety injection charging	Fails to start	Three provided. Evaluation based on operation of one.
2. Low-head safety injection	Fails to start	Two provided. Evaluation based on operation of one.
C. Automatically operated valves (open on safety injection signal) (injection phase)		
1. Isolation valves at discharge of high-head safety injection pumps (cold-leg injection)	Fails to open	One of two parallel valves is required to open.
2. Low-head safety injection pump discharge isolation valves (cold-leg injection)	Fails to open	One line from each pump leading to common discharge header. Isolation valve in this line locked open.
3. Accumulator stop valves	Fails to open	One valve per accumulator, normally open, or opened if initially closed. Analysis assumes all three accumulator stop valves are open.
4. Refueling water storage tank to charging pump return valves	Fails to open	Two in parallel; one out of two is assumed to open.
D. Valves automatically closed on safety injection signal		
1. Charging line injection	Fails to close	Two valves in series are provided wherever closure is required.
2. Volume control tank discharge	Falls to close	Two valves in series are provided wherever closure is required.
E. Valves operated for recirculation		
1. Containment sump	Fails to open	Two lines in parallel; one valve either line is required to open.
2. High-head safety injection pump suction valve from low-head safety injection pump discharge	Fails to open	One recirculation line from each low-head pump. One motor-operated valve in each line, one of which must open.

Table 6.2-8 (CONTINUED)
SINGLE-ACTIVE-FAILURE ANALYSIS OF SAFETY INJECTION SYSTEM

Component	Malfunction	Comments
3. Isolation valve at suction header of low-head safety injection pump from refueling water storage tank	Fails to close	Motor valve and check valve in series. Motor valve required to close backed up by check valve.
4. Isolation valves suction to high-head safety injection pumps	Fails to close	Two motor valves in parallel, backed up by check valve and administratively controlled, normally open manual gate valve.
5. Isolated valves on the low-head safety injection system minimum flow or a test line returning to the refueling water storage tank	Fails to close	Two motor-operated valves in each minimum flow line in series with a check valve in each line.
6. Discharge valve on high-head safety injection pump	Fails to close	All are normally open. Failure of one to close does not prevent a separate recirculation path from the high-head safety injection pump discharge.
7. Suction valve on high-head safety injection pump	Fails to close	All are normally open. Failure of one to close does not prevent a separate recirculation path from the containment sump to the suction of the high-head safety injection pumps.

Table 6.2-9
SHARED FUNCTIONS EVALUATION

Component	Normal Operating Function	Normal Operating Arrangement	Accident Function	Accident Arrangement
Refueling water storage tank	Storage tank for refueling	Lined up to suction of high-head safety injection charging, low-head safety injection, and containment spray pumps	Source of borated water for core and containment cooling	Line up to suction of high-head safety injection charging, low-head safety injection, and containment spray pumps
Accumulators (3)	None	Lined up to discharge to cold legs of reactor coolant piping	Fast supply of borated water to core	Lined up to discharge to cold legs of reactor coolant piping
Safety injection charging pumps (3)	Charging	Take suction from volume control tank and discharge to normal charging connections	Supply borated water to core	Lined up to take suction from refueling water storage tank and discharge to hot and cold legs of reactor coolant piping
Low-head safety injection pumps (2)	None	Lined up to take suction from refueling water storage tank and discharge to reactor coolant piping	Supply borated water to core	Line up to take suction from refueling water storage tank and discharge to reactor coolant piping

Table 6.2-10
ACCUMULATOR INLEAKAGE [a]

Observed Leak Rate (cc/hr)	Time Period Between Level Adjustments (hours)
543	1703
272	3399
30.3	30,513

a. A maximum of approximately 30 ft^3, added to the initial amount, can be accepted in each accumulator before an alarm is sounded. The Technical Specifications establish the minimum and maximum water volume in each SI accumulator.

Table 6.2-11
ANALYSIS PARAMETERS AVAILABLE NPSH ANALYSIS LHSI PUMPS[a]

Initial Containment Pressure	11.82	psia
Initial Containment Temperature	125°F	
Service Water Temperature	70°F	
Refueling Water Storage Tank Temperature	45°F	

a. Instrumentation uncertainties for these parameters have been included in the safety analysis.

Table 6.2-12
NPSH REQUIREMENTS SAFETY INJECTION PUMPS

Low-Head Safety Injection Pumps		
	Injection	Recirculation
Required	16.1 ft	13.82 ft
Minimum Available	67.86 ft	15.7 ft
Flow Per pump	3371 gpm	3330 gpm
High-Head Safety Injection Pumps		
	Injection	Recirculation
Required	24 ft	Bounded by
Minimum Available	53.47 ft	Injection
Flow Per pump	590 gpm	Mode

Table 6.2-13
NPSH REQUIREMENTS RECIRCULATION SPRAY PUMPS[a]

Inside Recirculation Spray Pumps	
Required[c]	11.02 ft
Available	15.22 ft
Flow	3650 gpm
Outside Recirculation Spray Pumps	
Required[c]	9.73 ft
Available[b]	13.26 ft
Flow	3300 gpm

a. The head loss across the strainer is within the available NPSH margin.
b. This available NPSH assumes that the corresponding outside recirculation spray pump receives bleed flow from the CS System that varies from 294 gpm at 26.8 psid to 325.6 gpm at -8.6 psid.
c. Pump Required NPSH varies with the pumped fluid temperature. The information presented reflects the NPSH Required at the transient point of minimum margin between NPSH Available and NPSH Required.

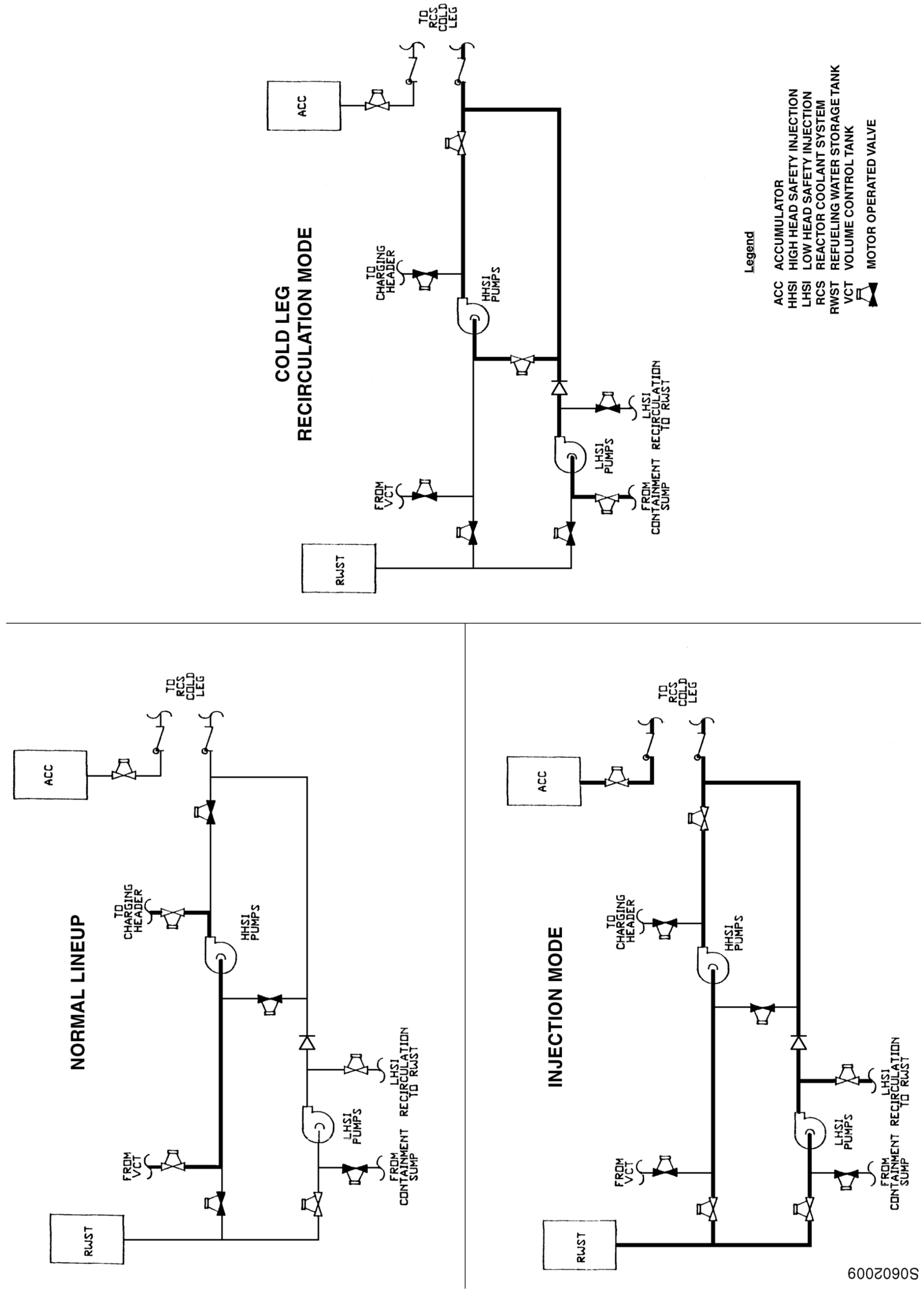


Figure 6.2-1
SAFETY INJECTION SYSTEM

Figure 6.2-2
PROTECTION PROVIDED BY VARIOUS COMBINATIONS OF SAFEGUARDS COMPONENTS

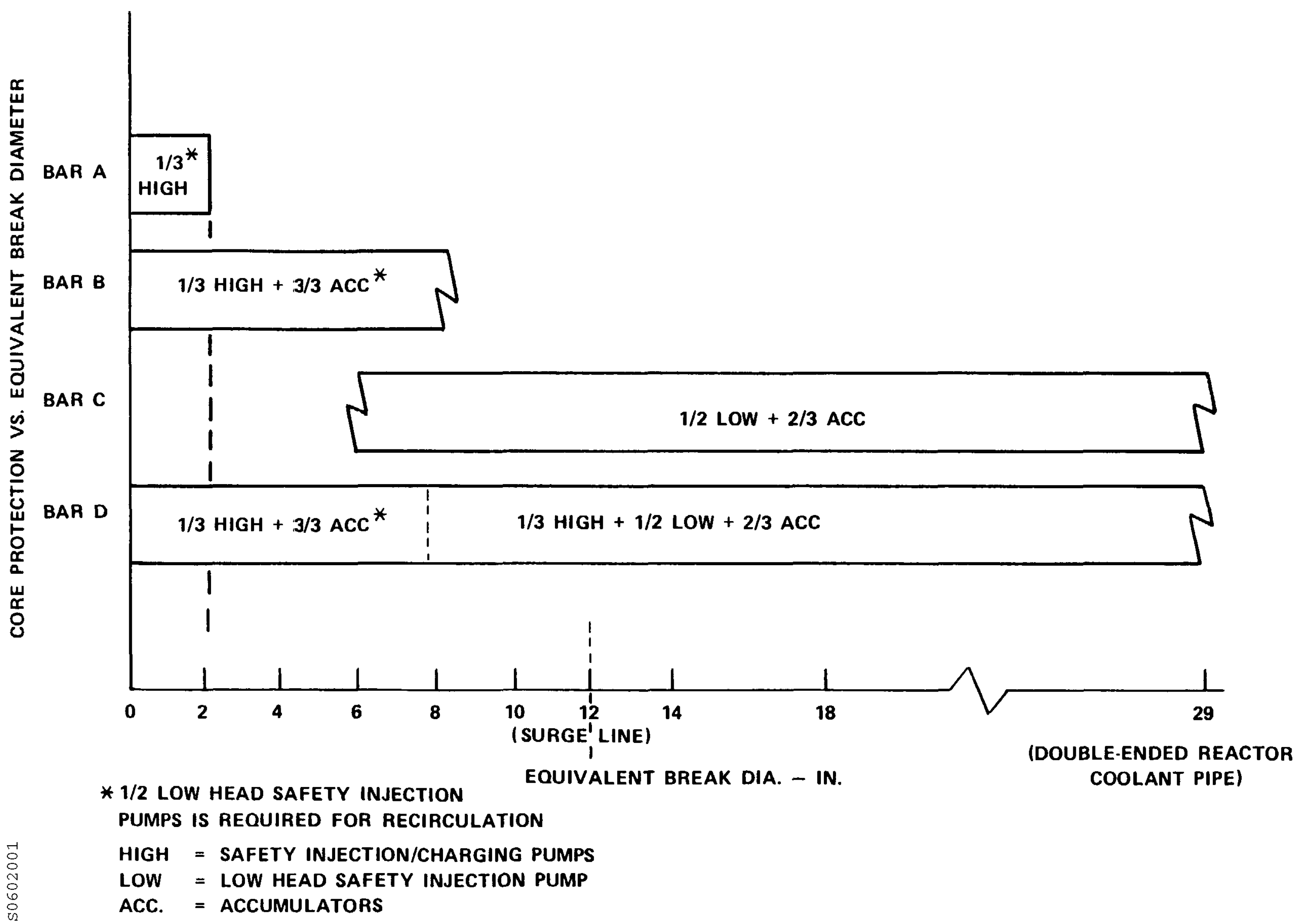


Figure 6.2-3
AVAILABLE NPSH LHSI PUMP NPSH AVAILABLE ANALYSIS

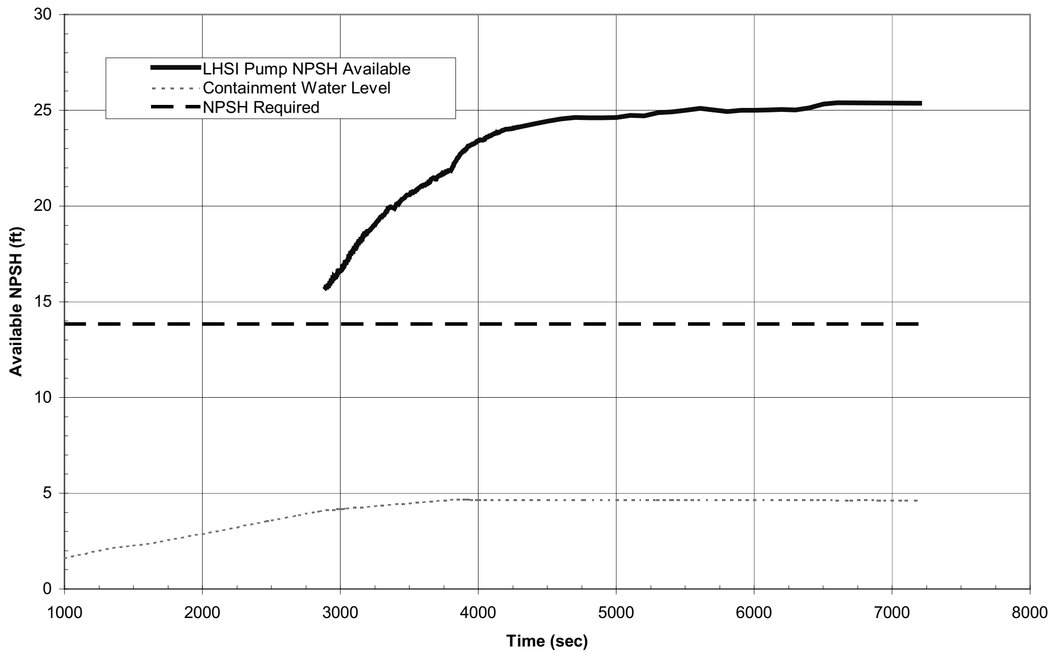


Figure 6.2-4
CONTAINMENT PRESSURE LHSI PUMP NPSH AVAILABLE ANALYSIS

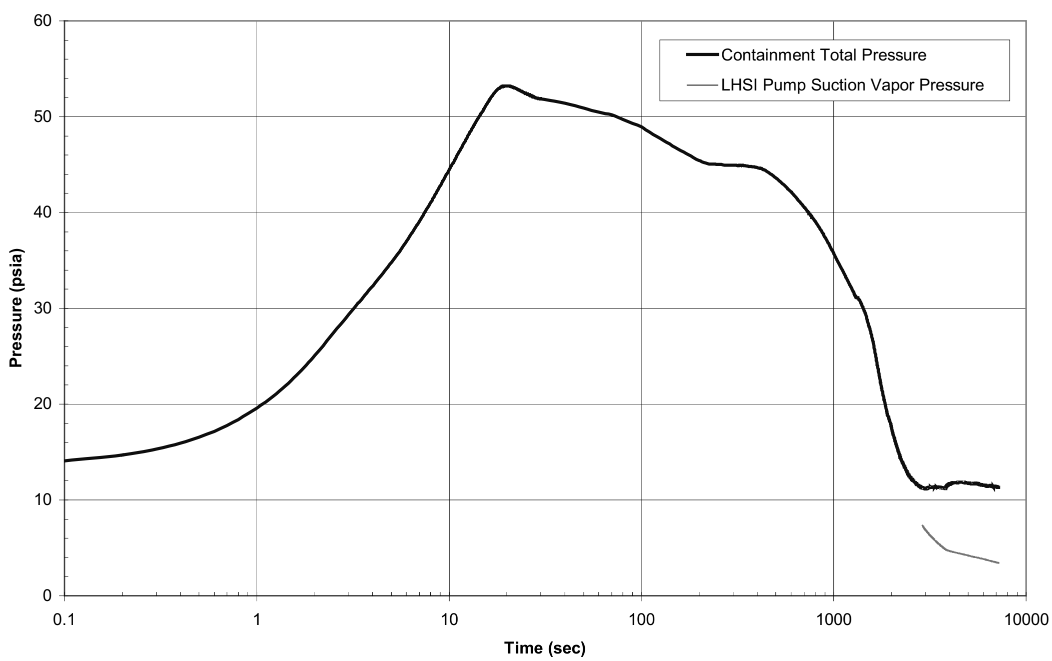


Figure 6.2-5
CONTAINMENT TEMPERATURES LHSI PUMP NPSH AVAILABLE ANALYSIS

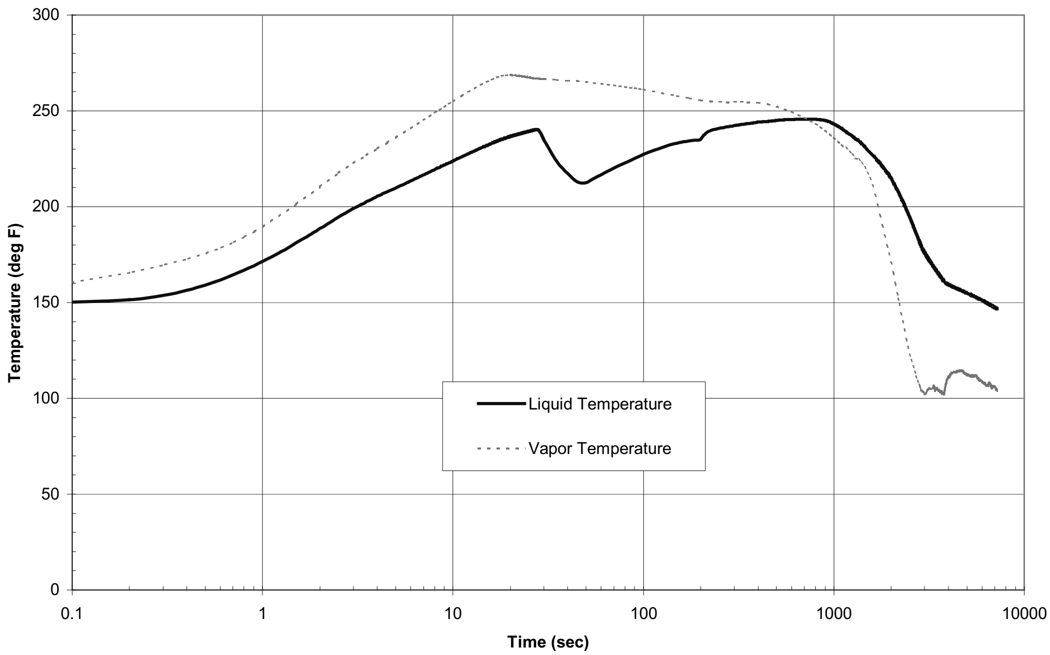
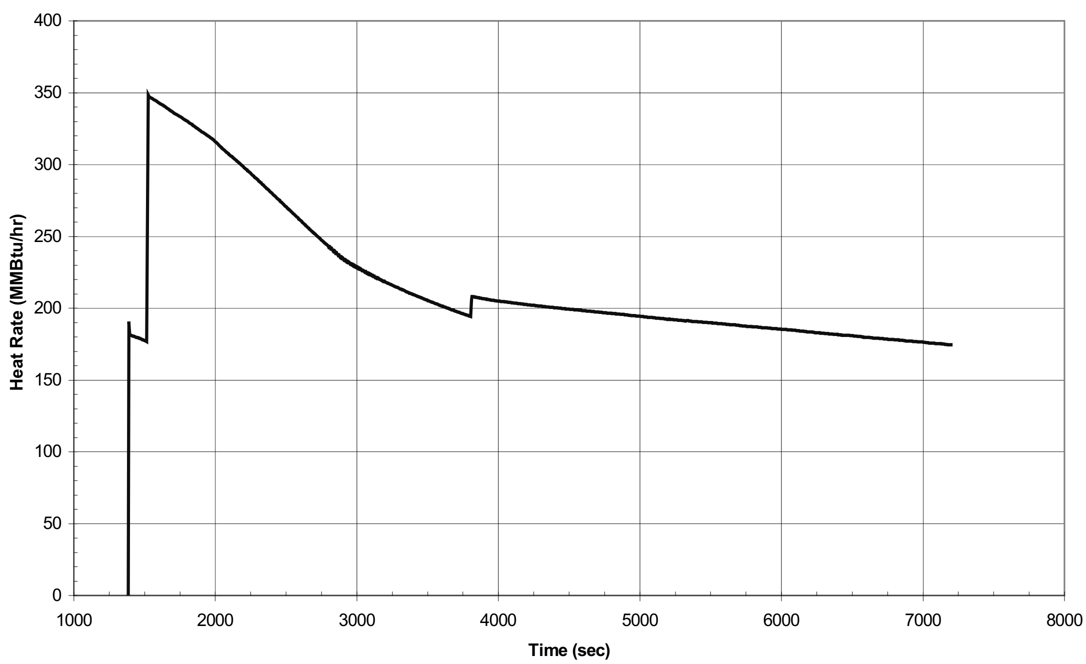


Figure 6.2-6
TOTAL RSHX HEAT RATE LHSI PUMP NPSH AVAILABLE ANALYSIS



6.3 CONSEQUENCE-LIMITING SAFEGUARDS

6.3.1 Spray System

6.3.1.1 Design Bases

The spray system consists of the containment spray subsystem and the recirculation spray subsystem, which are designed to provide the necessary cooling and depressurization of the containment after any LOCA. Spray system component data are given in Table 6.3-1.

Safety related components, piping, valves, and supports in the spray system are Seismic Category I.

The subsystems, operating together, cool and depressurize the containment to subatmospheric pressure following the design-basis accident.

The recirculation subsystem is, in addition, capable of maintaining the subatmospheric pressure in the containment for an extended period following the design-basis accident.

The removal of radioactive iodine from the containment atmosphere after a design-basis accident is accomplished through the dissolution of sodium tetraborate decahydrate into the containment sump water which is used by the recirculation spray subsystem (Section 14.5.4).

The spray system is designed to depressurize the containment to subatmospheric pressure with any one of the two containment spray pumps operating and only two of the four recirculation spray pumps operating.

6.3.1.2 Spray System Components

The spray system is designed, fabricated, inspected, and installed to meet the requirements of the General Design Criteria, as discussed in Section 1.4. The spray subsystems and their components are considered to be essential to accident prevention and/or the mitigation of accident consequences that could affect the public health and safety.

6.3.1.2.1 Pumps and Valves

The spray pumps and valves are fabricated, welded, and inspected according to the requirements of the applicable portions of the ASME Code, Sections III, VIII and IX. Materials of construction are stainless steel or equivalent corrosion-resistant materials.

Valve packing and pump seals are selected to minimize or eliminate leakage where necessary. Motor-operated valve operators are selected because their proven superior reliability in past applications ensures reliable valve operation under incident conditions.

The Teflon sleeve and packing of the outside recirculation spray system suction valves have been changed to XOMOX 7. This change reflects the review performed in accordance with NUREG-0578, Section 2.1.6.b. In this review it was found that the valves would be located in a high-radiation area as a result of a LOCA. The Teflon material is satisfactory to only 1×10^4 rads, whereas the XOMOX 7 material is satisfactory to 8×10^6 rads. The expected 60-year normal plus postaccident integrated radiation dose in this area is conservatively estimated not to exceed 8×10^6 rads.

The containment spray system piping and equipment are fabricated of ASTM A358, Type 304 stainless steel, or equivalent, which has a corrosion rate of less than 0.0001 in/yr at the 4.25 to 4.75 pH.

The recirculation spray system piping and equipment are also fabricated of Type 304 or Type 316L stainless steel, or equivalent, except for the Recirculation Spray Heat Exchanger (RSHX) tubing which is titanium, and the spray nozzles which are brass. System operating conditions are 200° to 130°F temperature and 7.0 to 9.0 pH (during the long-term postaccident period.

Per NUREG-0800 (Reference 11), stress corrosion cracking of austenitic stainless steel is inhibited in borated solutions in the hypothetical environment after the design-basis accident, when the pH is 7.0 or greater.

The systems operate at a relatively low pressure of approximately 100 psi gauge and are not highly stressed during operation, so that the inducement toward cracking is reduced.

The potential for caustic stress corrosion cracking in the containment spray system and recirculation spray system is virtually nonexistent because of the following:

1. The short duration of containment spray system operation
2. The recirculation spray solution pH is above 7.0 during the long-term postaccident period

6.3.1.2.2 Motors

Electrical insulation for motors located outside containment is in accordance with ANSI, IEEE, and NEMA standards, and is tested as required by these standards. Temperature rise design is such that normal long life is achieved even under accident loading conditions.

Winding insulation has been developed that operates at temperatures well in excess of those calculated to occur under design-basis accident conditions. This type of insulation is used in motors located inside containment.

The containment motors have been selected to ensure operation during LOCA conditions. Motor electrical insulation is in accordance with ANSI, IEEE, and NEMA standards. The motors are tested as required by these standards. Bearings are antifriction type. Bearing loading and high-temperature tests have been performed, and the expected bearing life equals, or exceeds, that specified by the Anti Friction Bearing Manufacturers Association (AFBMA).

6.3.1.2.3 Piping

Piping fabrication, installation, and testing are in accordance with the Specification for Power Plant Piping, ANSI B31.1, with supplemental requirements and inspections as necessary for use in nuclear applications. Pipe routing and supports are such that missiles generated from postulated events or the effects of LOCAs do not impair the operation of spray systems.

6.3.1.2.4 Heat Exchangers and Vessels

Heat exchangers and vessels are designed to ASME Code, Section VIII, Division 1, and have been radiographed in accordance with ASME Code Section VIII to ensure their structural integrity. Heat exchangers and vessels are of welded construction to preclude leakage.

6.3.1.2.5 Strainer Assembly

One strainer assembly is provided for both the IRS and ORS System pumps. The RS strainer assembly consists of two trains which traverse along the containment wall on both sides of the sump. The strainer assembly consists of a number of modules which channel water to the pump suction. Each suction opening is connected to the modules which form the strainer header. Modules are connected to each other by flexible metal seals. Seal closure frames with Metex seals are installed over existing flexible metal seals. The seal closure frame assemblies form the seal between adjacent strainer modules. Each module contains a number of fins which filter the water flowing into the modules. Each fin contains a number of holes 0.0625-inch (nominal) in diameter. Perforations on the strainer fins prevent particles larger than 0.06875-inch (0.0625-inch plus 10 percent) from entering the RS System. The total perforation area is large enough to allow sufficient flow to the suction of RS pumps to meet NPSH requirements.

Since the installation of the strainer assembly, inspections have identified gaps in the assembly larger than the allowable 0.0625-inch gap size. Particles larger than 0.06875 inches were evaluated in response to gaps identified in the strainer assembly. As part of the evaluation, it was assumed that 1% of the total generated particles between 0.06875 inches (0.0625 inches plus 10 percent) and 0.1375 inches (0.125 inches plus 10 percent) would pass through the strainer. It was determined that these particles would not impact the performance of downstream components.

For the ORS pumps, the strainer header is connected to each suction opening by a flanged transition adapter. The OD of the strainer header is machine cut and slip-fitted in to the new adapter ensuring that the gaps between the piping and the adapter do not exceed 0.0625 inches.

For the IRS pumps, the strainer header is connected to the pump well by installing a new casing.

The strainer assembly is designed and fabricated to the requirements of ASME Section III, Subsection NF, Class 3. All material used in the construction of the strainer assembly is austenitic stainless steel.

The strainer assembly is capable of withstanding the full debris loading in conjunction with all design basis conditions without collapse or structural damage.

The suction lines between the containment sump and the ORS pumps are cross connected. This design feature was originally provided to ensure a supply of water to each pump in the event that the suction of either pump become clogged. The current common header strainers that protect the pump suction lines are designed to withstand the full debris load that could be generated by a LOCA.

The design data of the spray system components are given in Table 6.3-1.

6.3.1.3 **Description**

6.3.1.3.1 Containment Spray System

The containment spray system consists of two completely separate trains of spray rings located in the containment dome and one common spray ring located outside the crane wall. Each train is rated at 100% capacity. The recirculation spray system is composed of two trains, each consisting of an inside recirculation spray subsystem and an outside recirculation spray subsystem. Each subsystem is approximately 50% capacity, and consists of one recirculation spray pump, one recirculation spray heat exchanger (RSHX), and one 180° coverage spray header with nozzles.

An additional ring header common to both containment spray trains is installed at Elevation 95 ft. 6 in. outside the crane wall. Check valves are installed in each branch connection from the riser to the common header to limit fill time, should one containment spray pump train fail to start.

The containment spray subsystem is shown in Figure 6.3-1, and the recirculation spray subsystem is shown in Figure 6.3-2. Elevations of all piping and components of these subsystems are shown in Figure 6.3-4.

Each of the containment spray headers draws water independently from the refueling water storage tank. The refueling water storage tank is a vertical cylinder with a flat bottom and a dome top, and is secured to a reinforced-concrete foundation. The refueling water storage tank is fabricated of ASTM A240, Type 304L stainless steel, in accordance with API STD-650. The requirements for welding, welding procedures, welder qualification, weld point efficiency, and weld inspection are in accordance with Section IX of the ASME Code and the Specification for Field Fabricated Storage Tanks (Reference 4).

The refueling water storage tank is designed as a Class I component, as described in Section 2.5, to withstand design seismic loading in accordance with the design stress criteria of ASME Code Section III, Figure N-414, *Nuclear Vessels*. The connecting piping is designed to withstand seismic loading to ensure the functioning of the system. The refueling water storage tank is provided with a manhole for inspection access.

Prior to unit operation, the water in the refueling water storage tank is cooled to a temperature of slightly below 45°F by either circulating the water through a heat exchanger that uses chilled water from the chilled water subsystem of the component cooling system (Section 9.4) or by using mechanical refrigeration units. Mechanical refrigeration units then maintain the tank water below 45°F. The tank is insulated. The refueling water storage tank also has a nozzle connection that supplies water to the safety injection system (Section 6.2).

The refueling water storage tank (RWST) is a passive component and is required only during a short period following an accident. It is provided with four channels of level indication, which provide signals to level indicators. The level indication range for the RWST is approximately 14,000 gallons at 0% level to approximately 399,000 gallons at 100% level. The RWST is maintained at greater than 387,100 gallons of borated water at or below a temperature of 45°F during normal plant power operations. Level transmitters provide input to a low level alarm and an empty alarm when RWST level drops below these respective setpoints. When two of four channels have sensed a low RWST level condition, an interlock signal is generated to allow for the start of the IRS and ORS pumps on a CLS Hi-Hi Actuation. Additionally, when two of four channels have sensed a low-low RWST level condition, a signal is generated to realign safety injection to the recirculation mode automatically. It takes approximately three minutes to realign the valves from injection to recirculation mode. The key values for the RWST assumed in the safety analysis are presented in Table 5.4-17. The safety analysis values are conservative with respect to plant operation.

The containment spray pumps are capable of supplying approximately 3200 gpm of borated water to two separate circular containment spray ring headers located approximately 96 feet above the operating floor in the dome of the containment structure and the common crane wall header at Elevation 95 ft. 6 in. Each pump is driven by an electric motor drive. The containment spray pumps are located adjacent to the containment structure and the refueling water storage tank. Each containment spray supply line to the containment contains a weight-loaded check valve. Should any water enter the manifolds during periodic testing, lines located after the check valves inside the containment drain the containment spray manifolds. The flow through the lines has been evaluated and the results of the containment accident analyses remain acceptable. A stainless steel filter is provided in the suction of each containment spray pump.

6.3.1.3.2 Recirculation Spray System

Each of the four recirculation spray subsystems shown in Figure 6.3-2 consists of a recirculation spray pump, a recirculation spray cooler, and a 180-degree spray ring header. The spray ring is located approximately 47 feet above the operating floor of the containment structure.

The four recirculation spray pumps take suction from a common containment sump strainer assembly. Each recirculation spray pump has a rated capacity of 3500 gpm. Two of the recirculation spray pumps and motors are located inside the containment structure (IRS pumps), and two pumps and motors are located outside the containment (ORS pumps). The containment sump strainer protects the IRS and ORS pump suction inlets when they are in recirculation mode. The four pumps are of the vertical deep-well type, and are of essentially the same design; however, the outside recirculation spray pumps have shaft extensions to permit locating the pump suctions at the level of the common containment sump, with the motors at an elevation slightly below ground grade. The pump motors inside the containment are selected to ensure operation under design-basis accident conditions.

The two recirculation spray pumps located outside the containment are fitted with a tandem mechanical seal arrangement. The space between the seal faces is filled with demineralized water that is maintained at a pressure slightly greater than the recirculation spray pump discharge pressure, thus preventing leakage of recirculation spray water that might be radioactive.

The recirculation spray water flows through recirculation spray coolers, where it is cooled by service water flowing under gravity, as discussed in Section 9.9. Since the recirculation spray water pressure in the coolers is greater than the service water, only outleakage can occur, and dilution of the borated water by service water in the containment is not possible. This ensures that the necessary cold shutdown margin by boron is maintained.

The service water from each cooler is monitored by means of radiation monitors to enable the defective subsystem to be shut down if outleakage occurs. Section 11.3.3 describes the process radiation monitoring devices and techniques used.

To ensure that adequate NPSH is available to the outside recirculation spray pumps, cold water is added to the spray pump suctions via bleed lines from the 10-inch containment spray risers inside the containment. Restriction orifices in these bleed lines result in a flow of approximately 310 gpm (actual flow varies with containment conditions) of chilled water from the refueling water storage tank to the outside recirculation spray pump suctions under normal operating conditions. This piping is inside containment and designed to withstand seismic effects and water hammer. Each containment spray pump can provide chilled water to either outside recirculation spray pump suction, by virtue of the recirculation spray suction cross-connect line.

Each inside recirculation spray pump suction receives a minimum analyzed flow of 300 gpm from the outlet of the respective inside spray heat exchanger. The piping runs are designed for seismic effects and water hammer. A restriction orifice is provided to obtain the minimum 300-gpm flow back to each pump suction. Material and installation are consistent with the design for the recirculation spray subsystem.

A flow rate of 3100 gpm for each of the inside recirculation spray pumps, and 2900 gpm for each of the outside recirculation spray pumps are used for containment analysis. With these pump flow rates, the minimum spray flow of 2800 gpm for each of the inside pump spray headers (i.e., minimum 3100-gpm pump flow less 300-gpm recirculation flow) and 2900 gpm for each of the outside pump spray headers is achieved. Minor variations in the inside recirculation spray and outside recirculation spray flowrates are acceptable, provided that 5700 gpm from the spray nozzles for each train is maintained to meet the requirements for the design basis accident.

Figure 6.3-5 is an isometric view that illustrates a typical arrangement of the outside recirculation spray pumps and the low-head safety injection pumps.

6.3.1.3.3 Containment Sump Strainer

The containment sump strainer protects the IRS, ORS, and LHSI pump suction inlets when they are in recirculation mode. The strainer assembly consists of modules with fins that are designed to prevent debris, large enough to clog spray nozzles, from reaching the recirculation spray subsystems. Water from the containment floor is filtered as it passes through perforated fins and into the modules. The filtered water flows through the modules to the pump suction inlets. Two separate strainer assemblies are provided, one for the four RS pumps and one for the two LHSI pumps. All components of the strainer assembly are designed to the Seismic Class I requirements.

The entire containment sump strainer assembly is raised off of the floor. The bottom of the RS strainer is six inches off the floor. The SI strainer is located on top of the RS strainer, so it sits approximately 19 inches off the floor. Since the strainer is raised off of the floor, heavy pieces of debris are prevented from reaching the fins and blocking them.

The fins filter the water as it flows into the strainer assembly and to the pumps. The fins have holes that are smaller than the size of the smallest nozzle orifice in the recirculation spray header. The finned perforated area performs the same function as the original inner sump screens. The fins are hollow tubes, which are perforated with holes having a nominal diameter of 1/16 inch. The total area of perforations through the fins is approximately 2550 ft^2 for the RS strainer and 900 ft^2 for the LHSI strainer. The perforated area of the finned strainer assembly is significantly higher than that of the removed sump screens, so the probability of the strainer becoming completely blocked is not considered to be credible. Large debris (non-buoyant) generated in other areas of containment would not be transported to the strainer because the flow velocity of the sump fluid is very low and could not lift the large dense pieces of debris. In addition, the containment floor is sloped away from the new containment strainer toward the center of containment.

The strainer is located in an area outside the crane wall. There are no high energy pipe lines overhead, so jet impingement or pipe whip from a high energy line break (HELB) is not a concern. In addition, missiles resulting from a HELB accident, for which sump recirculation is required, would not occur close enough to the strainer to damage it.

The strainer is designed to withstand the full debris load during all design basis conditions without collapse or structural damage. The strainer assembly is designed to withstand the effects of the Operating Basis Earthquake (OBE) and Design Basis Earthquake (DBE) events applicable to the containment floor elevation (-)27’-7”.

6.3.1.3.4 Containment Spray and Recirculation Spray Headers

The arrangement and sizes of the spray nozzles in the containment spray and recirculation spray subsystems have been accounted for in the determination of the spray effectiveness for these subsystems. With the inclusion of another containment spray subsystem header, new high volume nozzles were installed. The location and number of nozzles used was designed to ensure optimum spray droplet size and trajectory with the present spray pumps and system flow characteristics and to prevent excessive spray overlap that is ineffective. The overall nozzle arrangement was designed so that some of the nozzles cover a vertical annulus measuring 15 feet horizontally on either side of the spray headers. The remainder of the nozzles cover the containment volume outside the annulus.

CS spray headers. The CS spray headers contain 234 spray nozzles. The spray nozzles are sized to properly atomize the spray water to maximize the total surface area while minimizing the potential for becoming clogged by foreign matter. The spray pattern created from the spray rings forces an air flow in the containment that goes down along the outside and up the middle. The air flow assists in cooling the complete volume of the containment.

There are two independent 360-degree spray headers and one common 360-degree spray header which is located between the containment wall and the polar crane wall.

RS spray rings. There is one 180-degree spray ring for each RS subsystem. Each spray ring is a semicircular eight-inch pipe that contains 195 equally spaced sites, with 1 or 2 nozzles at each site for a total of 293 spray nozzles per header, to atomize the RS water. The inside and outside RS subsystem spray rings are arranged to form two complete 360-degree circular rings. The ESF train A and B subsystems are arranged so that the two RS subsystems in a single train provide 180-degree spray. The RS spray rings have spray nozzles that are oriented to obtain a wide distribution of varying size spray droplets. This provides adequate containment spray coverage.

In addition to the new spray headers, the Type 1HH30100 nozzles in the inside and outside recirculation spray headers have been plugged. The plugging of the nozzles increases the recirculation spray thermal effectiveness to at least 95%.

The three Model 1713A nozzles in each refueling water storage tank have been replaced with the Model 1708A nozzles. This has been done to maintain conservatism by ensuring that the most restrictive portion of the system is tested during the verification test of the containment spray system. The Spraco Model 1708A nozzles have the smallest orifice diameter and are, therefore, the most likely to become clogged if any solids were entrained within the spray fluid. See Section 6.3.1.5.2 for the method of testing.

The “A” containment spray pump suction line contains a normally isolated BDB piping connection. This piping connection allows for a portable pump to either utilize the RWST as a suction source or refill the RWST, based on the configuration of the pump, during a beyond design basis external event (BDBEE).

The entire spray system is constructed of corrosion-resistant materials, primarily stainless steel. However, other materials are used where suitable, such as brass for the spray nozzles. The system design pressure is 150 psig.

6.3.1.4 **Evaluation**

6.3.1.4.1 Low Head Safety Injection and Recirculation Spray Containment Sump Strainers

NRC Bulletin 93-02 (Reference 1) required licensees to evaluate their facilities for the potential of fibrous material installed or stored in containment to detrimentally affect the functional capability of the Emergency Core Cooling System (ECCS) due to the clogging of suction strainers. The potential effects of fibrous debris on the Surry ECCS was evaluated and provided to the NRC in response to the Bulletin (Reference 2).

NRC Generic Letter GL 2004-02 (Reference 5) required licensees to perform an evaluation of the Emergency Core Cooling and Recirculation Spray (RS) Systems function in light of the potential impact of debris blockage on the existing containment sump screens. The potential debris blockage could result in a debris-induced loss of NPSH margin during sump recirculation. The potential impact of the debris generation and transport was evaluated and provided to the NRC in response to the Generic Letter (Reference 8).

The response resulted in the completion of several evaluations and tests to determine the impacts of the new requirements in GL 2004-02 to the original containment sump screens. This resulted in the replacement of the original containment screen assembly with a passive sump strainer design.

Evaluations and tests were performed in accordance with the NEI 04-07 (Reference 6) and its associated SER (Reference 7) to ensure that the postaccident debris blockage will not impede the operation of the RS and LHSI systems in the recirculation mode.

The following evaluations and tests were performed.

- Evaluation of debris generation caused by a LOCA
- Evaluation of debris transport to the strainer
- Evaluation of downstream effects of blockage and wear on components
- Evaluation of downstream wear effects on system performance
- Evaluation of downstream effects of blockage and chemical precipitation on fuels
- Evaluation of chemical effects to quantify chemical species
- Strainer hydraulic test to determine head loss due to debris and chemical effects
- Strainer fiber bypass test

The following types of materials were determined to become debris and chemical effects contributors in the event of a LOCA or high energy line break:

- Piping and Equipment Insulation
- Insulation Jacketing
- Missile Barrier Penetration Seals
- Qualified Coatings
- Unqualified/Damaged Coatings
- Latent Debris
- Fire Stop Materials
- Foreign Material
- Aluminum Materials
- Coated and Uncoated Concrete

The amount of debris generated during a LOCA was determined such that it would maximize the head loss across the containment sump strainer during recirculation mode. A number of breaks in each high pressure system that relies on recirculation were considered to bound variations in debris generation by size, quantity, and type of debris. The breaks were selected on the piping located in the steam generator cubicles and in the pressurizer room. These areas contain the large diameter high-energy piping and largest quantity of insulation and potential debris that could be exposed to a break. All LOCA and high energy line break generated debris are conservatively evaluated as falling to the containment elevation (-)27’-7”.

Debris created by a LOCA inside the lower reactor cavity would be expected to reach the containment sump strainer through a 12-inch diameter drain hole core drilled through the primary shield wall plug in the lower portion of the reactor cavity (Incore Sump Room). The debris generated would have to pass through the narrow gap between the reactor vessel and the neutron shield tank before reaching the drain opening and convey to the containment sump strainer.

A Computational Fluid Dynamic (CFD) model of the Surry containment was developed to determine the containment spray flow velocities and water currents within containment. Based on these flow rates, debris types were determined not to transport, to transport in fractions, or transport in total. A quantity of generated debris that would be transported to the containment sump strainer was determined.

As a part of the chemical effects evaluation, the plant specific parameters were compared to the Integrated Chemical Effects Test (ICET) parameters to establish whether the ICET tests bounded the plant parameters as required by the NRC SER on NEI 04-07 evaluation guidance.

The chemical species that are expected to be released into the containment sump during the 30 days following a LOCA were quantified. These quantities were the basis for determining the quantities of the specific test chemicals used in the strainer testing.

The strainer manufacturer has performed various hydraulic tests that simulated the actual debris loading and chemical conditions specific to the Surry Power Station based on the debris generation, debris transport, and chemical effects evaluations. Fibrous, particulate, and chemical debris were added to a test rig to simulate the plant-specific chemical environment present in the water of the containment sump. Each test was operated for more than 30 days after the formation of the debris bed and initial chemical addition at specified temperatures and flow rates to assess chemical precipitate formation and head loss change. These tests sized the strainer and verified that adequate NPSH is available to support the operation of the LHSI and RS pumps during recirculation mode.

The downstream effects evaluation was performed in accordance with WCAP-16406-P (Reference 9) to determine RS System and ECCS components that are susceptible to blockage and wear due to debris bypass post-LOCA. The evaluation determined that downstream RS System and ECCS components have sufficient flow clearances in the flow paths that would allow debris to pass through openings without causing blockage.

The downstream effects evaluation determined the effects of erosive and abrasive wears on RS System and ECCS components, overall system hydraulic performance, and the system piping vibration. A wear model was developed in accordance with methodology provided in WCAP-16406-P to assess the amount of wear in RS System and ECCS components based on the initial debris concentration in the pumped fluid, the debris concentration depletion, the hardness of the wear surfaces, and the mission time. The results for wear on the manually throttled valves, orifices, containment spray nozzles, and RS heat exchanger were determined acceptable in accordance with criteria set forth in WCAP-16406-P. The dynamic performance of RS System and ECCS pumps is evaluated for wear effects on pump components. The evaluation concluded that the RS System and ECCS pumps meet the acceptance criteria for vibrations specified in WCAP-16406-P and therefore, will operate satisfactorily without excessive vibrations for a period of 30 days post-LOCA. The degraded hydraulic performance curves for RS System and ECCS pumps were developed resulting from erosive and abrasive wears of pump internal components. Changes in system resistance due to wear of system components such as orifices and manually throttled valves and degraded pump hydraulic performance were used as input to system models to evaluate whether minimum system flow requirements would be met. Modeling was then used to establish whether the degraded system resistance would cause the pumps to operate in an unacceptable run out condition. The results of the evaluation indicated that RS System and ECCS pumps are acceptable with respect to run out flow and will meet the minimum flow requirement to depressurize the containment and cool the reactor core for a period of 30 days post-LOCA.

System vibration analysis was performed to evaluate the effects of wear of RS System and ECCS piping and components downstream of the containment sump strainer. The RS System and ECCS pumps were also evaluated for hydraulically induced vibrations using maximum flows derived in the hydraulic analysis portion of the evaluation and for pump rotor dynamic analysis affected by the erosive and abrasive wears of pump internal components due to debris in the pumped fluid. The effects of wear on net positive suction head (NPSH) requirements and availability were considered to ensure cavitation would not induce unacceptable pump vibration. The evaluation indicated that the expected erosive and abrasive wear of the RS System and ECCS piping would be negligible after 30 days post-LOCA and therefore, the structural characteristics of the systems considered are not impacted. The RS System and ECCS pumps are acceptable for hydraulically induced vibration and meet the acceptance criteria for rotor dynamic vibration documented in WCAP-16406-P (Reference 9). Pump cavitation will not occur since the available NPSH exceeds the required NPSH for all RS System and ECCS pumps. Therefore, based on the acceptability of downstream wear effects and pump vibration and cavitation analyses, the evaluation concluded that the RS System and ECCS piping and components are not susceptible to excessive vibrations due to post-LOCA downstream wear.

The downstream effects evaluation was performed for fuels in accordance with WCAP-16793-NP (Reference 10) to determine the impact of fibrous, particulate, and chemical precipitant debris on the fuel and long-term cooling. The evaluation demonstrated that all of the WCAP evaluations and conclusions are directly applicable to Surry Units 1 and 2. This provided reasonable assurance that for both units, long-term core cooling will be established and maintained post-LOCA considering the presence of debris in the Reactor Coolant System and core.

Based on the above evaluations and tests, the area of perforations in the strainer was determined to be sufficient such that under full debris loading conditions there would be adequate NPSH available to the RS and LHSI pumps during accident conditions.

The change in buffer from sodium hydroxide to sodium tetraborate decahydrate has been evaluated and determined to not adversely affect the conclusions of the above evaluations and tests.

6.3.1.4.2 Recirculation Spray Nozzles

The spray system consists of two separate but parallel containment spray rings located in the containment dome and one common containment spray ring located outside the crane wall, plus four separate but parallel recirculation spray headers, each of approximately 50% capacity. The use of a separate spray header connected to the discharge of each pump results in a fixed flow rate, and allows for optimized selection of spray nozzle sizes. This arrangement gives the optimum combination of small spray particles for maximum heat transfer and larger particles for better coverage toward the center and sides of the containment. In addition, this arrangement also ensures that a failure of a component in any one subsystem does not affect the operational capability of the other subsystems.

The methods of preventing the plugging of spray nozzles in the two systems vary. For each containment spray train, the materials of construction, as well as the pump suction filter, prevent nozzle plugging. A method of nozzle testing is provided in the refueling water storage tank to ensure that no particulates that could plug the containment spray nozzles collect in the tank. Despite this precaution and regardless of strainer perforation size, some types of particles could conceivably pass lengthwise through the strainer and cause clogging of a spray nozzle. However, since the strainer perforations are smaller than the smallest spray nozzle opening, such an occurrence is considered to be highly improbable.

The containment sump strainer assembly is designed such that a single assembly provides filtered borated water to all four RS System pumps, as discussed in Section 6.3.1.3. The design feature of the strainer prevents complete failure of all suction points of the RS System. The strainers are raised off of the floor, which prevents large debris (non-buoyant) from reaching the fins and blocking them. It provides significantly large area of fin perforations that reduces the approach velocity and possibility of the strainer becoming completely blocked.

Since the redundant capacity of the recirculation spray subsystems increases from 100% after a loss-of-coolant incident to 400% to 1000% 1 day after an incident, plugging that could only occur on a long-term basis would have no significant effect on the capability of the subsystems.

6.3.1.4.3 Recirculation Spray Heat Exchangers

Initially, the heat exchangers of the recirculation spray trains are clean and dry, with maximum heat transfer capability. For long-term operation, on the order of weeks or months, there may be some fouling of the tubes on the service water side, with resultant loss in heat transfer capability. This loss of heat transfer capability is more than offset by the decrease in heat load resulting from decreasing decay heat production. One day after a LOCA, the decrease in the residual heat production rate is such that each train has sufficient heat removal capacity to hold the containment at subatmospheric pressure. With a maximum service water temperature of 100°F, the recirculation spray subsystem design is conservative. There is a minimum 100% reserve capacity in recirculation spray at the onset of an accident. Within one day after the LOCA, the reserve capacity exceeds 400%.

The recirculation spray heat exchangers are designed to Section VIII, Division I of the ASME Code, and have welded construction at all points where there could be a potential for leakage of radioactive recirculation spray water into the service water. The operating pressure of the recirculation spray water is greater than that of the service water, with a differential of approximately 100 psi; therefore, any leakage flow from the recirculation spray subsystem is into the service water system. The service water is monitored by radiation monitors to detect leakage from the defective subsystem (Section 11.3.3). If leakage above an allowable level is detected, the defective subsystem is shut down by manual operation of remote motor-operated valves that isolate the recirculation spray cooler. As a result of the above pressure difference, inleakage of non-borated water into the containment, causing dilution of the borated water in the containment, is not possible.

6.3.1.4.4 Recirculation Spray Pumps

Recirculation through the outside recirculation spray pumps presents a possibility of leakage through valve packings and from leaks in the suction and discharge piping of the pump. Valve designs are selected to reduce this potential leakage to a negligible amount. Leaks in the suction and discharge piping are controlled as follows:

1. Large leaks in the discharge piping of the recirculation spray pumps are detected by variations in the recirculation spray pump discharge pressure readings in the control room. A large decrease in pump discharge pressure indicates a pipe break and the operator in the control room could then remote-manually isolate that pump.

2. Large leaks in the suction piping in the valve pit will be detected by the following devices, which indicate in the control room: (1) high liquid level annunciation instrumentation located in the valve pit, (2) exhaust ventilation radiation monitoring, (3) outside recirculation spray pump discharge pressure and/or (4) outside recirculation spray pump motor amperage. Upon detection of a potential leak from any of these sources, control room personnel will identify the affected flow path by observation of the system parameters. Upon identification of the leaking spray line, the control room operator can remote manually isolate the leaking spray line, leaving one recirculation spray loop operable. In the case of small leaks, specific detection of a leak is not possible; however, the ventilation air from the structure (Figure 6.3-5) enclosing the piping outside the containment is discharged to the atmosphere through ventilation vent no. 2, and is automatically diverted through charcoal filters on a high-high containment pressure signal.

A periodic inspection is made of all potential points of leakage. Table 6.3-2 summarizes the potential leakage from the recirculation spray subsystem. The potential for leakage of pumped fluid from the recirculation spray pumps is minimized, due to the manner in which the pump shaft is sealed. Two mechanical seals are arranged in tandem, with a seal fluid between them. The seal fluid is supplied from a reservoir arranged in such a manner that the pressure of the seal fluid is slightly (about 1 psi) above the pumped fluid pressure at the inboard side of the inboard seal at all times. With this arrangement, assuming the inboard seal fails, seal fluid leaks through the failed seal while the other seal remains available to prevent the escape of pumped fluid to the atmosphere. A level alarm on the reservoir provides an indication of a seal failure.

A failure-mode analysis for the components of the spray system is included in Table 6.3-3.

Recirculation Spray Pump NPSH

The transient analysis of the available NPSH for the recirculation spray pumps is performed with the GOTHIC computer program. The analysis assumptions are similar to those discussed in Section 6.2.3.11 for the calculation of LHSI pump available NPSH during the recirculation phase. The minimum available NPSH generally occurs following a DEHLG. The minimum NPSH available to the outside recirculation spray pump occurs during maximum safeguards conditions, that is with two containment spray pumps supplying cold water to both outside recirculation spray pumps, concurrent with the coldest service water temperature. This combination of parameters results in the most rapid containment depressurization rates early in time and, therefore, relatively low containment pressure when the pumps start. The minimum NPSH available to the inside recirculation spray pumps occurs following a DEPSG with maximum safeguards and no single failure.

The required NPSH for each recirculation spray pump is listed in Table 6.2-13. The minimum available NPSH following the DBA is also listed in the table.

The available NPSH transients for the outside and inside recirculation spray pumps are shown on Figure 6.3-6 and Figure 6.3-10, respectively. The height of water on the floor is also shown on both figures. The NPSH analyses account for the 12" Incore Sump Room drain in the determination of containment water level. The available NPSH versus time is shown on Figure 6.3-6. The transient containment pressure and pump suction vapor pressure is shown on Figure 6.3-7. The containment sump temperature and vapor temperature are shown on Figure 6.3-8. The recirculation spray heat exchanger duty is shown on Figure 6.3-9. This information is also provided for the analysis of the inside recirculation spray pump available NPSH in Figures 6.3-10 through 6.3-13, respectively for the DEPSG break with full safeguards.

6.3.1.5 **Tests and Inspections**

6.3.1.5.1 Containment Spray Subsystem

Two types of tests are performed on the containment spray subsystem. First, during and after installation, it was tested to ensure that design criteria were met. Second, provisions have been made for testing the subsystem throughout the life of the unit to ensure that it is operational.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

During the construction period, the containment spray headers were fitted with blind flanges that allowed the connection of temporary drain lines for initial testing of the subsystem. After the subsystem was completely installed, temporary connections were made to the blind flanges on the spray headers and pipe plugs were placed in the spray nozzle sockets. The containment spray pumps were started and operated over their entire range of flow, circulating water through the spray header supply lines to the spray headers and out the temporary drain connections. This provided a full-system capability test to ensure that the system met the flow requirements. It also provided for a flush of the system to remove any particulate matter that could plug the spray nozzles at a future time. At the completion of this test, the temporary drain connections were removed, the blind flanges replaced, the pipe plugs removed, the nozzle pipe nipple inspected, and the spray nozzles installed. Verification of the containment spray system response to a CLS HI-HI signal was performed during the CLS HI-HI logic testing that was also completed prior to initial reactor operation. The subsystem was then ready for operation.

With a system flush to remove particulate matter before the installation of spray nozzles, and with corrosion-resistant nozzles and piping, it is not considered credible that a significant number of nozzles would plug during the life of the unit to reduce the effectiveness of the subsystem; therefore, no means are provided for intermittent testing of the containment spray header nozzles with water. Provision was made to perform an initial air flow test on the containment spray subsystem nozzles. A compressed air source was connected to the spray header piping, and the air flow through each nozzle was individually measured by using a funnel and tubing arrangement to channel the air flow from each nozzle through a flow meter.

The containment spray subsystem nozzles will be subjected to an inspection or smoke or air test following maintenance or an activity which could cause blockage to provide indication that plugging of the nozzles has not occurred.

Means have been provided for intermittent testing of the containment spray pumps. This testing is performed periodically by opening the normally closed valves on the spray pump recirculation line, thus returning water to the refueling water storage tank. The operation of the subsystem allows the pumps to operate and recirculate a quantity of water back to the refueling water storage tank. The discharge into the refueling water storage tank is divided into two fractions, one for the major portion of the recirculation flow and the other to pass a small quantity of water through test nozzles, which are identical with those used on the containment spray headers. The purpose of the recirculation through test nozzles is to ensure that there is no particulate material in the refueling water storage tank and the containment spray subsystem that could plug or cause deterioration of the spray nozzles. The flow rate through the test nozzles is monitored and compared to the previously established flow rate obtained with the new nozzles. The presence of any particulate material that could cause plugging will be apparent through a reduction in flow rate through the nozzles. The weight-loaded check valves inside the containment are tested periodically by pressurizing the pump discharge lines with air and checking for a flow from the drain line.

Electrical insulation resistance tests are performed during the lifetime of the CS motors to verify the integrity of the insulation. Periodic tests are also performed to ensure the motors remain in a reliable operating condition.

The Containment Spray System is subject to the applicable inservice inspection and inservice testing requirements of the ASME Code, as required by 10 CFR 50 (Code of Federal Regulations, Title 10, Part 50).

6.3.1.5.2 Recirculation Spray Subsystem

The initial test for the recirculation spray subsystem included a system flush, a pump shutoff head verification, and an air flow test of the spray header. This assured that the system was cleared of debris, the pump capacities met design, and that the spray headers and nozzles were unobstructed.

The inside and outside recirculation spray pumps were designed to be operated dry for a short period of time (one minute) to verify operability. The physical arrangement of the outside recirculation spray pumps (vertical deep well with 52-foot casing height along with the permanently installed recirculation line) allows for periodic flow testing. The outside pumps are flow tested by closing the pump suction and discharge isolation valves, filling the pump casing with water and recirculating through recirculation piping from the pump discharge back to the pump casing. The inside recirculation spray pumps do not have extended pump casings or suction and discharge isolation valves. The inside recirculation spray pumps take suction from the containment sump which is maintained wet during normal operation to provide a water seal to reduce the potential for pressure locking the LHSI pumps containment suction motor operated valves (Reference 3). In order to provide for periodic flow testing of the inside recirculation spray pumps, the system is provided with recirculation piping and removable sump panels which are installed around the pump suction area during testing. The inside recirculation spray pumps are flow tested after installing and filling the temporary sump and connecting the recirculation piping using flanged spool pieces (Reference Drawing 6.3-2). Periodic flow testing of the inside and outside recirculation spray pumps is required to satisfy the inservice testing requirements of ASME Code. Due to the complexity and time required to perform flow testing of the inside recirculation spray pumps, this test is only performed during refueling outages.

The recirculation spray subsystem nozzles will be subject to an inspection or smoke or air test following maintenance or an activity which could cause blockage to provide indication that plugging of the nozzles has not occurred. The testing of system controls is discussed in Section 7.5.

Electrical insulation resistance tests are performed during the lifetime of the RS motors to verify the integrity of the insulation. Periodic tests are also performed to ensure the motors remain in a reliable operating condition.

The Recirculation Spray System is subject to the applicable inservice inspection and inservice testing requirements of the ASME Code, as required by 10 CFR 50 (Code of Federal Regulations, Title 10, Part 50).

6.3 REFERENCES

1. NRC Bulletin No. 93-02: *Debris Plugging of Emergency Core Cooling Suction Strainers,* dated May 11, 1993.
2. Letter from Virginia Electric and Power Company to the NRC, dated June 10, 1993, Serial No. 93-307, *Response to NRC Bulletin 93-02.*
3. Letter from Virginia Electric and Power Company to USNRC dated February 7, 1996 (Serial No. 95-566A), *Generic Letter 95-07 Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves, Surry and North Anna Power Station.*
4. Stone & Webster Specification NUS-258, *Specification for Field Fabricated Storage Tanks*, Revision 2.
5. NRC Generic Letter GL 2004-02, *Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors*, dated September 13, 2004.
6. Nuclear Energy Institute (NEI) Document NEI 04-07, *Pressurized Water Reactor Sump Performance Evaluation Methodology*, dated December 2004.
7. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to NRC Generic Letter 2004-02, *Nuclear Energy Institute Guidance Report Pressurized Water Reactor Sump Performance Evaluation Methodology*.
8. Letter from Dominion Resources Inc. to the NRC, dated September 1, 2005, Serial No. 05-212, *Response to NRC Generic Letter 2004-02*.
9. Westinghouse Document WCAP-16406-P, Revision 1, *Downstream Wear Evaluation Methodology for Containment Sump Screens in Pressurized Water Reactors*.
10. Westinghouse Document WCAP-16793-NP, Revision 0, *Evaluation of Long-Term Cooling Considering Particulate, Fibrous and Chemical Debris in the Recirculating Fluid.*
11. U.S. Nuclear Regulatory Commission Standard Review Plan NUREG-0800, Chapter 6, Section 6.1.1, Rev 2, *Engineered Safety Features Materials.*
12. WCAP-16596-NP, Revision 0, *Evaluation of Alternative Emergency Core Cooling System Buffering Agents*, dated July 2006.

Table 6.3-1
SPRAY SYSTEM COMPONENT DATA

Containment Spray Pump	
Number	4 (2 per unit)
Type	Horizontal centrifugal
Rated flow	3200 gpm
Rated head	225 ft
Brake horsepower	223 hp
Seal	Mechanical
Design pressure	250 psig
Material	
Pump casing	A351-CF8
Shaft	SS 316
Impeller	A351-CF8
Containment Spray Pump Motor	
Number	4 (2 per unit)
Horsepower	250 hp
Electrical characteristics	460V, 3 phase, 60 cycle
Service factor	1.15
Insulation	Class B
Refueling Water Storage Tank	
Number	2 (1 per unit)
Technical Specifications minimum volume	387,100 gal (1); 387,100 gal (2)
Boron concentration	2300-2500 ppm
Design pressure	Hydraulic head
Design temperature	150°F
Operating pressure	Hydraulic head
Nominal operating temperature	35-45°F [a]
Material	ASTM A240, SS 304L
Design code	API STD-650
Recirculation Spray Pump (inside containment)	
Number	4 (2 per unit)
Type	Vertical centrifugal
Rated flow	3500 gpm
Rated head	245 ft
Brake horsepower	293 hp
Seal	Throttle bushing

a. The mechanical refrigeration units are designed to cool the contents of the RWST to a temperature between 35°F and 43°F. The maximum RWST temperature permitted by the Technical Specifications is 45°F.

Table 6.3-1 (CONTINUED)
SPRAY SYSTEM COMPONENT DATA

Recirculation Spray Pump (inside containment) (continued)		
Material		
Shaft	17-4 precipitation-hardened stainless steel	
Pump casing	A351-CF8	
Impeller	A351-CF8	
Recirculation Spray Pump Motor (inside containment)		
Number	4 (2 per unit)	
Horsepower	300 hp	
Electrical characteristics	460V, 3 phase, 60 cycle	
Service factor	1.15	
Insulation	Encapsulated - custom polyseal	
Recirculation Spray Pump (outside containment)		
Number	4 (2 per unit)	
Type	Vertical centrifugal	
Rated flow	3500 gpm	
Rated head	230 ft	
Brake horsepower	274 hp	
Seal	Tandem mechanical	
Material		
Shaft	17-4 precipitation-hardened stainless steel	
Pump casing	A351-CF8	
Impeller	A351-CF8	
Recirculation Spray Pump Motor (outside containment)		
Number	4 (2 per unit)	
Horsepower	300 hp	
Electrical characteristics	460V, 3 phase, 60 cycle	
Service factor	1.15	
Insulation	Encapsulated	
Recirculation Spray Coolers		
Number	8 (4 per unit)	
Design duty	55,534,520 Btu/hr, each	
	Shell	Tube
Fluid flowing	Recirculation spray water	Service water
Design pressure	150 psig	150 psig
Design temperature	250°F	250°F
Operating pressure	100 psig	20 psig
Operating temperature	200°F	92°F
Material	Stainless Steel 304	Titanium

Table 6.3-1 (CONTINUED)
SPRAY SYSTEM COMPONENT DATA

Recirculation Spray System Strainer Assembly	
Number	1 (for both ORS and IRS Systems)
Material	SS 304
Design Code	ASME Section III, Subsection NF, Class 3
Structural DP	9.0 psid
Perforations	0.0625 in. diameter
Operating Pressure	9.0-59.7 psia
Operating Temperature	75-280°F
Fluid Flowing	Borated water
Sodium Tetraborate Decahydrate Baskets	
Number	14 (7 per unit)
Material	
Basket	SS 304
Wheels	Duplex SS 2205
Nominal size (internal dimensions)	6 ft x 5 ft x 1.5 ft
Operating Pressure	9.0-59.7 psia
Operating Temperature	75-280°F
Technical Specification minimum	10760 lbm (total per unit)
Chemical Specification	
B_2O_3	36.5-38.3%
Equivalent $Na_2B_4O_7 \cdot 10H_2O$	99.9-105.0%
Na_2O	16.2-17.1%
SO_4	≤ 3.0 ppm
C1	≤ 0.4 ppm
Fe	≤ 2.0 ppm
Chemical Sieve Specification	
Standard No.	8
Retained	≤ 0.1%

Piping

Piping is designed to the Code for Pressure Piping, ANSI B31.1.

Valves

Recirculation Spray system valves are designed in accordance with ANSI B16.5, Steel Piping Flanges and Flanged Fittings, or ANSI B16.34, Steel Butt-Welded End Valves.

Table 6.3-2
TOTAL POTENTIAL EXTERNAL RECIRCULATION LOOP LEAKAGE TO ATMOSPHERE FROM THE RECIRCULATION SPRAY SYSTEM[a]

Item	Number of Units	Type of Leakage Control and Unit Leakage Rate Used in the Analysis	Uncollected Leakage (cc/hr)[b]	Leakage to Vent and Drain System (cc/hr)[b]
Recirculation spray pumps	2	No leakage of spray water due to tandem seal arrangement	0	0
Flanges		Assumed at 10 drops per minute per flange		
Pump	4		480	
Valves - bonnet to body (larger than Q in.)	4		460	
Valves - stem leakoffs	4	Backseated, double packing with leakoff - 1 cc/hr/in. stem diameter	0	16
Miscellaneous small valves	2	Flanged body, packed stem - one drop per minute	24	0
Total potential leakage			964	16

a. Based on two subsystems in operation under design-basis accident conditions.
b. The actual allowable leakage for each leakage control component may exceed the indicated leakage rate as long as the total external recirculation loop leakage does not exceed 3,000 cc/hr as required by Section 14.5.5.3.

Table 6.3-3
CONSEQUENCES OF COMPONENT MALFUNCTIONS

Components	Malfunction	Comments and Consequences
Containment spray pumps	Pump casing ruptures	The casing is designed for pumping the RWST contents which are maintained at approximately 45°F. Standard test pressure is 250 psig and maximum hydrostatic test pressure is 375 psig. These conditions exceed those which could occur during any operating conditions. The casings are made from cast stainless (ASTM A351-CF8). This metal has corrosion-erosion resistance and produces sound castings. The pumps conform to Class I design. Pumps are missile protected and may be inspected at any time. Rupture by missiles is not considered credible. Rupture of the pump casing is therefore not considered credible.
Containment spray pumps	Pump fails to start	The containment spray system has two parallel 100% capacity pumps. Sufficient capacity is provided by one pump in case of failure of the other pump.
Containment spray pump discharge valve	Valve fails to open	Redundant parallel valves are provided. Redundant valve carries the flow.
Containment spray pump discharge valve	Rupture of valve body	Valve body is designed for 150 lb. The castings are made from stainless steel; this material has corrosion-erosion resistance and produces sound castings. The valves are designed to be missile protected. Rupture of valve body is not considered credible.
Containment spray pumps	Weight-loaded check valve in pump discharge line sticks closed	Valve is checked periodically during refueling. In addition, parallel 100% capacity containment spray sub system is operable.
Containment spray piping	Pipe rupture	Piping is designed for 100°F temperature and 275 psig pressure. These conditions exceed those that could occur during operation. The piping is fabricated of Type 304 stainless steel; this metal has corrosion-erosion resistance. Piping is designed for Class I and is missile protected. Pipe rupture is not considered credible.
Recirculation spray pump	Pump fails to start	Four 50% rated capacity recirculation spray pumps are provided altogether.

Table 6.3-3 (CONTINUED)
CONSEQUENCES OF COMPONENT MALFUNCTIONS

Components	Malfunction	Comments and Consequences
Recirculation spray cooler	Tube or shell rupture	Four 50% rated capacity recirculation spray coolers are provided altogether. The recirculation spray coolers are designed to the ASME Code, Section VIII, Division 1. Rupture is considered unlikely. However, in the event of a rupture, motor-operated valves are provided to isolate the cooler and prevent further leakage. Another recirculation spray subsystem is used.
Outside recirculation spray pump	Rupture of pump casing	The casing is fabricated of ASTM SA452, Type 304 stainless steel; this metal is corrosion resistant. The casings are missile protected and set in concrete. Rupture of the pump casing is not considered credible.
Recirculation spray piping	Rupture of piping	Piping is fabricated of Type 304 and 316L stainless steel and designed to Class I. Piping is also missile protected. Rupture of piping is not considered credible. However, in case of pipe rupture for pipe lines to and from outside; recirculation spray pumps, isolation valves are provided.
Motor-operated valves	Loss of power to one valve due to failure of electric bus	Redundant valves are provided, electric power to valves is supplied from separate buses.
Automatic electric and control instrumentation trains to actuate consequence limiting safeguards equipment	Failure of one train	Redundant train will actuate redundant equipment.
Spray nozzles	Spray nozzles plugged	Filters are provided in the suction of the containment spray pumps. A strainer assembly with 0.0625-inch openings is provided in the suction of the recirculation spray pumps. The filters and strainer openings are small enough to prevent any material that could plug the spray nozzles from passing through.

Table 6.3-3 (CONTINUED)
CONSEQUENCES OF COMPONENT MALFUNCTIONS

Components	Malfunction	Comments and Consequences
Containment sump strainer modules and fins	Fin or strainer module failure	The fins and strainer modules are designed such that they can withstand full debris loading and have sufficiently large perforated fin area available to compensate for debris blockage. The strainers are capable of withstanding the force of full debris loading in conjunction with other conditions including seismic events.

Figure 6.3-1
CONTAINMENT SPRAY SUBSYSTEM

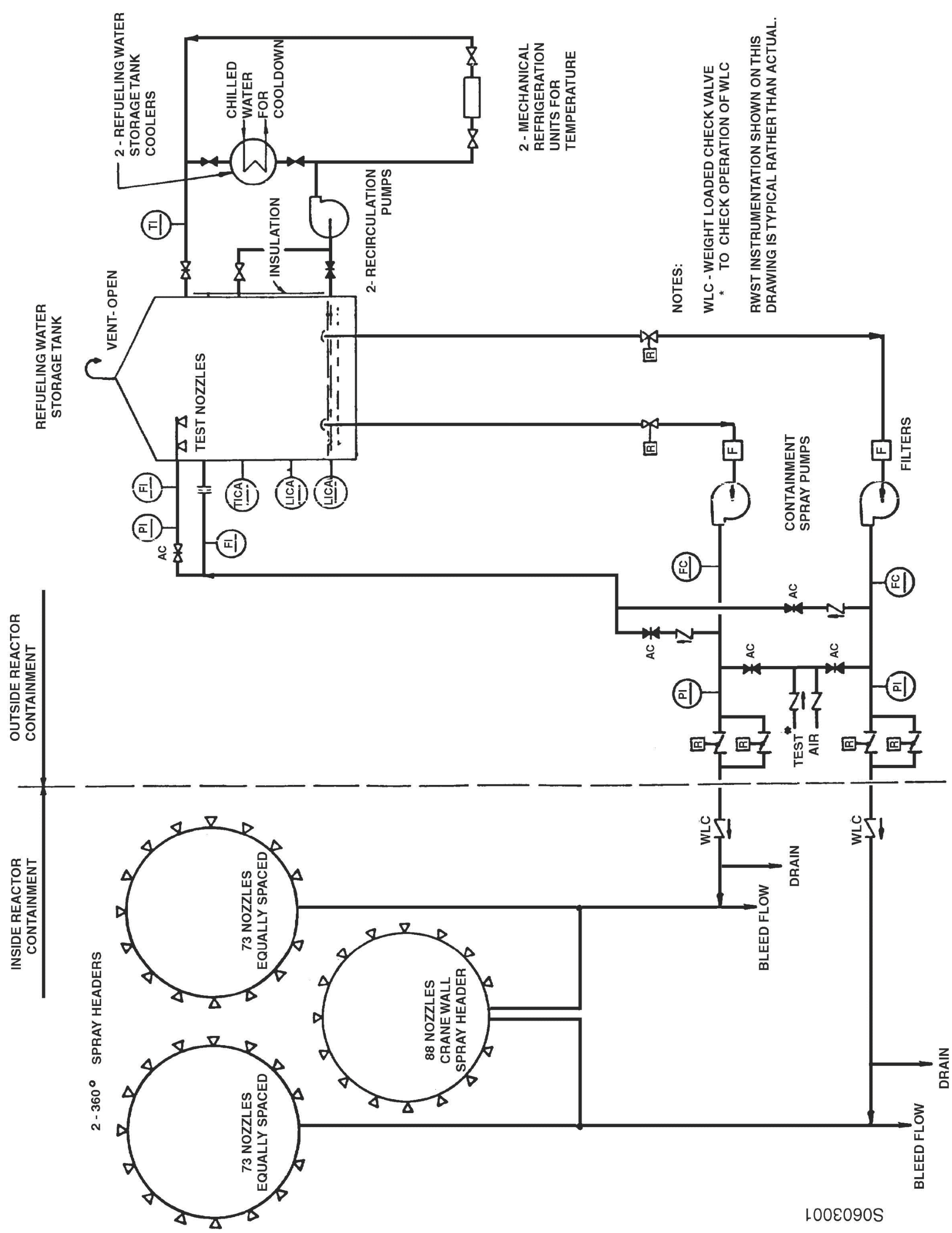


Figure 6.3-1b
DELETED

Figure 6.3-2
UNIT 1 RECIRCULATION SPRAY SUBSYSTEM

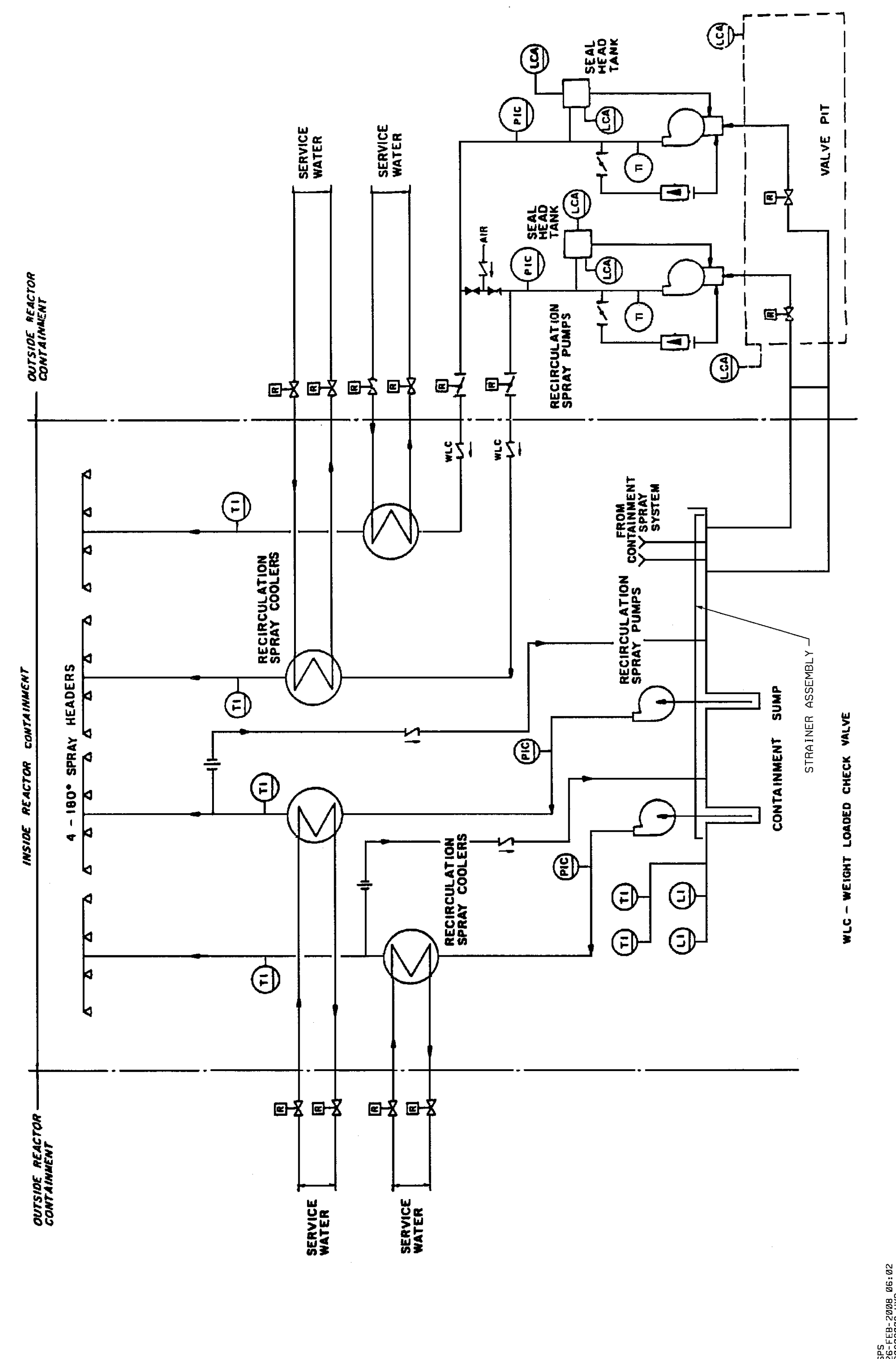


Figure 6.3-3
UNIT 2 RECIRCULATION SPRAY SUBSYSTEM

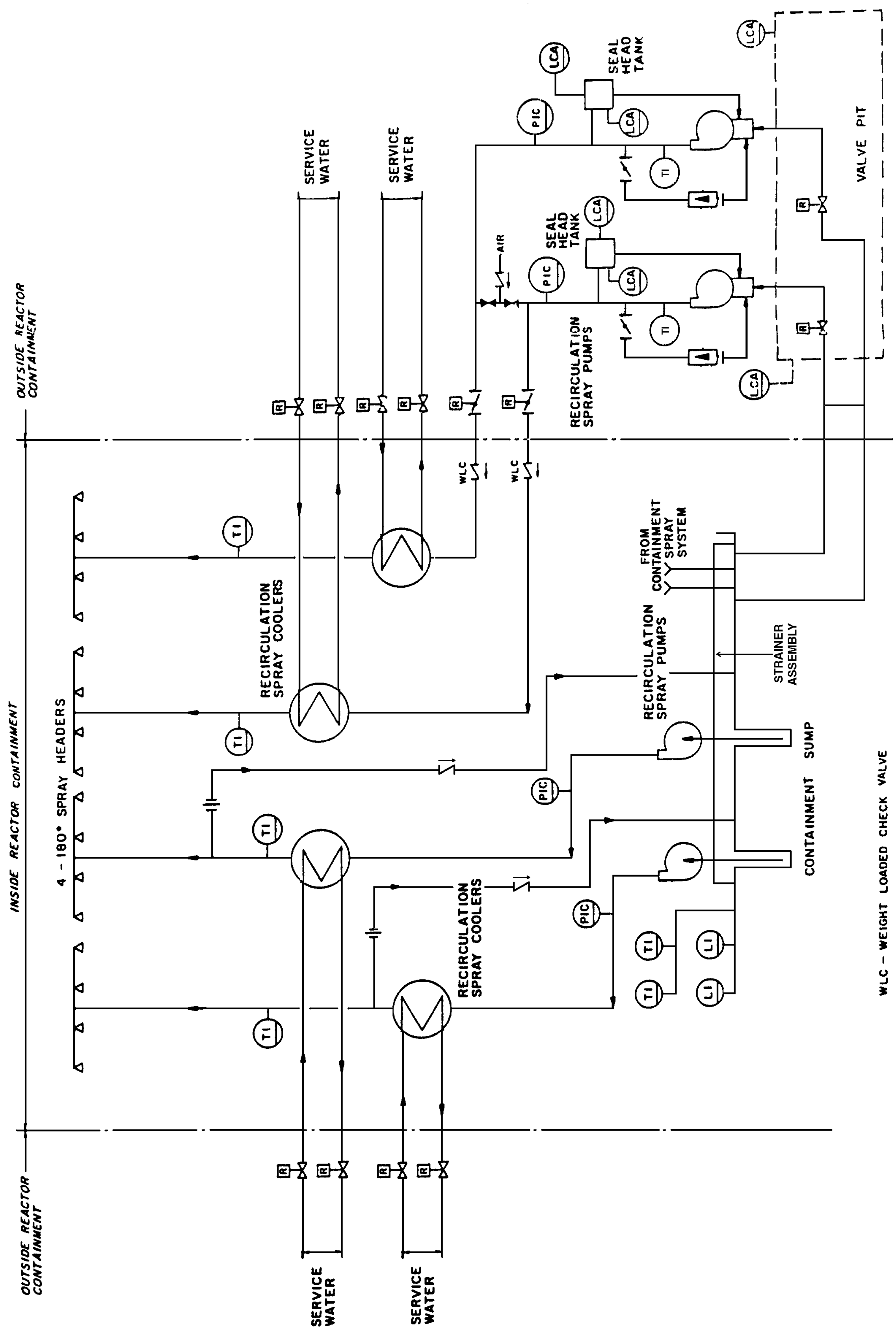


Figure 6.3-4
PIPING AND COMPONENTS ELEVATIONS SPRAY SYSTEMS

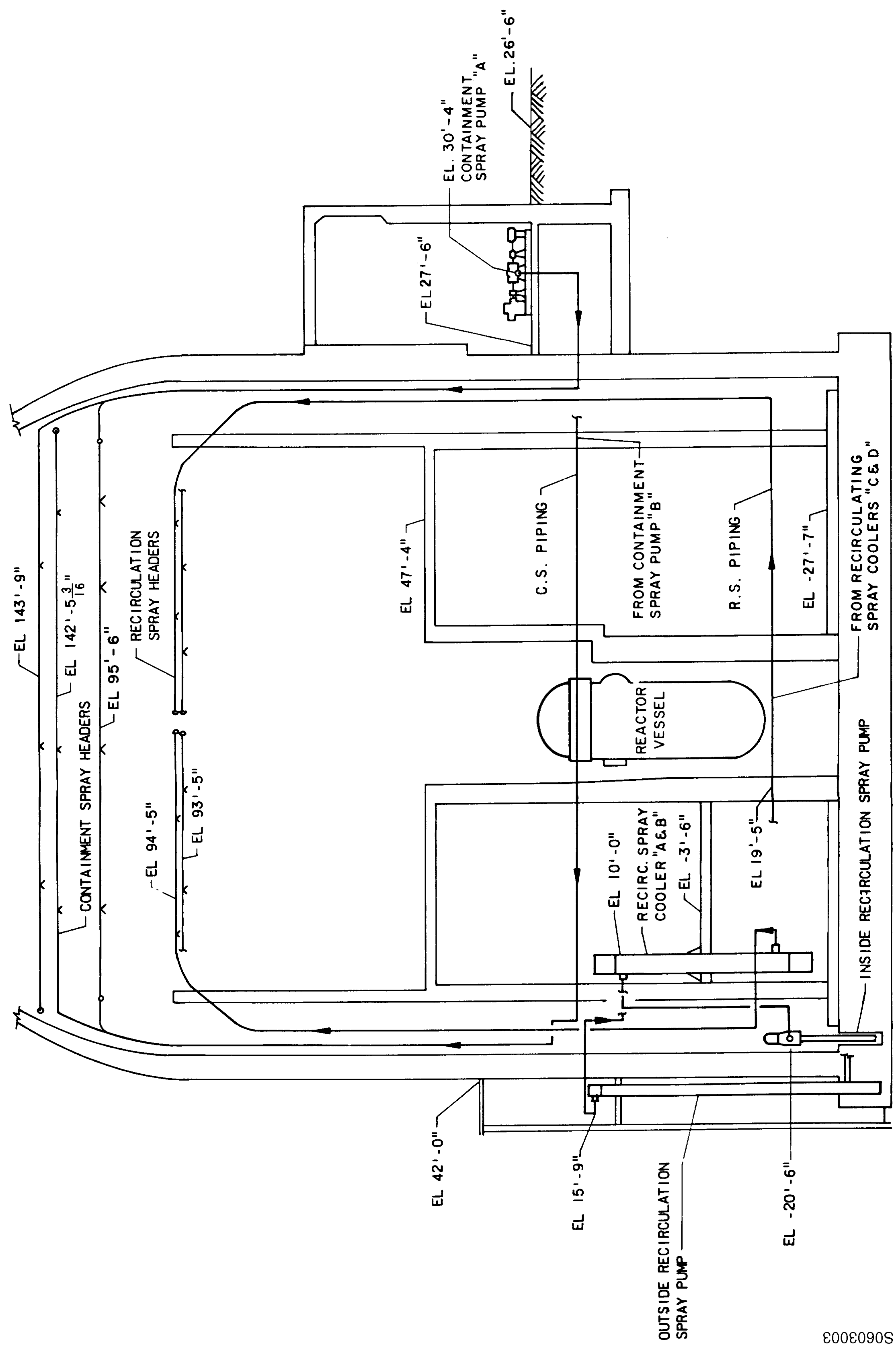
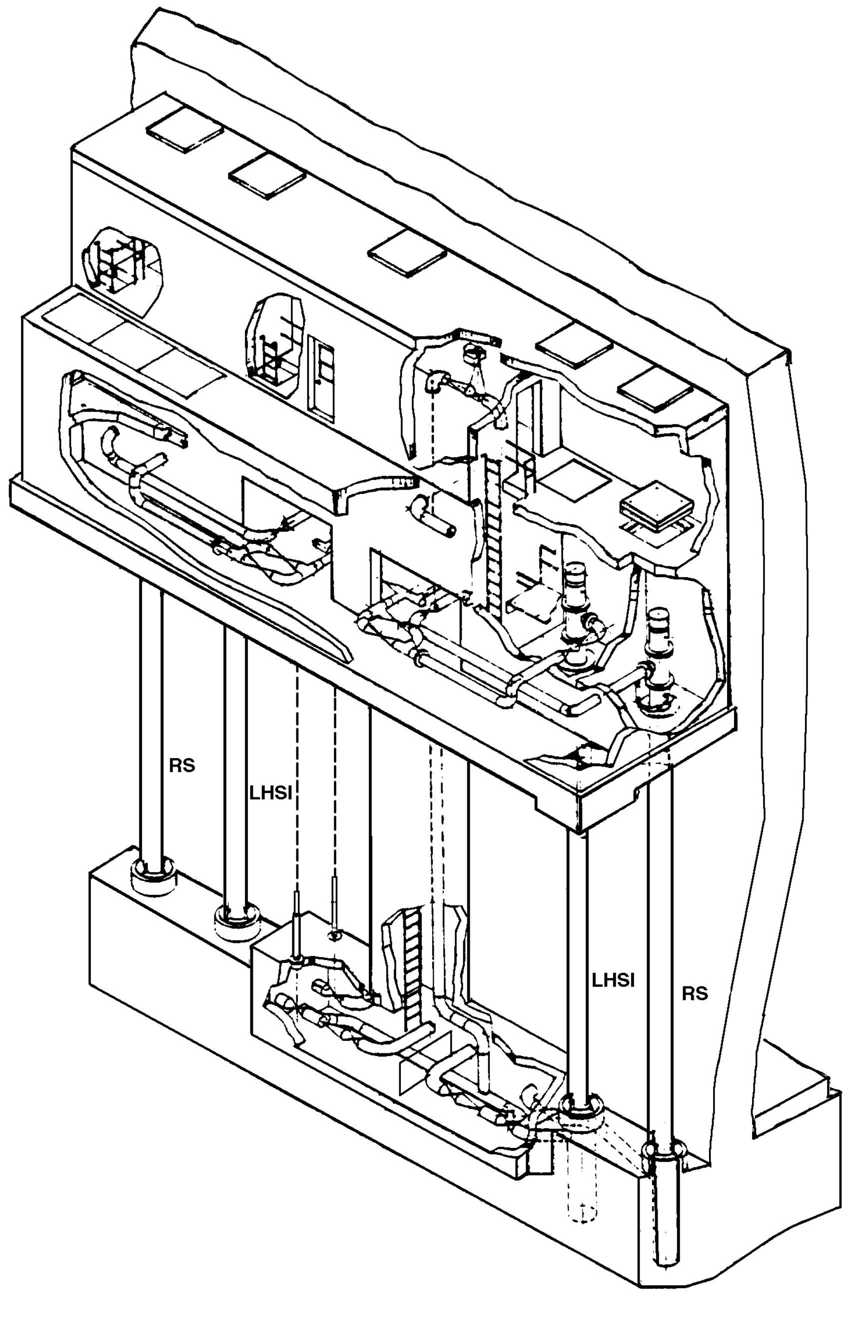


Figure 6.3-5
TYPICAL - GENERAL STRUCTURAL AND PIPING
ARRANGEMENT RECIRCULATION SPRAY AND LOW HEAD SAFETY
INJECTION SYSTEMS OUTSIDE THE REACTOR CONTAINMENT



S0603005

Figure 6.3-6
OUTSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEHLG AT 10.3 PSIA, 25°F SW

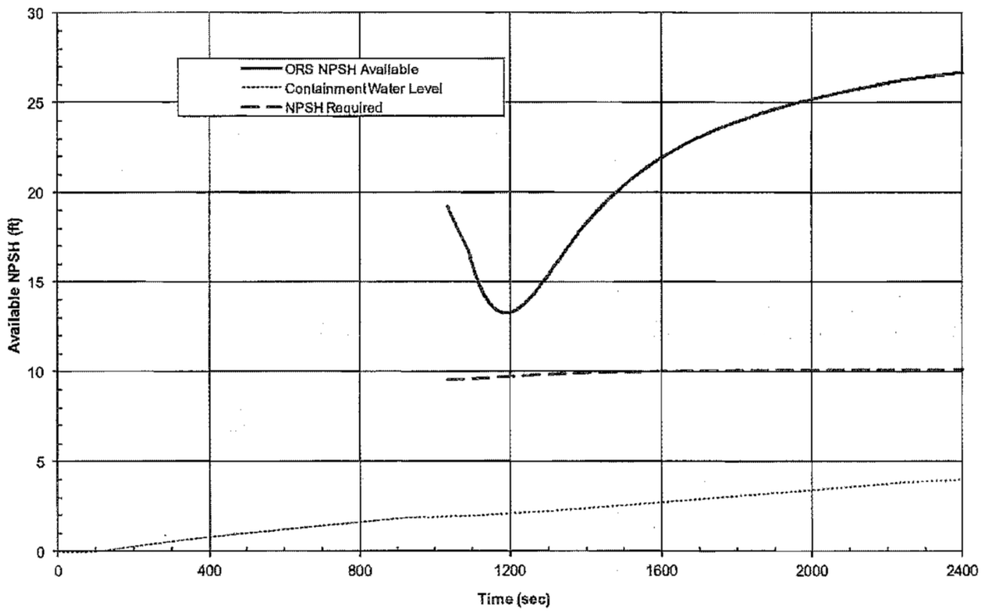


Figure 6.3-7
OUTSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEHLG AT 10.3 PSIA, 25°F SW

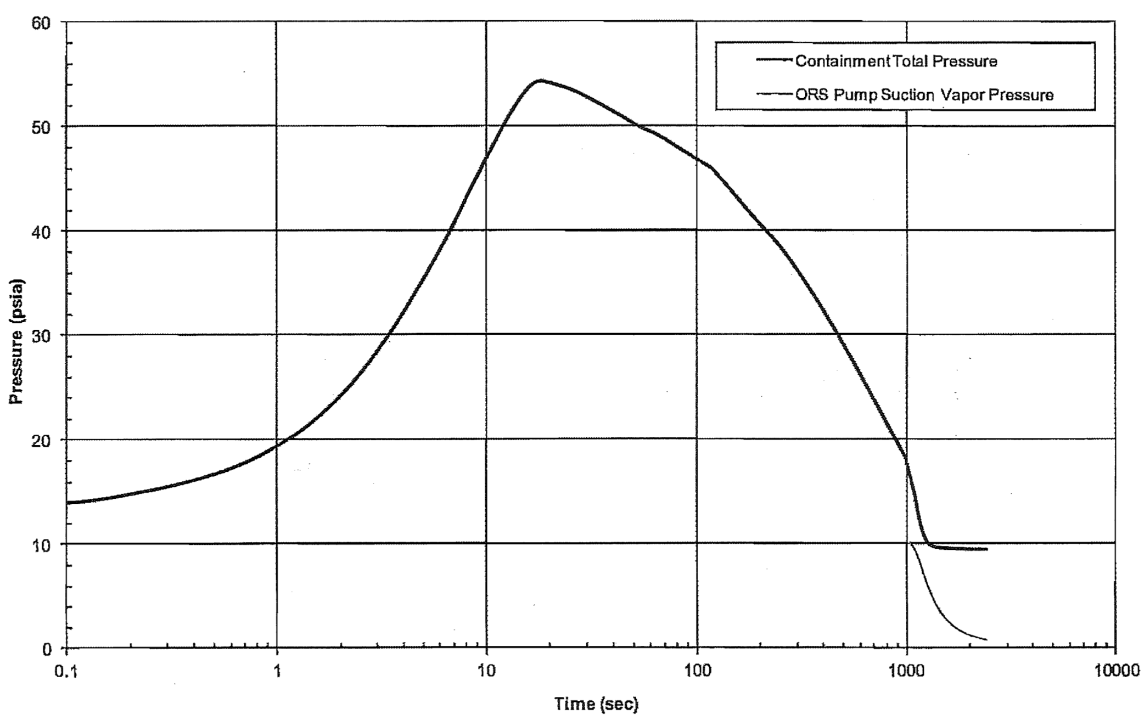


Figure 6.3-8
OUTSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEHLG AT 10.3 PSIA, 25°F SW

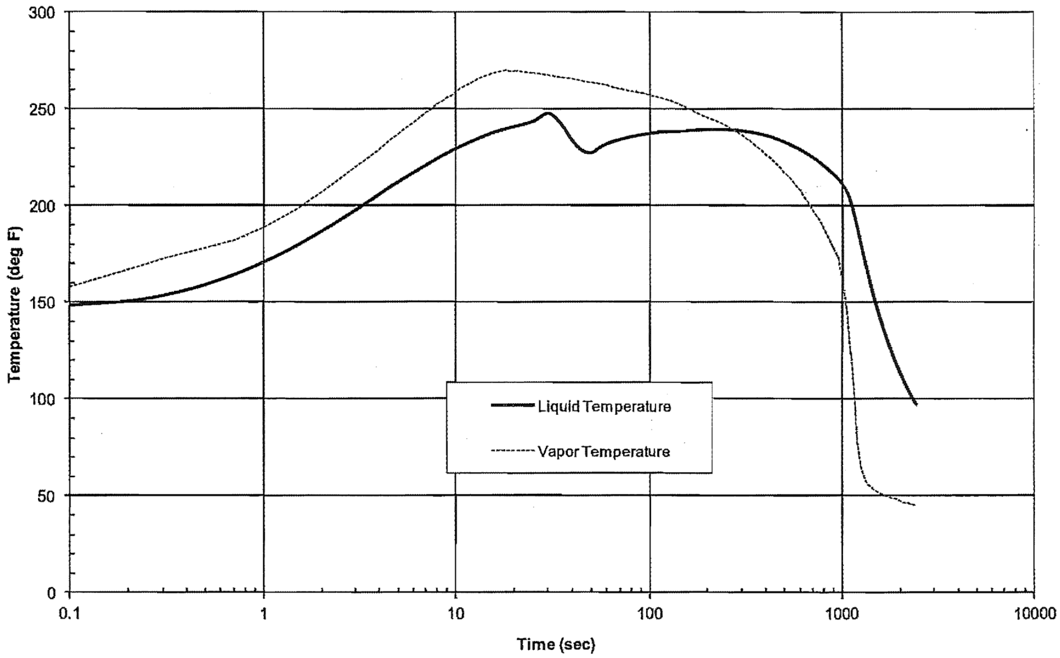


Figure 6.3-9
OUTSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEHLG AT 10.3 PSIA, 25°F SW

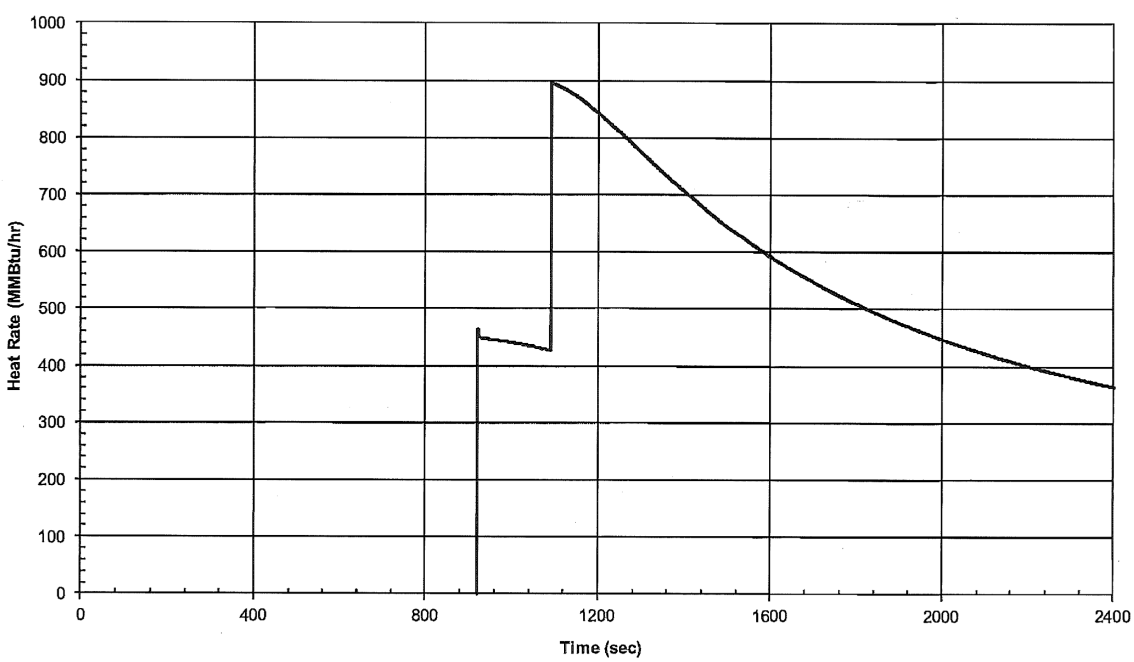


Figure 6.3-10
INSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEPSG AT 10.1 PSIA, 70°F SW

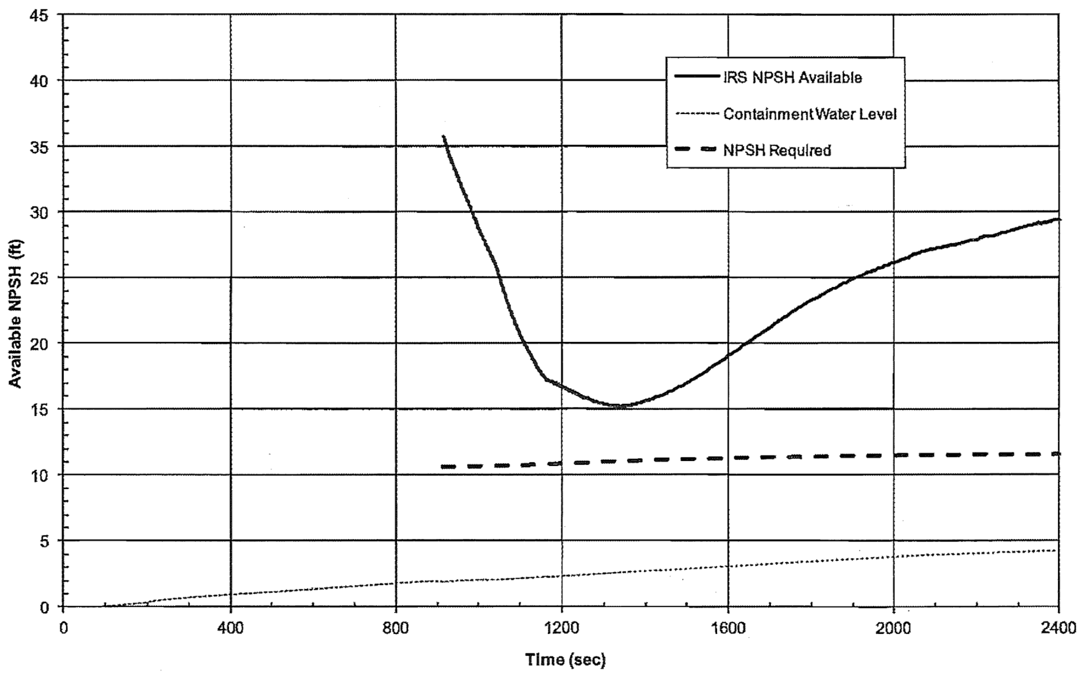


Figure 6.3-11
INSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEPSG AT 10.1 PSIA, 70°F SW

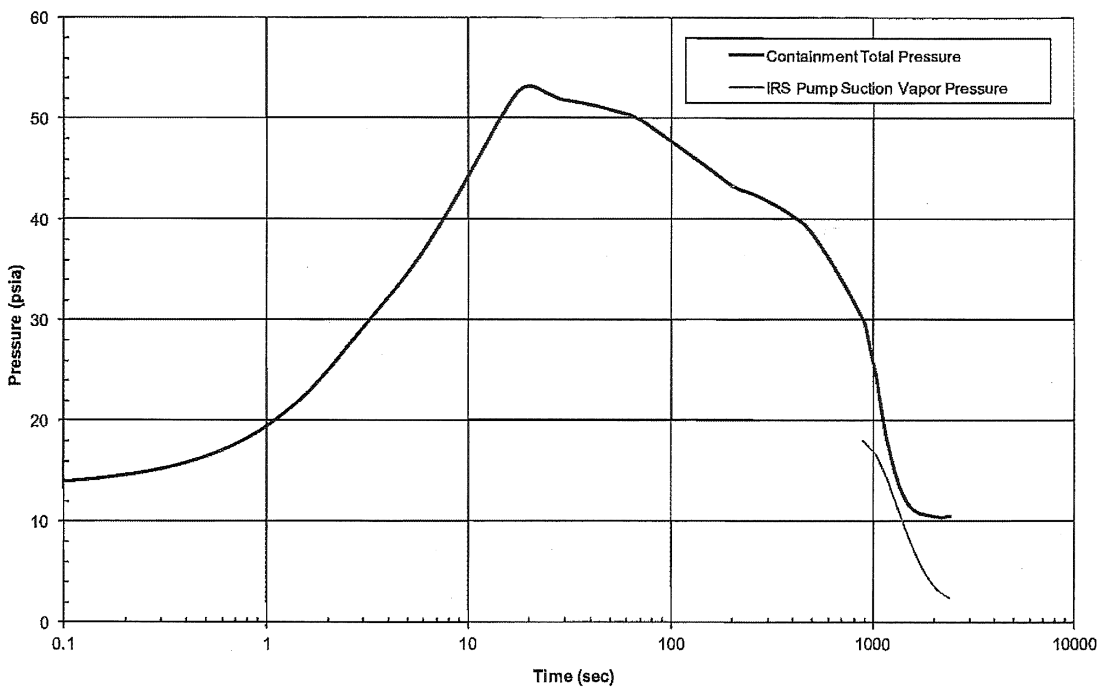


Figure 6.3-12
INSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEPSG AT 10.1 PSIA, 70°F SW

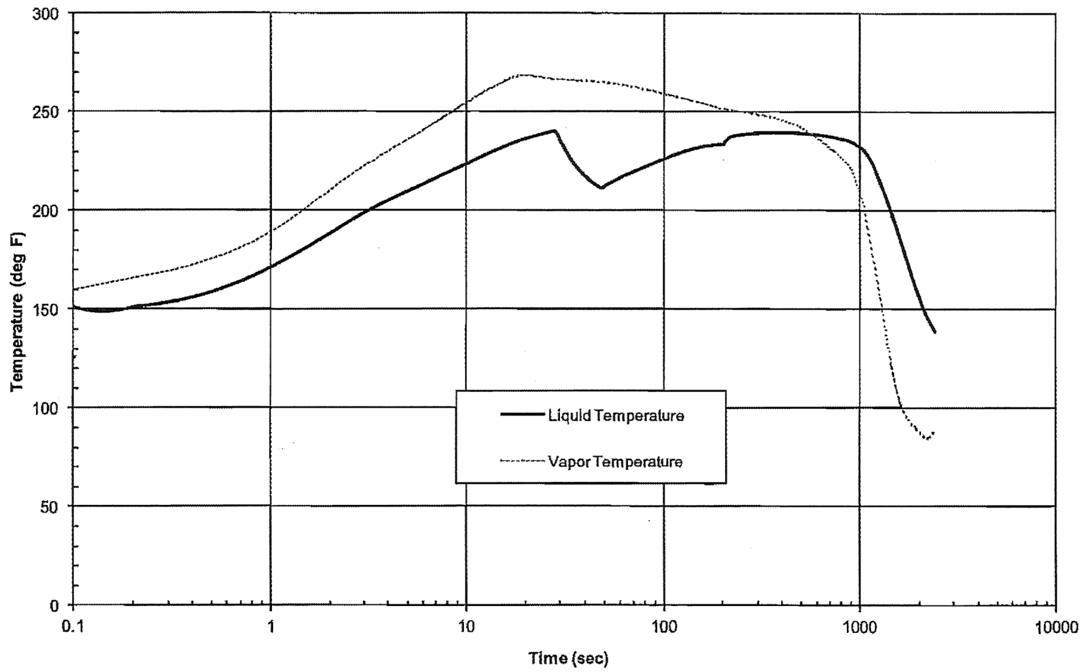
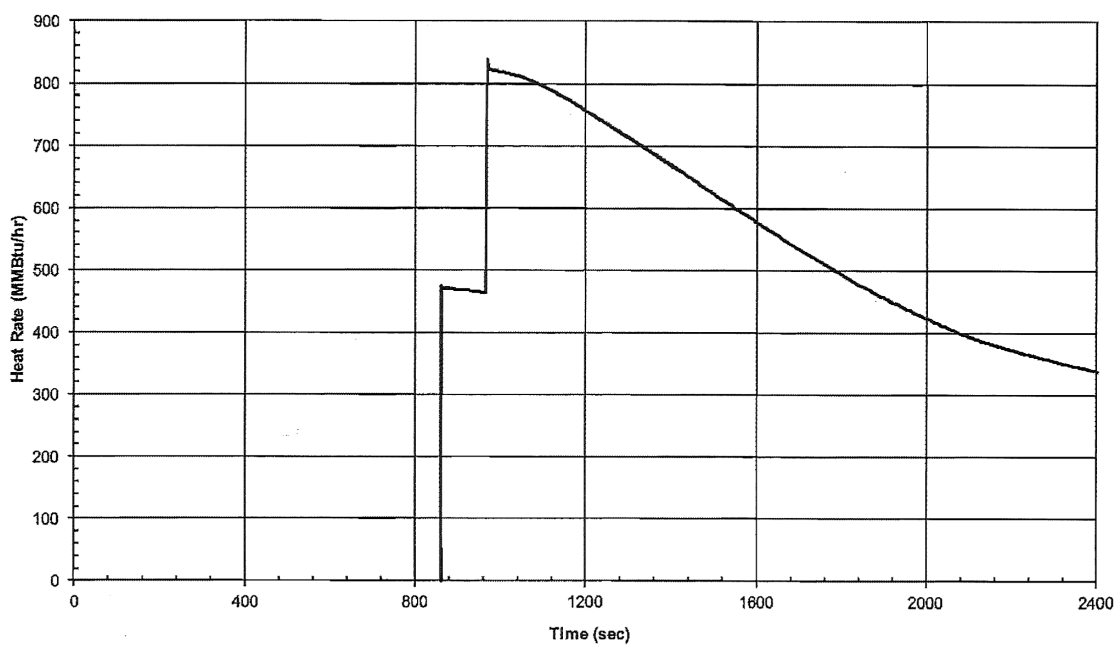


Figure 6.3-13
INSIDE RS PUMP NPSH AVAILABLE ANALYSIS
DEPSG AT 10.1 PSIA, 70°F SW



Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 7

Intentionally Blank

Chapter 7: Instrumentation and Control
Table of Contents

Chapter 7: Instrumentation and Control
Table of Contents (continued)

Chapter 7: Instrumentation and Control
Table of Contents (continued)

Chapter 7: Instrumentation and Control
Table of Contents (continued)

Chapter 7: Instrumentation and Control
Table of Contents (continued)

Chapter 7: Instrumentation and Control

List of Tables

Chapter 7: Instrumentation and Control

List of Figures

Chapter 7: Instrumentation and Control

List of Figures (continued)

Figure	Title	Page

CHAPTER 7 INSTRUMENTATION AND CONTROL

7.1 INTRODUCTION

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

7.1.1 General Design Criteria

Instrumentation and controls are provided to monitor and maintain all operationally important reactor operating parameters such as neutron flux, system pressures, flow rates, temperatures, levels, and control rod positions within prescribed operating ranges.

Process variables which are required on a continuous basis for the start-up, power operation, and shutdown of the unit are indicated in, recorded in, and changed as necessary from the control room, which is a controlled access area. With controlled access, the operating staff is cognizant and in control of all test, maintenance, and calibration work and, knowing the extent to which specific and related operating tasks are in process, the staff can fully assess all abnormal plant conditions.

Criteria for instrumentation wires, cables, trays, and conduits are given in Chapter 8.

Several criteria related to all instrumentation and control systems but more specific to other plant features or systems are discussed in other chapters as listed below:

Criterion	Discussion
Suppression of power oscillations	Chapter 3
Reactor core design	Chapter 3
Quality standards	Chapter 1
Performance standards	Chapter 1
Fire protection	Chapter 9
Missile protection	Chapter 5
Emergency power	Chapter 8

7.1.2 Regulatory Guide 1.97 Program

Regulatory Guide 1.97, *Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident*, contains tables of instrumentation required by the operators to monitor the plant and environs during and following an accident. This instrumentation consists of indicators that are associated with a variety of plant safe-shutdown and balance of plant systems. The intent of Regulatory Guide 1.97 is to provide the operators with the minimum essential information during and following an accident so that they will be able to mitigate and minimize the consequences of the accident. The regulatory guide has specifically determined four of the five types of instrumentation required to ensure proper indication is available to the operators. These four types (Type B, C, D, and E) are outlined in Table 3 of the regulatory guide along with their specifically assigned category, design, and qualification requirements. The fifth type of instrumentation, Type A variables, are plant specific. A Type A variable provides the operator with essential information necessary to take manual actions to mitigate an accident for which no automatic actions are provided. These instruments are characterized by their definition as stated in the regulatory guide. These definitions are:

1. Type A Variables: those variables to be monitored that provide the primary information required to permit the control room operator to take specific manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accident events. Primary information is essential for the direct accomplishment of the specified safety functions; it does not include those variables that are associated with contingency actions that may also be identified in written procedures.

2. Type B Variables: those variables that provide information to indicate whether plant safety functions are being accomplished. Plant safety functions are (1) reactivity control, (2) core cooling, (3) maintaining reactor coolant system integrity, and (4) maintaining containment integrity (including radioactive effluent control). Variables are listed with designated ranges and category for design and qualification requirements. Key variables are indicated by design and qualification Category 1.

3. Type C Variables: those variables that provide information to indicate the potential for being breached or the actual breach of the barriers to fission product releases. The barriers are (1) fuel cladding, (2) primary coolant pressure boundary, and (3) containment.

4. Type D Variables: those variables that provide information to indicate the operation of individual safety systems and other systems important to safety. These variables are to help the operator make appropriate decisions in using the individual systems important to safety in mitigating the consequences of an accident.

5. Type E Variables: those variables to be monitored as required for use in determining the magnitude of the release of radioactive materials and continually assessing such releases.

To further define the variables, Regulatory Guide 1.97 has assigned each variable a design and qualification category. This categorization consists of either a category 1, 2, or 3 designation, with a category 1 having the most stringent requirements, and category 3 having the least stringent. The variables are examined against twelve design and qualification criteria. However, category 2 or 3 variables may be exempt from some or all of the individual criterion's requirements. The criteria and how they are to be applied against each of the three categories are listed in Table 1, *Design and Qualification Criteria for Instrumentation*, of Regulatory Guide 1.97. The twelve category requirements consist of the following:

1. Equipment Qualification
2. Redundancy
3. Power Source
4. Channel Availability
5. Quality Assurance
6. Display and Recording
7. Range
8. Equipment Identification
9. Interfaces
10. Servicing, Testing, and Calibration
11. Human Factors
12. Direct Measurement

In response to NUREG 0737, and Regulatory Guide 1.97, Revision 3, Virginia Power has developed a programmatic approach in defining the Regulatory Guide 1.97 required equipment. The Virginia Power Regulatory Guide 1.97 program reviews examined each of the required instrumentation loops against the category design and qualification requirements. The reviews determined whether equipment upgrades to meet the regulatory guide requirements were required. The required equipment upgrades have been performed to meet the *Design and Qualification Criteria for Instrumentation* of the regulatory guide. Virginia Power has also taken exceptions to the category requirements for certain plant instruments. These exceptions to the regulatory guide have been outlined in correspondence between the NRC and Virginia Power. Virginia Power has developed a plant specific Technical Report, PE-0014, that provides a tabular identification of Regulatory Guide 1.97 instrumentation loops and circuits.

7.1 References

1. Technical Report PE-0014, *Surry Power Station Response to Regulatory Guide 1.97*.

Intentionally Blank

7.2 REACTOR PROTECTION SYSTEM

The reactor protection system and the engineered safeguards comprise the protective systems at the Surry Power Station. The equipment, from sensors to actuating devices, is considered a part of a given protective system.

The design objectives and functional implementation of the reactor protection system (tripping) and the engineered safeguards for the Surry units are the same as for H. B. Robinson Unit 2. The Surry reactor coolant systems have loop stop valves, where the H. B. Robinson unit does not. The presence of loop stop valves necessitates additional protection grade interlocks for the stop valve opening circuits.

As the functional requirements were translated into control equipment during the detailed design of the plant, some minor changes in equipment were made, to:

1. Reduce the amount of equipment required to accomplish a specific control function and, therefore, reduce equipment complexity and maintenance time during plant operation.
2. Modify instrument and control ranges to be consistent with the plant parameters corresponding to the increased power rating for Surry compared to that of the H. B. Robinson design.

Specific functions, however, will be accomplished with the same degree of reliability and redundance as they were in H. B. Robinson design. It should also be noted that the steam dump capacity of the Surry plant is approximately half of that provided for the H. B. Robinson plant, since the Surry plant is designed for a 50% load rejection without trip whereas the H. B. Robinson plant is designed for a 95% load rejection without trip.

All protection grade instrumentation and control systems were designed and procured by Westinghouse Electric Corporation, with the following exceptions: The containment pressure instrumentation and logic, containment spray systems, and diesel generators were in the Stone and Webster scope of supply. Westinghouse process control modules may be replaced with modules manufactured by NUS Scientech.

There are no basic differences between Surry and H. B. Robinson with respect to protection grade instrumentation and control systems because both plants are designed in accordance with the criteria established in IEEE-279 and objectives of the General Design Criteria.

Design criteria for the Surry protective systems were chosen to permit maximum effective use of process measurements both for control and protection functions, thus enhancing the capability to provide an adequate system to deal with the majority of common-mode failures as well as to provide redundancy for critical control functions. This design approach provides protective systems that monitor numerous system variables by different means, i.e., protective system diversity. Such diversity has been evaluated for a wide variety of postulated accidents (Reference 1).

Reactor protection system and engineered safety features equipment are identified as safety-related equipment by several means. The electrical cables to vital instruments and control and electrical components are color coded to identify them as vital circuits. Vital circuits are divided into three main categories:

1. The 4160V and 480V ac and 125V dc circuits fed to or from the emergency buses 1H and 2H are color-coded “orange.”
2. The 4160V and 480V ac and 125V dc circuits fed to or from the emergency buses 1J and 2J are color-coded “purple.”
3. The circuits for the four protection instrument channels are identified by red, white, blue, and yellow color coding.

In addition, colored nameplates are affixed to vital instruments and equipment used in operation. These components include air circuit breakers, panels, switchgear, voltmeters, ammeters, control switches, and other associated equipment.

The remainder of Section 7.2 is primarily concerned with the reactor protection system, although some information may also apply to the engineered safeguards. Detailed discussion of the engineered safeguards can be found in Section 7.5.

7.2.1 Design Bases

The reactor protection system and the engineered safeguards are designed in accordance with IEEE-279 *Standard, Nuclear Power Plant Protection Systems,* August 1968. Detailed descriptions of the implementation of these principles are presented in the remainder of Section 7.2 and in Sections 7.4 and 7.5.

7.2.1.1 **Control Room**

Each unit is equipped with a control room which contains those controls and instruments necessary for operation of the reactor and turbine generator under normal and accident conditions.

The control room is continuously occupied by qualified operating personnel under all operating and design-basis accident (DBA) conditions.

Sufficient shielding, distance, and containment integrity are provided to ensure that under postulated accident conditions during occupancy of the control room, control room personnel shall not be subjected to doses that, in the aggregate, would exceed the limits in 10 CFR 50, Appendix A, GDC 19. The control room ventilation consists of a system having a large percentage of recirculated air. The fresh air intake can be closed to stop the intake of airborne activity if monitors indicate that such action is appropriate.

7.2.1.2 **Core Protection Sequence**

If the reactor protection system receives signals which indicate an approach to unsafe operating conditions, the system actuates alarms, prevents control rod withdrawal, initiates load runback, and/or opens the reactor trip breakers.

The basic reactor operating philosophy is to define an allowable region of power, pressure, and coolant temperature conditions. This allowable range is defined by primary tripping functions, which include the overpower delta T trip, the overtemperature delta T trip, and the nuclear overpower trip. The operating region below these trip settings is designed so that no combination of power, temperature, and pressure could result in a departure from nucleate boiling ratio (DNBR) less than the design DNBR limit (Section 3.2.3) for any credible operational transient with all reactor coolant pumps in operation. Tripping functions in addition to the primary tripping functions stated above are provided to back up the primary tripping functions for specific abnormal conditions. A complete list of tripping functions is given in Table 7.2-1.

The dropped control rod is indicated by the rod position flat panel displays and by a rapid flux decrease on any of the power range nuclear channels.

Rod stops from nuclear overpower, overpower delta T, and overtemperature delta T deviation are provided to prevent abnormal power conditions, which could result from excessive control rod withdrawal initiated by operator violation of administrative procedures. The automatic rod withdrawal function of the reactor control system is disabled such that no control system malfunctions will result in excessive control rod withdrawal.

7.2.1.3 **Reliability, Redundancy, and Independence**

Protection and operation reliability is achieved in part by providing redundant instrumentation channels for each protective function. These redundant channels are electrically isolated and physically separated. The channel design incorporates separate sensors, separate power supplies, separate rack-mounted and panel-mounted equipment, and separate relays for the actuation of the protective function. For protective functions where two-out-of-three or two-out-of-four redundant-coincident actuation is provided, a single channel failure will not impair the protective function nor will it cause an unnecessary unit shutdown.

Reactor protection system channels are designed with sufficient redundancy for individual channel calibration and testing to be performed during power operation without degrading reactor protection. Bypass removal of one trip channel is accomplished by placing that channel in a partial-trip mode. For example, a two-out-of-three channel becomes a one-out-of-two channel. Testing will not cause a trip unless a trip condition exists concurrently in another channel.

The reactor protection system is designed so that the most probable modes of failure in each channel result in a reactor trip signal. The protection system design combines redundant sensors and channel independence with coincident trip philosophy so that a safe and reliable system is provided in which a single failure will not defeat the channel function, cause a spurious trip, or violate reactor protection criteria.

In the Westinghouse control and protection system, the control system is separate and distinct from the protection system. Although the protection system is independent of the control system, the control system is dependent upon signals derived from the protection system through isolation amplifiers. The design approach is to use fully and thereby most efficiently, for both control and protection purposes, measurements of unit variables. Little additional safety is achieved by using independent but identical measurements for control and protection.

This approach permits all equipment to be identified for protection or control and to be grouped accordingly, electrically isolated, and physically separated. In this way there is control redundancy, providing a significant increase in overall unit safety and also a protection system continuously monitoring a large number of system variables by different means. That is, there is protection system diversity.

In the reactor protection system, two reactor trip breakers are provided to interrupt power to the control rod assembly drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all control rod assembly drive mechanisms and permits the control rod assemblies to free fall into the core.

A bypass breaker is also provided for each reactor trip breaker. It should be noted that administrative controls alone are not relied upon to prevent simultaneous closure of both reactor trip bypass breakers. When either reactor trip bypass breaker is placed in the operate position, an alarm and annunciator is actuated in the control room. Also, closing one reactor trip bypass breaker when both breakers are in the operate position will generate a trip signal for the other reactor trip bypass breaker.

The components of the protection system are designed and arranged so that, even with an adverse environment accompanying an emergency situation, the components will function as required without interference.

Separation of redundant analog protection channels originates at the process sensors and continues through the wiring route and containment penetrations to the analog protection racks. Physical separation is used to the maximum practical extent to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating components in different protection racks. Each redundant channel is energized from a separate instrument bus.

Further detail on redundancy is provided by the descriptions of the respective systems covered by Section 7.2.2. Required continuous power supply for the protection systems is discussed in Chapter 8.

7.2.1.4 **Reactivity Control**

One of the two reactivity control systems employs control rod assemblies to regulate the position of the neutron absorbers within the reactor core (Chapter 3). The other reactivity control system employs the chemical and volume control system (Chapter 9) to regulate the concentration of boric acid solution neutron absorber in the reactor coolant system.

Reactor shutdown by control rod assemblies is completely independent of the normal control functions, since the trip breakers interrupt the power to the control rod mechanisms regardless of existing control signals. Effects of continuous withdrawal of a control rod assembly and of de-boration are described in Chapter 14.

7.2.1.5 **Manual Actuation**

Means are provided for manual initiation of protective system action. Failure in the automatic system does not prevent the manual actuation of protective functions. Manual actuation is designed to require the operation of a minimum amount of equipment.

7.2.1.6 **Channel Bypass**

The system is designed to permit any one channel to be maintained, tested, or calibrated during power operation without system trip. During such operation the active parts of the system continue to meet the single-failure criterion, since the channel under test is either tripped or makes use of superimposed test signals that do not negate the process signal.

"One-out-of-two" systems are permitted to violate the single-failure criterion during channel bypass provided that acceptable reliability of operation can be otherwise demonstrated and the bypass time interval is short.

7.2.1.7 **Calibration and Testing**

The bi-stable portions of the protective system (e.g., relays, bi-stables, etc.) provide trip signals only after signals from analog portions of the system reach preset values. Capability is provided for calibrating and testing the performance of the bi-stable portion of protective channels and various combinations of the logic networks during reactor operation.

The analog portion of a protective channel (e.g., sensor and amplifier) provides an analog signal of the reactor or unit parameter. The following methods for checking the analog portion of a protective channel during reactor operation are provided:

1. Varying the monitored parameter.
2. Introducing and varying a substitute transmitter signal.
3. Cross-checking between identical channels or between channels that bear a known relationship to each other and that have readouts available.

The design provides for administrative control in order to manually bypass channels for test and calibration purposes.

The design provides for administrative control of access to all trip settings, module calibration adjustments, test points, and signal injection points.

The signal-conditioning equipment of each protection channel in service at power is capable of being calibrated and tested independently by simulated analog input signals to verify its operation without tripping the reactor. The testing scheme includes checking through the trip logic to the trip breakers. Thus, the operability of each trip channel can be determined conveniently and without ambiguity. Functional operation of the power sources for the protection system is discussed in Chapter 8.

7.2.1.8 **Functional Requirements**

The reactor protection system in conjunction with inherent plant characteristics is designed to prevent anticipated abnormal conditions from exceeding limits established in Chapters 3 and 4.

7.2.1.8.1 Completion of Protective Action (Interlock)

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are part of the protective system and are designed in accordance with the criteria of this section.

The protective systems are so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

7.2.1.8.2 Multiple Trip Settings

For monitoring neutron flux, multiple trip settings are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system as designed provides positive assurance that the more restrictive trip setting is used. The devices used to prevent improper use of less restrictive trip settings are considered a part of the protective system and are designed in accordance with the criteria presented in this section.

7.2.1.8.3 Protective Actions

The reactor protection system automatically trips the reactor when the conditions listed in Table 7.2-1 exist.

Interlocking functions of the reactor protection system prevent control rod withdrawal when a specified parameter reaches a specified value that is less than the value at which a reactor trip is initiated. The automatic rod withdrawal function of the reactor control system is disable. The interlocking functions continue to block manual rod withdrawal.

For anticipated abnormal conditions, protective systems in conjunction with inherent characteristics and engineered safeguards are designed to ensure that limits for energy release to the containment and offsite radiation exposure (as in 10 CFR 50.67 or Regulatory Guide 1.183) are not exceeded.

Each reactor trip channel is designed on the “de-energize to operate” principle; an open channel or a loss of power causes that channel to go into its trip mode.

Reactor trip is implemented by simultaneously interrupting power to the magnetic latch mechanisms on each control rod drive, so that the control rod assemblies insert by free-fall. The entire protection system is thus inherently safe in the event of a loss of power.

7.2.1.8.4 Indication, Alarms, and Annunciators

All transmitted signals (flow, pressure, temperature, etc.) that can lead to a reactor trip are either indicated or recorded for every channel.

All neutron flux power range currents (top detector, bottom detector, and algebraic difference and average of bottom and top detector currents) are indicated and/or recorded.

The protective system provides the operator with complete information pertinent to system status and safety.

Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

Trips are indicated and identified down to the channel level.

Alarms and annunciators are also used to alert the operator of deviations from normal operating conditions so that he may take corrective action to avoid a reactor trip. Further, actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

7.2.1.8.5 Operating Environment

The protective channels are designed to perform their function when subjected to adverse environmental conditions. See Section 7.5 for the criteria for those portions of the protective systems that must operate in a post-accident environment.

7.2.1.8.6 Seismic Design

Reactor protection system equipment is designed to ensure that it does not lose its capability to perform its function during an operating-basis earthquake or a design-basis earthquake, i.e., the equipment will shut the plant down and maintain it in a safe shutdown condition.

For the design-basis earthquake, there may be permanent deformation of the equipment provided that the capability to perform its function is maintained.

Typical protection system equipment is subjected to type tests under simulated seismic accelerations to demonstrate its ability to perform its functions. Type testing is done by using conservatively large accelerations and applicable frequencies. Analyses done for structures are not done for the reactor protection system equipment; however, the peak accelerations and frequencies are checked against those derived by structural analyses of operating-basis earthquake and design-basis earthquake loadings.

A Westinghouse topical report, WCAP-7397-L, provides the original seismic evaluation of safety-related equipment. The type tests covered by this report are applicable to the Surry Station with the exception of the process control equipment, which is covered in a supplement to WCAP-7397-L. Non-Westinghouse replacement modules have been seismically tested and are seismically qualified.

The control board is designed to withstand earthquake conditions, and an analysis was performed to verify the adequacy of the seismic design. Tests were not performed.

7.2.2 System Description

The reactor protection system provides the means for controlling the reactor in response to various measured primary and secondary variables associated with power, temperature, pressure, level, flow, and the availability of electric power. If the combination of monitored variables indicates an approach to unsafe conditions, the reactor protection system will initiate the appropriate protective action, e.g., load runback, prevention of rod withdrawal, or reactor trip (opening the reactor trip breakers).

Figure 7.2-1 illustrates typical core limits and shows the maximum trip points which are used for the protection system. The solid lines indicate a typical locus of DNBR equal to the design DNBR limit (Section 3.2.3) at four pressures, and the dashed lines indicate maximum permissible trip points for the overtemperature delta T reactor trip. Actual setpoints (the safety limits are given in the Technical Specifications) are lower to allow for measurement and instrumentation errors. The overpower delta T reactor trip limits the maximum core power independent of the DNBR.

Adequate margins exist between the nominal steady-state operating point and required trip points to preclude a spurious trip during design transients.

A block diagram of the reactor protection system showing various reactor trip functions and interlocks is shown in Figure 7.2-2. A logic diagram for the low-reactor-coolant-flow trips is shown in Figure 7.2-3.

7.2.2.1 **System Safety Features**

7.2.2.1.1 Separation of Redundant Protection Channels

The reactor protection system is designed to achieve separation between redundant protection channels. The channel design is applied to the analog and the logic portions of the protection system and is illustrated by Figure 7.2-4. Although the illustration is for four-channel redundancy, the design is applicable to two-channel and three-channel redundancy.

Separation of redundant analog channels originates at the process sensors and continues along the wiring route and through containment penetrations to the analog protection racks. Isolation of wiring is achieved by using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Analog equipment is separated by locating redundant components in different protection racks. Each redundant channel is energized from a separate ac power feed. Logic equipment separation is achieved by providing separate racks, each associated with individual trip breakers.

Cables have been installed in accordance with VEPCO specification, *Criteria for Installation and Identification of Electrical Cables.*

Cables pertaining to reactor protection and engineered safety features are installed so that redundant circuits are separated and this separation is readily identified. Separation of redundant circuits is obtained by one of the following:

1. Rigid metal conduit (following separate routes).
2. Horizontal separation of horizontal cable trays without barriers.
3. Vertical separation of horizontal cable trays by means of barriers or tray covers (redundant channels are not combined in one tray or conduit).

A color-coded system is provided to identify individual safety channels, and additional colors are used to identify redundant safety trains. The color-coding scheme is an aid to both the installer of cable and the inspector.

1. Power cables and control cables are separated. Where possible, power cables are not installed in the same tray with control cables. Where it is necessary to install power cables in the same tray with control cables, a distance of at least 1/4 diameter of the power cable is maintained between the power and control cables. For safety circuits, where power and control cables are in the same tray, the power cable is contained in interlocked armor. Power cable is defined as any cable carrying 60A or supplying a 30-hp or larger motor. All power cables in trays are installed only one layer deep.
2. Control and instrument cables are usually run in separate trays; however, there are some areas where control and non-sensitive instrumentation cables are run in the same tray.
3. Cables from redundant protection channels or trains are never intermixed within a tray.

4. Non-vital cables such as annunciator, computer, or instrument cables may be routed with the protection system cables; however, they are separated wherever practical.

The cables to the penetrations in the cable tunnel and vaults are routed in two separate cable runs. There is a total of 90 penetrations, 5 rows high by 18 rows long.

The penetrations are arranged so that power, control, and instrumentation cables are separated from each other within a train and the two trains are never intermixed. The minimum distance between redundant services is never less than 2 feet at the penetrations.

Cable de-rating factors are in accordance with standards of the Insulated Power Cable Engineers' Association. Power cables 60A and over are rated and sized for 90°C operation. The sizing of power cables includes service factor where applicable, de-rating factors for maintained cable spacing of 1/4 diameter, and fire stops, if used. Where power cable spacing is less than 1/4 diameter (maintained), the power cables are treated as random filled and de-rated with base ampacities using applicable industry standards.

Control cables may be installed in cable trays in a random manner up to 80% of tray capacity, computed using the cross-sectional area of the cable. Control cables must meet one of the following conditions:

1. No appreciable conductor I^2R heating loss (interlocks, indicating lamps, controls, etc.).
2. Intermittent duty (valve operators).
3. Cable for continuous operation must use a derating factor of 50%-maximum continuous operation 60A or 30 hp - maximum wire size No. 4 AWG copper.

Instrument cables are installed in trays in a random manner up to 80% of tray capacity, computed by using the cross-sectional area of the cable, without derating. The protection of cables is either by protective relays or circuit breakers that are individually selected for each circuit.

Smoke detectors and carbon dioxide protection are provided in non-occupied areas of cable runs, such as cable tray rooms and cable tunnels. The cable purchased will not propagate fire, and sleeves are sealed after installation of cables. Additional horizontal and vertical fire stops are provided where required. No temperature monitoring of cables is provided. Each cable and wireway is permanently identified with markers.

The criteria for location and routing of instrument lines and transmitters were similar to the criteria established for electrical cables run between the transmitters and penetrations. For example, redundant transmitters and sensing lines are separated, and redundant devices are separated by a minimum of 2 feet, or additional protection is provided.

In reference to Reference Drawings 1 and 2, all cables from the Unit 1 reactor containment pass through a common vault area. Two protection channels and one train are routed on one side of the vault separated by metal tray covers, and the redundant channels and train are routed in a similar manner on the other side. This area is free from combustible materials, potential missile-generating devices, and is protected by fire detection equipment and a carbon dioxide deluge system. Unit 2 is completely isolated from Unit 1.

The reactor trip bi-stables are mounted in the analog protection racks and are the final operational component in an analog protection channel.

Each bi-stable drives logic relays “C” and “D” as shown on Figure 7.2-4. The contacts from the “C” relays are interconnected to form the required actuation logic for trip breaker 1. The transition from channel identity to logic identity is made at the logic relay coil/relay contact interface. As such, there is both electrical and physical separation between the analog and the logic portions of the protection system. The above logic network is duplicated from trip breaker 2 by using the contacts from the “D” relays. Therefore, the two redundant reactor trip logic channels will be physically separated and electrically isolated from one another. The reactor protection system consists of identifiable channels that are physically, electrically, and functionally separated and isolated from one another.

7.2.2.1.2 Loss of Power

A loss of power in the reactor protection system causes the affected channel to trip. All bi-stables operate in a normally energized state and go to a de-energized state to initiate action.

7.2.2.1.3 Reactor Trip Signal Testing

Provisions are made, for process variables, to manually place the output of the bi-stable in a tripped condition for “at power” testing of all portions of each trip circuit including the reactor trip breakers. Administrative procedures require that the final element in a trip channel (required during power operation) be placed in the trip mode before that channel is taken out of service for repair or testing so that the single-failure criterion is met by the remaining channels. In the source and intermediate ranges where the trip logic is one out of two for each range, bypasses are provided for this testing procedure.

Nuclear instrument power range channels are tested by superimposing a test signal on the sensor signal so that the reactor trip protection is not bypassed. Based upon coincident logic (two-out-of-four) this will not trip the reactor.

Provision is made for the insertion of test signals in each analog loop. Verification of the test signal is made by portable instruments at test points specifically provided for this purpose. This enables testing and calibration of meters and bi-stables. Transmitters and sensors are checked against each other and against precision readout equipment when required during normal power operation.

7.2.2.1.4 Process Analog Protection Channel Testing

The basic arrangement of elements comprising a representative analog protection channel is shown in Figure 7.2-5. These elements include a sensor or transmitter, power supply, bi-stable, bi-stable trip switch and proving lamp, test-operate switch, test annunciator, test signal injection jack, and test points. A portion of the logic system is also included to illustrate the overlap between the typical analog channel and the corresponding logic circuits. The analog system symbols are given in Table 7.2-2.

Each protection rack includes a test panel containing those switches, test jacks, and related equipment needed to test the channels contained in the rack. An interlocked, hinged cover encloses the test panel. Opening the cover or placing the test-operate switch in the TEST position automatically initiates an alarm. The test panel cover is designed in such a way that it cannot be closed (and the alarm cleared) unless the test signal plugs (described below) are removed. Closing the test panel cover mechanically returns the test switches to the OPERATE position.

Test procedures require the bi-stable output relays of the channel under test to be placed in the tripped mode before proceeding with the analog channel tests. Thus, for the channel under test, the relay elements in the two-out-of-three or the two-out-of-four coincident matrices are in the tripped mode during the entire test of that channel. This ensures that the remaining channels of the two-out-of-three or the two-out-of-four protective functions meet the single-failure criterion during the entire channel test. Placing the bi-stable trip switch in the tripped mode de-energizes (trips) the bi-stable output relays and connects a proving lamp to the bi-stable output circuit. This permits the electrical operation of the solid-state bi-stable to be observed and the bi-stable setpoint relative to the channel analog signal to be verified. Upon completion of the test of the analog channel, the bi-stable trip switches must be manually reset to their operate mode. Closing the cover of the test panel does not transfer the bi-stable trip switches from their tripped to their operate position.

Analog channel tests are accomplished by simulating a process measurement signal, varying the simulated signal over its signal span, and checking the correlation of bi-stable setpoints, channel readouts, and other loop elements with precision portable readout equipment. Test jacks are provided in the test panel for injection of the simulated process signal into each process analog protection channel. Test points are provided in the channel to facilitate an independent means for precision measurement and correlation of the test signal. With the exception of temperature loops that are monitored by special provisions, this procedure does not require any tools nor does it involve in any way the removal or disconnection of wires in the channel under test. In general, the analog channel circuits are arranged so the channel power supply is loaded and provides sensing circuit power during channel test. Load capability of the channel power supply is thereby verified by the channel test.

7.2.2.1.5 Nuclear Instrumentation Channel Testing

Nuclear instrumentation system channels are tested by superimposing the test signal on the actual detector signal being received by the channel. The output of the bi-stable is not placed in a tripped condition before testing. A valid trip signal would then be added to the existing test signal and thereby cause channel trip at a somewhat lower percent of actual reactor power. Protection bi-stable operation is tested by increasing the test signal (level signal) to the bi-stable trip level and verifying operation at control board alarms and/or at the nuclear instrumentation racks.

A nuclear instrumentation channel that can cause a reactor trip through one-out-of-two protection logic (source or intermediate range) is provided with a bypass function that prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. The power range channels do not require bypass of the reactor trip function for test, since the protection logic is two out of four. The power range dropped-rod alarm is activated from a one-out-of-four logic. The channel test condition is alarmed on the nuclear instrumentation drawer and at the main control board. Administrative control is required to ensure that only one protection channel is placed in the bypass condition at any one time. The power range reactor trips are not affected by the test function described above. Therefore these power range trips are active if required. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the nuclear instrumentation detector.

7.2.2.1.6 Logic Channel Testing

The general design features of the logic system are described below. The trip logic channels for typical two-out-of-three and two-out-of-four trip functions are shown in Figure 7.2-6. The analog portions of these channels are shown in Figure 7.2-7. Each bi-stable drives two relays, one for each train. Contacts from the “A” and “C” relays are arranged in a two-out-of-three and two-out-of-four trip matrix for trip breaker 1.

The above configuration is duplicated for trip breaker 2 by using contacts from the “B” and “D” relays. A series configuration is used for the trip breakers, since they are actuated (opened) by undervoltage coils. This approach is consistent with a de-energize-to-trip preferred failure mode. The planned logic system testing includes exercising the reactor trip breakers to demonstrate system integrity. Bypass breakers are provided for this purpose. During normal operation, these bypass breakers are open. Administrative control will be used to minimize the amount of time these breakers are closed and to prevent simultaneous closure of both bypass breakers. Indication of a closed condition of either bypass breaker is provided locally and on the test panel, and on the control room bench board.

As is shown in Figure 7.2-6, the trip signal from the logic network is simultaneously applied to the main trip breaker associated with the specific logic chain as well as the bypass breaker associated with the alternate trip breaker. Should a valid trip signal occur while bypass breaker AB-1 is bypassing trip breaker TB-1, trip breaker TB-2 will be opened through its associated logic train. The trip signal applied to TB-2 is simultaneously applied to AB-1, thereby opening the bypass around TB-l. Trip breaker TB-l would have either been opened manually as part of the test, or it would be opened through its associated logic train, which would be operational (or tripped) during a test.

An auxiliary relay is located in parallel with the undervoltage coils of the trip breakers. This relay is connected to a test panel mounted white test lamp. The test lamp is used to indicate transmission of a trip signal through the logic network during testing. Lights are also provided to indicate the status of the logic relays.

The following procedure illustrates the method used for testing TB-l and its associated logic network:

1. From the Train B test panel, close bypass breaker AB-1 with the breaker pushbutton, then trip AB-1 from the test panel and visually verify operation. Should AB-1 fail to open, then immediately trip AB-1 with the local trip pushbutton.
2. Close AB-1 from the Train B test panel and make test connections for timing of TB-1.
3. At the trip breaker cubicle, push and hold the “Auto Shunt Trip Block” pushbutton for the TB-1 Breaker.
4. Push the “Auto Shunt Trip Test” pushbutton for TB-1 and verify TB-1 does not trip.
5. Release the “Auto Shunt Trip Test” pushbutton only and sequentially de-energize the trip relays (A1, A2, A3) for the logic combination (1-2, 1-3, 2-3). Verify that the logic network de-energizes the undervoltage coil on TB-l for each logic combination. Verify TB-1 opens by observing breaker position lamps at the test panel and record TB-1 elapsed time.
6. Release the “Auto Shunt Trip Block” pushbutton.
7. For the remaining logic combinations, sequentially de-energize the trip relays (A1, A2, A3) and verify that the logic network de-energizes the undervoltage coil on TB-l (by observing the UV status lamp) for each logic combination.
8. Close TB-1 from the control room benchboard.
9. Depress the “Auto Shunt Trip Test” pushbutton for the “A” reactor trip breaker momentarily and verify TB-1 trips.
10. Remove all test connections and close TB-1 from the benchboard.
11. Open bypass AB-1 from the Train B test panel.

In order to minimize the possibility of operational errors (such as tripping the reactor inadvertently or only partially checking all logic combinations), each logic network includes a logic channel test panel. This panel includes those switches, lights, and pushbuttons needed to perform the logic system tests. This arrangement is illustrated in Figure 7.2-8. The test switches used to de-energize the trip bi-stable relays operate through interposing relays as shown in Figures 7.2-5 and 7.2-7. This approach avoids violating the separation philosophy used in the analog channel design. Thus, although test switches for redundant channels are conveniently grouped on a single panel to facilitate testing, physical and electrical separation of redundant protection channels are maintained by the inclusion of the interposing relay, which is actuated by the logic test switches.

Modifications to the reactor trip switchgear were implemented to satisfy action items in NRC Generic Letter 83-28 (Reference 4), to improve reactor trip system reliability.

The reactor trip switchgear was modified to provide a redundant/backup means to automatically trip the breakers. An automatic shunt trip relay was installed which de-energizes on a reactor trip signal and energizes the shunt trip attachment to trip the breaker. The automatic shunt trip relay, test pushbuttons, and test jack connectors are located on a panel installed into the reactor trip breakers instrument compartment.

Test jack connectors and pushbuttons are provided to test the automatic shunt trip devices and to verify breaker operations and response time.

7.2.2.1.7 Primary Power Source

The source of electrical power for the measuring elements and the actuation of circuits in the engineered safeguards instrumentation and the reactor protection system are described in Chapter 8.

7.2.2.2 **Protective Actions**

Rapid reactivity shutdown is provided by the insertion of control rod assemblies by free-fall. Duplicate series-connected circuit breakers supply all power to the control rod assembly drive mechanisms. The control rod assembly must be energized to remain withdrawn from the core. Automatic reactor trip occurs upon the loss of power to the control rod assemblies. The trip breakers are opened by the undervoltage coils on both breakers. The undervoltage coils, which are normally energized, become de-energized by any one of the several trip signals.

The design of the devices providing signals to the circuit breaker undervoltage trip coils is such as to cause these coils to trip the breaker on reactor trip signal or power loss.

Certain reactor trip channels are automatically bypassed at low power where they are not required for safety. Nuclear source range and intermediate range trips are specifically provided for protection at low power or subcritical operation. At higher power operations they are bypassed by manual action.

During power operation, a sufficient amount of rapid shutdown capability in the form of control rod assemblies is administratively maintained by means of the control rod insertion limit monitors. Administrative control requires that all shutdown group rods be in the fully withdrawn position during power operation except during low power physics testing.

Reactor trips, means of actuation, and the coincident circuit requirements are listed in Table 7.2-1. The interlocks, referred to in Table 7.2-1, are listed in Table 7.2-3.

7.2.2.2.1 Manual Reactor Trip

The manual actuating devices are independent of the automatic trip circuitry and are not subject to failures which make the automatic circuitry inoperable. Actuating either of two manual trip devices located in the control room initiates a reactor trip and a turbine trip.

7.2.2.2.2 Power Range High-Neutron-Flux Reactor Trip

This circuit trips the reactor when two of the four power range channels read above the trip setpoint. There are two independent trip settings, a high and a low setting. The high trip setting provides protection during normal power operation. The low setting, which provides protection during start-up, can be manually bypassed when two out of the four power range channels read above approximately 10% power (P-10). A reading of three out of the four channels below 10% automatically reinstates the trip function. The high setting is always active.

7.2.2.2.3 Intermediate Range High-Neutron-Flux Reactor Trip

This circuit trips the reactor when one out of the two intermediate range channels reads above the trip setpoint. This trip, which provides protection during reactor start-up, can be manually bypassed if two out of four power range channels are above approximately 10%. Three out of four channels reading below this value automatically reinstate the trip function. The intermediate channels (including detectors) are separate from the power range channels.

7.2.2.2.4 Source Range High-Neutron-Flux Reactor Trip

This circuit trips the reactor when one of the two source range channels reads above the trip setpoint. This trip, which provides protection during reactor start-up, can be manually bypassed when one of two intermediate range channels reads above the P-6 setpoint value, and it is automatically reinstated when both intermediate range channels decrease below this value (P-6). This trip is also bypassed by two out of four high-power-range signals (P-10). The trip function can also be reinstated below the P-10 setpoint value by an administrative action requiring coincident manual actuation. The trip point is set between the source range power level corresponding to the P-6 setpoint value and the maximum source range power level.

7.2.2.2.5 Overtemperature Delta T Reactor Trip

The purpose of this trip is to protect the core against departure from nucleate boiling. The allowable delta T for this tripping function is continuously calculated for each loop from the following equation:

$$\Delta T \leq \Delta T_0 \left[K_1 - K_2 \left(\frac{1 + \tau_1 s}{1 + \tau_2 s} \right) (T - T') + K_3 (P - P') - f(\Delta I) \right]$$

where: ΔT_0= indicated ΔT at rated thermal power, °F
T= average reactor coolant temperature, °F
T'= reference average reactor coolant temperature, °F
P= pressurizer pressure, psig
P'= reference pressurizer pressure, psig
K_1= OTΔT equation coefficient, unitless
K_2, K_3= OTΔT equation coefficients accounting for DNB effect of variations in system temperature and pressure, $°F^{-1}$, $psig^{-1}$
ΔI= P_{top}-P_{bot}, where P_{top} and P_{bot} are the percentage of power in the top and bottom halves of the core, respectively
$f(\Delta I)$= function to account for DNB effect of axial power skewing
τ_1, τ_2= lead-lag time constants, sec
s= Laplace transform variable, sec^{-1}

The allowable delta T is calculated for each reactor coolant loop. A trip occurs when the delta T in two out of the three (2/3) loops exceed the allowable delta T as calculated by the above equation. Initiation of automatic turbine load runback by means of an overtemperature delta T signal is discussed in Section 7.2.2.5.

7.2.2.2.6 Overpower Delta T Reactor Trip

The purpose of this trip is to protect against excessive power level (fuel rod rating protection). The allowable delta T for this tripping function is continuously calculated for each loop from the following equation:

$$\Delta T \le \Delta T_0\left[K_4 - K_5\left(\frac{\tau_3 s}{1+\tau_3 s}\right)T - K_6(T - T') - f(\Delta I)\right]$$

where: ΔT_0= indicated ΔT at rated thermal power, °F
T= average reactor coolant temperature, °F
T'= reference average reactor coolant temperature, °F
K_4= OPΔT equation coefficient, unitless
K_5, K_6= OPΔT equation coefficients accounting for effect of variations in system temperature $°F^{-1}$
ΔI= P_{top}-P_{bot}, where P_{top} and P_{bot} are the percentage of power in the top and bottom halves of the core, respectively
$f(\Delta I)$= function to account for effect of axial power skewing
τ_3= lead-lag time constant, sec
s= Laplace transform variable, sec^{-1}

The allowable delta T is calculated for each reactor coolant loop. A trip occurs when the delta T in two of the three (2/3) loops exceeds the allowable delta T as calculated by the above equation. Initiation of automatic turbine load runback by means of an overpower delta T signal is discussed in Section 7.2.2.5.

7.2.2.2.7 Pressurizer Low-Pressure Reactor Trip

The purpose of this trip is to protect against excessive core steam voids and to limit the necessary range of protection afforded by the overtemperature delta T trip. This trips the reactor on coincidence of two out of the three low pressurizer pressure signals. This trip is blocked when three of the four power range channels and two of the two turbine first-stage pressure channels read below approximately 10% power (P-7). Each channel is lead-lag compensated.

7.2.2.2.8 Pressurizer High-Pressure Reactor Trip

The purpose of this trip is to limit the range of required protection from the overtemperature delta T trip and to protect against reactor coolant system overpressure. The reactor is tripped on coincidence of two out of the three high pressurizer pressure signals.

7.2.2.2.9 Pressurizer High Water Level Reactor Trip

This trip is provided as a backup to the pressurizer high-pressure reactor trip. The coincidence of two out of the three pressurizer high water level signals trips the reactor. This trip is blocked when three of the four power range channels or two of two turbine first-stage pressure channels read below approximately 10% power.

7.2.2.2.10 Low Reactor Coolant Flow Reactor Trips

These trips protect the core from departure from nucleate boiling following a loss-of-coolant flow. The means of sensing loss-of-coolant flow are described below:

1. A low-flow signal generated by two out of three low-flow signals per primary coolant loop will cause a reactor trip. Above the P-7 setpoint (approximately 10% power), low flow in any two loops results in a reactor trip. Above the P-8 setpoint (approximately 35% power), low flow in any loop results in a reactor trip.
2. Opening of the reactor coolant pump breakers results in a reactor trip by acting directly on the reactor trip circuits. Above the P-7 setpoint the reactor trips on two open-breaker signals. Above the P-8 setpoint the reactor trips on one open-breaker signal. One open-breaker signal is generated for each reactor coolant pump.
3. Above the P-7 setpoint an undervoltage or underfrequency signal from any two reactor coolant pump buses results in a reactor trip. There is one underfrequency and two undervoltage sensors per bus. An underfrequency signal (2/3) directly trips all of the reactor coolant pumps, and if the power level is above the P-7 setpoint, a reactor trip will also result. These trips do not meet IEEE-279 from sensor to actuation device and are therefore backup trips.

The logic for these tripping functions is shown schematically in Figure 7.2-3.

7.2.2.2.11 Safety Injection System Actuation Reactor Trip

A reactor trip occurs when the safety injection system is actuated. The means of actuating the safety injection system trips are:

1. Low-low pressurizer pressure.
2. High steam-line differential pressure.
3. High steam flow in coincidence with low steam-line pressure or low T_{avg}.
4. High containment pressure.
5. Manual.

These trips are listed in Table 7.2-1. Since the safety injection system actuations not only trip the reactor but initiate various components of the engineered safeguards, the logic diagrams and chain of events may be found in Figure 7.5-1.

7.2.2.2.12 Turbine Trip Reactor Trip

A turbine trip is sensed by two out of three signals from autostop oil pressure or four out of four stop valve closure signals. A turbine trip causes a direct reactor trip above approximately 10% power and results in a controlled short-term release of steam to the condenser, which removes sensible heat from the reactor coolant system and thereby avoids steam generator safety valve actuation.

In addition, this trip is independently actuated by the Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC) should the RPS fail to actuate a trip. Above a preset turbine power (C-20 permissive), two out of three low steam generator water level signals in two out of three steam generators will initiate a trip provided a time delay incorporated into the AMSAC is satisfied.

The following conditions automatically trip the turbine generator:

1. Turbine overspeed.
2. Generator transformer and line faults or both output breakers open above 15% turbine power.
3. Low condenser vacuum.
4. Thrust-bearing oil high pressure.
5. Low lube oil pressure.
6. Low auto-stop oil pressure.
7. Low intake canal level.

8. Both feedwater pumps tripped.
9. Electro-hydraulic control power failure.
10. Anti-motoring.
11. Safety Injection.
12. High-high steam generator level.
13. High-high sixth point feedwater heater level (time delay).
14. Stop valves shut.
15. Reactor trip.
16. Manual trip.
17. AMSAC actuation.

7.2.2.2.13 Low Feedwater Flow Reactor Trip

This trip protects the reactor from a sudden loss of its heat sink. The trip is actuated by a steam/feedwater flow (low feedwater flow) mismatch (one out of two) in coincidence with low water level (one out of two) in any steam generator.

7.2.2.2.14 Low-Low Steam Generator Water Level Reactor Trip

The purpose of this trip is to protect the steam generator in the case of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a flow mismatch reactor trip. The trip is actuated on two out of the three low-low water level signals in any steam generator. This trip is blocked for a steam generator in a loop with the loop stop valves closed.

In addition, a further drop in steam generator water level will cause an independently actuated trip by AMSAC under the same conditions specified in Section 7.2.2.2.12 above.

7.2.2.3 **Rod Stops**

Rod stops are added to prevent a reactor trip or prevent an abnormal condition from increasing in magnitude, which would cause a reactor trip. The automatic rod withdrawal function of the reactor control system is disabled. Rod stops continue to prevent unintentional manual rod withdrawal.

Rod stops are given in Table 7.2-4. Some of these have been previously noted under permissive circuits but are listed again, for completeness.

Rod stops actuated by overpower delta T or overtemperature delta T initiate turbine runback via load reference.

7.2.2.4 **Rod Drop Detection**

Two independent systems are provided to sense a rod drop: a rod bottom position detection system, and a system that senses sudden reduction in ex-core neutron flux. Both detection systems initiate alarms in the main control room.

The rod drop detection circuit from neutron flux consists basically of a derivative network. Since a dropped control rod assembly rapidly depresses the local neutron flux, the decrease in flux is detected by one or more of the power range detectors. The sudden decrease in detector current appears as a signal out of the derivative network. A signal output greater than a preset value (approximately 5%) trips an associated bi-stable. Any one of the four power range channels will actuate the rod drop alarm. The dropped-rod circuit is described in Section 7.4.3.

The backup indication for the dropped control rod assembly is the rod bottom signal derived for each rod from its individual position indication system. With the position indication system, initiation of protection is not dependent on location, reactivity worth, or power distribution changes.

Figure 7.4-2 indicates schematically the nuclear instrumentation system, including the dropped control rod assembly alarm.

7.2.2.5 **Automatic Turbine Load Runback**

Load runback is also initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation, which might lead to a minimum DNBR less than the design DNBR limit (Section 3.2.3).

A turbine load reference reduction is initiated by an overtemperature or overpower delta T signal in two out of three loops.

The turbine runback signal is accompanied by rod withdrawal stops.

7.2.2.6 **Control Group Rod Insertion Monitor**

The control group rod insertion limit, Z_{LL}, is calculated as a linear function of power. The equation is:

$$Z_{LL} = A(\Delta T)_{auct} + C$$

where A is a preset, manually adjustable gain and C is a preset, manually adjustable bias. The $(\Delta T)_{auct}$ is the auctioneered value of the temperature differences. Each loop has its measured value for delta T; the auctioneered value is the median value.

An insertion limit monitor with two alarm setpoints is provided for the control banks. See Figure 7.2-9 for illustration of the monitor circuit. A description of control and shutdown rod groups is provided in Section 7.3. The “low” alarm alerts the operator of an approach to a reduced shutdown reactivity situation requiring boron addition by following procedures with the chemical and volume control system. If the actuation of the "low-low" alarm occurs, the operator should take immediate action to add boron to the system.

7.2.2.7 **Reactor Coolant Flow Measurement**

Elbow taps are used on each of the three loops in the reactor coolant system as an instrument device that indicates the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap readout has been well established by the following equation: $\Delta P/\Delta P_o = (\omega/\omega_o)1.8$, where ΔP_o is the referenced pressure differential with the corresponding referenced flow rate ω_o and ΔP is the pressure differential with the corresponding referenced flow rate ω. The full-flow reference point was established during initial unit start-up. The low-flow trip point was then established by extrapolating along the correlation curve. The technique has been well established in providing core protection against low coolant flow in Westinghouse pressurized water reactor plants. The expected absolute accuracy of the channel is within ±10%, and field results have shown the repeatability of the trip point to be within ±1%. The analysis of the loss-of-flow transient presented in Section 14.2.9 assumes instrumentation error of ±3%.

7.2.2.8 **Reactor Coolant Pump Trip**

Generic Letter 85-12 (Reference 2) required the implementation of an approved manual reactor coolant pump (RCP) trip criterion. The need for RCP trip is a result of excessive peak clad temperatures during small-break LOCA events with forced reactor coolant flow. The trip criteria must distinguish between LOCA and non-LOCA events where forced reactor coolant flow is beneficial to transient mitigation. RCP trip criterion is based on subcooling margin concurrent with at least one HPSI pump in operation and capable of delivering flow to the Reactor Coolant System (RCS).

7.2.3 System Evaluation

7.2.3.1 **Departure From Nucleate Boiling**

The following is a description of how the reactor protection system prevents departure from nucleate boiling.

The variables affecting the DNBR are:

1. Thermal power.
2. Coolant flow.
3. Coolant temperature.
4. Coolant pressure.

5. Core power distribution.

Figure 7.2-1 illustrates the typical core limits for which the DNBR for the hottest fuel rod is equal to the design DNBR limit (Section 3.2.3) and shows the locus of the overpower and overtemperature delta T reactor trips as a function of T_{avg} and pressure. This illustration is derived from the inlet-temperature versus power relationships.

Figure 7.2-10 illustrates “T_{avg} - delta T” protection. Periodic measurements using the incore instrumentation system are used to verify that the actual core power distribution is within design limits.

Reactor trips for a fixed high pressurizer pressure and for a fixed low pressurizer pressure are provided to limit the pressure range over which core protection depends on the overpower and overtemperature delta T trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these parameters. However, for all cases in which the calculated DNBR approaches the design DNBR limit (Section 3.2.3), a reactor trip on overpower and/or overtemperature delta T would also be actuated.

The delta T trip functions are based on the differences between measured hot-leg and cold-leg temperatures. These differences are proportional to core power.

The delta T trip functions are provided with a nuclear differential flux feedback to reflect a measure of axial power distribution. This will assist in preventing an adverse axial distribution that could lead to exceeding the allowable core conditions.

In the event of a difference between the upper and lower ion chamber signals that exceeds the desired range, automatic feedback signals are provided to reduce the overpower/overtemperature trip setpoints, to block rod withdrawal, and to reduce the load to maintain appropriate operating margins to these trip setpoints.

7.2.3.2 **Control/Protection Interaction**

7.2.3.2.1 Nuclear Flux

Four power range nuclear flux channels are provided for overpower protection. On three-loop plants only one signal is used for automatic control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection. In principle, the same failure may cause rod withdrawal and hence overpower; however, the automatic rod withdrawal capability of the reactor control system has been disabled. The two-out-of-four overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

In addition, the control system will respond only to rapid changes in indicated nuclear flux; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear channel will block rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint. Automatic rod withdrawal function of the reactor control system is disabled.

7.2.3.2.2 Coolant Temperature

The delta-T and T_{avg} signals developed in the reactor protection system for overtemperature delta-T and overpower delta-T reactor trips are also used in the reactor control system for rod position, steam dump, feedwater and pressurizer level control. Circuit isolators are installed to prevent a failure in the reactor control system from propagating back into the protection channels. In the control system, the delta-T and T_{avg} signals from each of the three protection channels are sent to Median Signal Selector (MSS) auctioneering circuits. The MSS is designed to prevent a failed protection system delta-T or T_{avg} signal from precipitating an inaccurate control system response. Under normal operating conditions with no failures in any RCS narrow range temperature instrument channel, the MSS will reject both the highest and lowest of the three signals received and pass to the control system only the signal whose value falls between the high/low extremes (i.e., median signal). If two of the three input signals have identical values, the MSS will select one of the two identical signals for control until a deviation between the two is detected, at which point the median signal will be passed to the control system as discussed above. If one of the three inputs should fail completely, the MSS will reject the failed signal and select the highest of the remaining two valid inputs for reactor control. The use of the Median Signal Selector circuits in the reactor control system satisfies the Control and Protection System interaction requirements of IEEE 279-1971, and prevents a spurious low temperature signal from causing rod withdrawal. Automatic rod withdrawal function of the reactor control system is disabled. Disabling automatic rod withdrawal also prevents unintended rod withdrawal on other spurious signals.

7.2.3.2.3 Pressurizer Pressure

Three pressurizer pressure protection channel signals are used for high-pressure and low-pressure protection and as inputs to the overtemperature delta T trip protection function (Figure 7.2-11). Two separate channels are used to control pressurizer spray and heaters and power-operated relief valves.

A spurious high-pressure signal from one channel can cause low pressure by actuation of pressurizer spray and/or a relief valve. Additional redundancy is provided in the protection system to ensure underpressure protection, i.e., two-out-of-three low-low-pressure reactor trip logic and two-out-of-three logic for safety injection.

The pressurizer heaters are incapable of overpressurizing the reactor coolant system. The maximum steam production rate of the pressurizer heaters is a fraction of the steam relief capacity of the pressurizer. Therefore, overpressure protection is not required for a pressure control failure; however, two-out-of-three high-pressure trip logic is used.

In addition, either of the two power-operated relief valves can easily maintain pressure below the high-pressure trip point. Each relief valve is controlled by an independent pressure channel, one of which is independent of the pressure channel used for heater control. Separation between heater control and one relief valve further precludes the likelihood of overpressurization of the system by a spurious low-pressure signal. Finally, the rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available for operator action.

7.2.3.2.4 Pressurizer Level

High pressurizer level in two of the three pressurizer level channels will initiate a reactor trip. Isolated output signals from these channels are used for pressurizer level control. A level control failure could fill or empty the pressurizer at a slow rate (on the order of half an hour or more) (Figure 7.2-12).

A reactor trip on pressurizer high level is provided to prevent filling the pressurizer in the event of a rapid thermal expansion of the reactor coolant. A rapid change from high rates of steam relief to water relief could be damaging to the safety valves, relief piping, and pressure relief tank. However, a level control failure cannot actuate the safety valves because the high-pressure reactor trip is set below the safety valve set pressure. With the slow rate of charging available, overshoot in pressure before the trip is effective is much less than the difference between reactor trip and safety valve set pressures. Therefore, a control failure does not require protection system action. In addition, ample time and alarms are available for operator action.

7.2.3.2.5 Steam Generator Water Level/Feedwater Flow

Before describing control and protection interaction for these channels, it is beneficial to review the protection system basis for this instrumentation (Figure 7.2-13).

The basic function of the reactor protection circuits associated with low steam generator water level and low feedwater flow is to preserve the steam generator heat sink for removal of long-term residual heat. Should a complete loss of feedwater occur with no protective action, the steam generators would boil dry and cause an overtemperature/overpressure excursion in the reactor coolant. Reactor trips on temperature, pressure, and pressurizer water level will trip the unit before there is any damage to the core or reactor coolant system. Redundant auxiliary feedwater pumps are provided to prevent residual heat after trip from causing thermal expansion and discharge of the reactor coolant through the pressurizer relief valves. Reactor trips act before the steam generators are dry to reduce the required capacity and starting time requirements of these pumps and to minimize the thermal transient on the reactor coolant system and steam generators. Independent trip circuits are provided for each steam generator for the following reasons:

1. Should severe mechanical damage occur to the feedwater line to one steam generator, it is difficult to ensure the functional integrity of level and flow instrumentation for that unit. For instance, a major pipe break between the feedwater flow element and the steam generator

would cause high flow through the flow element. The rapid depressurization of the steam generator would drastically affect the relation between downcomer water level and steam generator water inventory.

2. It is desirable to minimize thermal transients on a steam generator for credible loss of feedwater accidents. It should be noted that controller malfunctions caused by a protection system failure affect only one steam generator. Also, they do not impair the capability of the main feedwater system under either manual control or automatic control. Hence, these failures are far from being the worst case with respect to decay heat removal with the steam generators.

A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow and prevent that channel from tripping. A reactor trip on low-low water level, independent of indicated feedwater flow, will ensure a reactor trip if needed.

In the event of an Anticipated Transient Without Scram (ATWS) event, the ATWS Mitigation System Circuitry (AMSAC) will trip the turbine, trip the reactor, isolate blowdown lines, and start the auxiliary feedwater pumps.

In addition, the three-element feedwater controller incorporates reset on level, such that with expected controller settings a rapid increase in the flow signal would cause only a small decrease in level before the controller reopened the feedwater valve. A slow increase in the feedwater signal would have no effect at all.

A spurious low steam flow signal would have the same effects as a high feedwater signal, discussed above.

A spurious high water level signal from the protection channel used for control will tend to close the feedwater valve. This level channel is independent of the level and flow channels used for reactor trip on low-flow coincident with low level.

The actual plant response to the controlling steam generator level channel depends on the initial power level, as discussed in the subparagraphs below. In the evaluation which follows, it is postulated that in addition to the spurious high signal from the steam generator level channel controlling feedwater flow, there is a failure in an additional level channel, consistent with the design requirements of IEEE-279 for evaluation of control and protection channel interactions. Since the steam generator low-low level protection function requires two out of three channels, this function would be rendered inoperable on the steam generator experiencing the loss of feedwater.

1. 0% to approximately 20% power

   Below approximately 20% power, feedwater is normally manually controlled via the main feedwater regulating valve bypass valves. Therefore it is highly unlikely that the failure of the single level channel will result in reduced feedwater flow to a steam generator. In addition, the low power level condition results in a significant allowed operator action time to respond to reduced feedwater flow conditions before the ANS Condition II criteria applicable to the loss of normal feedwater accident are violated. Manual control of the feedwater flow also serves to increase the level of operator awareness to the status of the feedwater system and steam generator inventory. If the operator does not take action, either a high pressurizer water level trip or a low-low steam generator level signal in one of the other steam generators will trip the reactor prior to exceeding any of the applicable acceptance criteria.

2. Approximately 20% power to approximately 54% power

   The low feedwater flow trip may not be available at power levels below approximately 54% power for a 1/N loss of feedwater event because measure steam flow may not be high enough to trip the high steam flow bistables. If the heatup is severe enough, the pressurizer water level could exceed the pressurizer high water level trip setpoint.

   If a reactor trip were generated, it would: (1) alert the operator of an abnormal condition and (2) cause the voids in the shell-side inventories of the unaffected steam generators to collapse and drop the water levels below the low-low level trip setpoint, thereby actuating the auxiliary feedwater system.

   In addition, secondary heat sink requirements at power levels below 54% power can be satisfied by the unaffected steam generators due to the reduced decay heat loads. These unaffected steam generators will continue to remove heat from the RCS until a low-low level signal is generated. If the RCS heats up rapidly, or if the letdown capacity is sufficient to prevent the high pressurizer water level trip, the overtemperature delta-T trip will preclude any potential violations of the core thermal limits. Thus, due to diversity in the design of the reactor protection system, an automatic reactor trip signal will be generated by one of the signals identified above if required.

3. Approximately 54% to 100% power

   If power level is greater than approximately 54%, the IEEE-279 scenario is protected by the steam/feed flow mismatch coincident with 1/3 low steam generator level reactor trip function. The low feedwater flow function is not a direct substitute for steam generator low-low level in that it does not provide for automatic initiation of auxiliary feedwater. However, the inventory in the unaffected steam generators will provide the necessary secondary heat sink for decay removal until the water level drops sufficiently to generate a low-low signal in the unfaulted generators and initiate AFW. Again, the high pressurizer water level signal will trip the reactor before the pressurizer can go water solid and overtemperature delta-T will provide backup protection in the event that the core thermal limits are approached.

7.2.3.2.6 Steam-Line Pressure

Three pressure channels per steam line are used for steam-line break protection. These are combined with other signals as shown in Table 7.2-1. Two-out-of-three high steam flow in coincidence with two-out-of-three low T_{avg} or in coincidence with two-out-of-three low steam-line pressure and two-out-of-three differential pressure between any steam line and steam-line header will actuate safety injection.

7.2.3.2.7 Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC)

Pursuant to the requirements of 10 CFR 50.62, an AMSAC system has been installed to respond to an accident sequence should the reactor protection system (RPS) fail to shut down the reactor. The design basis for the system is summarized in Reference 4. The AMSAC provides a turbine trip, reactor trip, and auxiliary feedwater initiation, sends a signal to automatically close the steam generator blowdown valves, and trips the power supply breakers to the control rod motor generators.

The AMSAC design utilizes two turbine impulse chamber pressure sensors (one from two separate channels), as well as nine steam generator narrow range level sensors (three per steam generator) set at a range below the existing low-low level trip settings. The coincidence of two out of three steam generator level sensors taken twice and two out of two turbine impulse chamber pressure sensors detecting a pressure (load) greater than 37% automatically initiates the AMSAC. Time delays, which are set inverse to power, have been incorporated into the AMSAC circuitry to allow the RPS to function initially, if functioning properly. However, if the RPS does not initiate a reactor trip, the AMSAC will trip the reactor. These time delays are set based on consideration of the time that the steam generators take to boil down to the low-low level setpoint upon loss of main feedwater.

The AMSAC has been designed and installed to meet the following criteria:

1. Diversity - The AMSAC logic circuits have been designed and installed to be diverse from the RPS to the extent practicable.
2. Logic Power Supplies - The AMSAC logic circuit power supplies are normally powered from non-safety-related power sources independent of the RPS and capable of operating on a loss of offsite power. They can be powered from EDG #1 (Unit 1) and EDG #2 (Unit 2) by manual action.
3. Maintenance Bypasses - Bypass switches have been installed in the control room to block operation of the AMSAC's output relays when performing maintenance on the AMSAC.
4. Operating Bypasses - The C-20 permissive is utilized as the AMSAC operating bypass to enable the control room operator to bring the plant up in power during start-up to avoid spurious AMSAC actuations at power levels below 37% nominal turbine load.

The AMSAC generic design specified in Reference 6 called for AMSAC to be enabled when first stage turbine impulse pressure exceeded 40% (nominal) turbine load. This generic setpoint applies to all Westinghouse PWRs and is based on representative ATWS analyses which show that below 40% power an ATWS event without AMSAC produced only limited Reactor Coolant System (RCS) voiding. The Virginia Power AMSAC design specifies a nominal permissive (C-20) setpoint based on the generic setpoint of 40% turbine load minus an allowance for channel inaccuracies in the turbine impulse pressure channels themselves.

In some of the Reference 6 discussions, turbine load and reactor power are used interchangeably. In reality, turbine load, as represented by impulse pressure, and reactor power are not linearly related and the two values tend to deviate as power and load are reduced. The setpoint development did not specifically address this nonlinearity between turbine impulse pressure and reactor power.

As discussed in Reference 6 and supporting documents, the power level at which AMSAC is required to maintain the peak RCS pressure below the 3200 psig faulted stress limit for an ATWS has been shown generically to be 70% Rated Thermal Power (RTP). At power levels below 40% reactor power, an ATWS with no AMSAC would limit RCS voiding in the first 10 minutes to values less than obtained for the full power case with AMSAC.

For power levels between 40% and 70%, voiding is not predicted to occur until well after the peak RCS pressure is reached. Additional studies of the loss of feedwater ATWS have shown that for a C-20 setpoint corresponding to 50% RTP, the voiding that would occur without AMSAC was still less than that expected for the full power case with AMSAC (Reference 7).

Therefore the current Surry AMSAC design meets its design basis, provided AMSAC is armed at ≤40% turbine load (nominal) or ≤50% Rated Thermal Power.

Above 37% turbine load, the C-20 permissive will automatically arm the AMSAC logic. Upon the loss of a turbine impulse pressure signal or when turbine load decreases below 37%, the C-20 permissive will be blocked as noted in Table 7.2-1. The time delay is sufficient to avoid spurious trips while ensuring that the AMSAC will perform its function in the event of a turbine trip (loss of load trip).

5. Manual Initiation - Installation of the AMSAC does not preclude manual initiation of the AMSAC functions by utilizing existing manual controls for turbine trip, reactor trip, and auxiliary feedwater actuation, if necessary.
6. Electrical Independence from the RPS - Isolators have been installed at the interfaces in the AMSAC between safety-related and non-safety-related circuitry.
7. Physical Separation from Existing RPS - The AMSAC receives signals from the existing steam generator level and turbine impulse pressure instrumentation systems. However, the AMSAC cable routing is independent of RPS cable and the AMSAC equipment cabinets are located such that interaction with the RPS cabinets is precluded. Train separation requirements have also been maintained.

8. Environmental Qualification - AMSAC mitigation equipment is not required to be environmentally qualified, however, the equipment is located in mild environments in the station and will not be impacted by anticipated operational occurrences.
9. Testability at Power - End-to-end testing of the AMSAC system is performed every refueling outage. When the plant is at power, the system can be tested with the AMSAC outputs bypassed. The bypass is accomplished through permanently installed bypass switches. Status outputs to the main control board provide indication to the control room operator that the AMSAC system's outputs have been bypassed.
10. Seismic Qualification - The AMSAC panel and its components are Seismic Class I and have been seismically qualified to the requirements of IEEE-344-1975.

7.2.3.3 **Normal Operating Environment**

The normal operating environment for the main control room, and the qualification of protective equipment therein, is discussed in Section 7.7.

The average operating environment for equipment within the containment is normally maintained below 125°F. The reactor protection system instrumentation within the containment is designed for continuous operation. The temperature of the ex-core neutron detectors is maintained at or below 135°F. The detectors are designed for continuous operation at 135°F and will withstand operation at 175°F for short durations.

7.2 REFERENCES

1. T. W. Burnet, D. H. Risher, and A. C. Hall, *Reactor Protection System Diversity in Westinghouse PWR*, WCAP 7306.
2. Generic Letter 85-12, *Implementation of TMI Action Item II.K.3.5 Automatic Trip of Reactor Coolant Pumps,* June 28, 1985.
3. Letter from W. L. Stewart (Virginia Electric and Power Company) to H. R. Denton (NRC), *Response to Generic Letter 85-12: Automatic Trip of Reactor Coolant Pumps,* Serial No. 85-510B, December 6, 1985.
4. Letter from L.B. Engle (NRC) to D.S. Cruden (Virginia Electric and Power Company) *Compliance with ATWS Rule, 10 CFR 50.62,* Surry Power Station Units 1 and 2, and North Anna Power Station Units 1 and 2 (TAC Nos. 59147, 59148, 59117 and 59118), dated May 26, 1988.
5. Generic Letter 83-28, *Required Actions Based on Generic Implications of Salem ATWS Event,* July 8, 1983.
6. WCAP-10858, Rev. 1-P-A, *AMSAC Generic Design Package*, July 1987.

7. Westinghouse Technical Bulletin ESBU-TB-08, *AMSAC C-20 Interlock Permissive,* November 26, 1997.

7.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-1B	Machine Location: Reactor Containment, Elevation 18'- 4"
	11548-FM-1B	Machine Location: Reactor Containment, Elevation 18'- 4"
2.	11448-FE-45A	Conduit and Cable Tray Plan, Cable Tunnel and Vaults
	11548-FE-45A	Conduit and Cable Tray Plan, Cable Tunnel and Vaults

Table 7.2-1
REACTOR TRIPS

Reactor Trip	Coincidence Circuitry and Interlocks	Comments
1. Manual	1/2, no interlocks	Either one trips reactor
2. Power range high neutron flux		
Low setpoint	2/4, low setpoint interlocked with P-10	Manual block and automatic reset of low setting by P-10, Table 7.2-2
High setpoint	2/4, no interlocks	
3. Overtemperature delta T	2/3, no interlocks	
4. Overpower delta T	2/3, no interlocks	
5. Low pressurizer pressure (fixed setpoint)	2/3, interlocked with P-7	
6. High pressurizer pressure (fixed setpoint)	2/3, no interlocks	
7. High pressurizer water level	2/3, interlocked with P-7	
8. Low reactor coolant flow	2/3 signals per loop, interlocked with P-7 and P-8	Blocked below P-7. Low flow in 1 loop permitted below P-8
9. Monitored electrical supply to reactor coolant pumps (non-safety-related backup trip)		
Undervoltage	Low voltage on 2 out of 3 buses, interlocked with P-7	
Underfrequency	Underfrequency on 2 out of 3 buses, interlocked with P-7	Underfrequency on 2 out of 3 buses will trip all reactor coolant pumps and cause reactor trip via trip of pump breakers; indicated in next entry
Reactor coolant pump breakers	Interlocked with P-7 and P-8	Blocked below P-7. Open breaker in 1 loop permitted below P-8.

Table 7.2-1 (CONTINUED)
REACTOR TRIPS

Reactor Trip	Coincidence Circuitry and Interlocks	Comments
10. Safety injection signal (actuation)	Low-low pressurizer (2/3); or 3/4 high containment pressure; or 2/3 high differential pressure between any steam line and steam-line header; or high main steam flow in 2/3 steam lines (1/2 per line) in coincidence with either 2/3 low T_{avg} or 2/3 low stem-line pressure; or manual 1/2 (see 7.2, System Description - Protective Action for Interlocks)	Trips main feedwater pumps, which closes the associated discharge valves. Closes all feedwater control valves. Low pressurizer pressure coincident with low pressurizer level. SIS may be blocked below 2000 psig. High steam flow in coincidence with low T_{avg} or low steam-line pressure may be manually blocked below approximately 543°F.
11. Turbine-generator trip	2/3 low auto stop oil pressure interlocked with P-7 or closure of all turbine stop valves as sensed by 2 switches per stop valve (interlocked with P-7)	
12. Steam/feedwater flow mismatch, coincident with low steam generator level	1/2 steam/feedwater flow mismatch in coincidence with 1/2 low steam generator water level, any loop.	
13. Low-low steam generator water level	2/3, any loop.	
14. Intermediate range neutron flux	1/2, manual block permitted by P-10.	Below P-10 automatic reset.
15. Source range neutron flux	1/2, manual block permitted by P-6, interlocked with P-10.	Automatic block above P-10 and automatic reset below P-6.
16. Steam generator water level (AMSAC)	2/3 per steam generator in 2/3 loops after a time delay, interlocked with C-20.	Blocked below C-20 after a time delay.

Table 7.2-2
LOGIC SYMBOLS

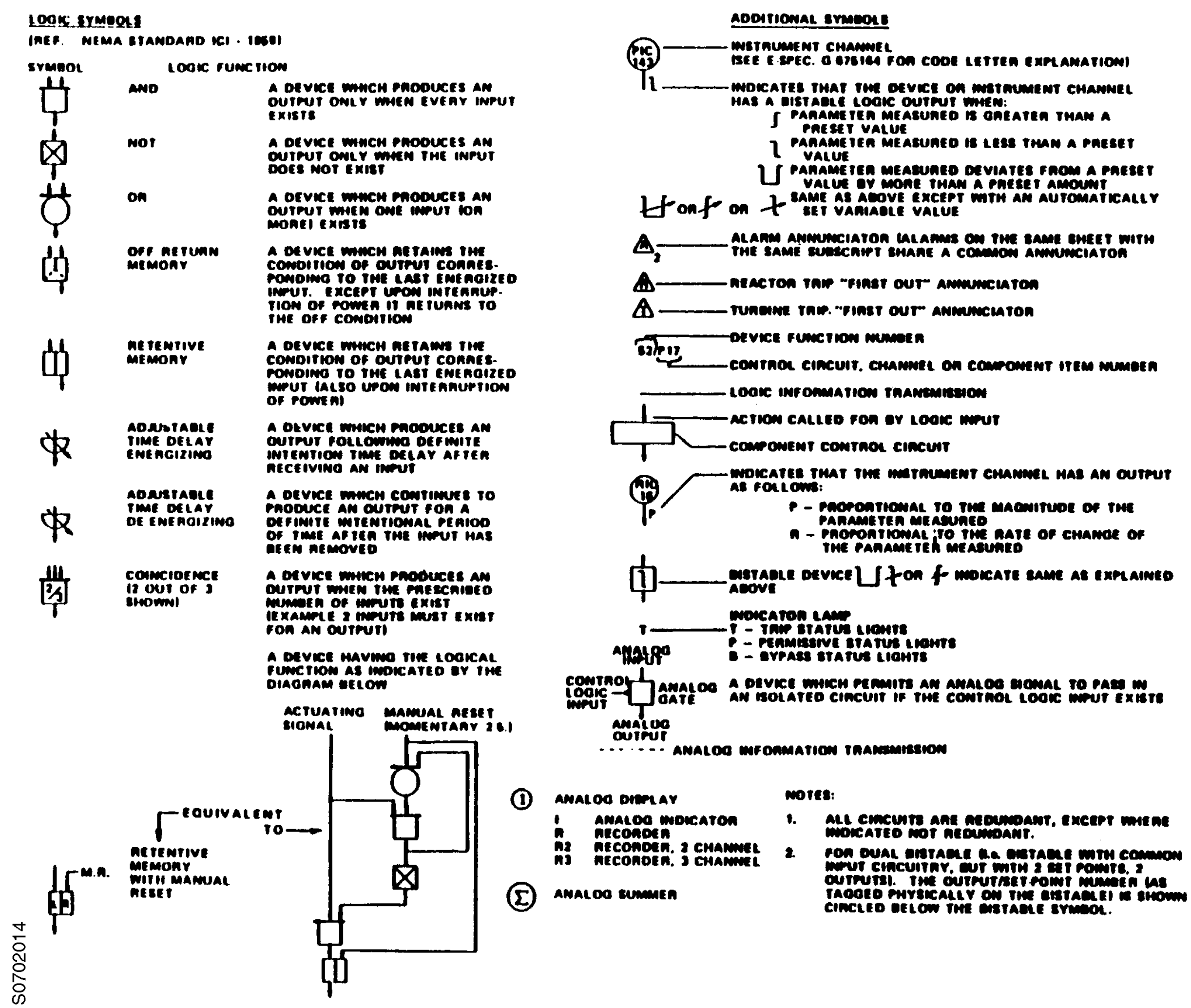


Table 7.2-2 (CONTINUED)
LOGIC SYMBOLS

Legend	
Al	alarm
Buf	buffer
f	special function (such as pressure compensation unit or lead/lag compensation)
F	amplifier
FC	flow controller (off-on unless output signal is shown)
FI	flow indicator
FLTR	filter
FS	flow steam
FT	flow transmitter
FW	flow water
Hi LRT	high-level reactor trip
Hi PRT	high-pressure reactor trip
I/I	isolation current repeater
ISOL	isolation (other than I/I)
LC	level controller (off-on unless output signal is shown)
LI	level indicator
L-Low	low level
Lo L	low level
Lo LRT	low-level reactor trip
Lo PRT	low-pressure reactor trip
L_{ref}	programmed reference level
L/L	lead/lag
LT	level transmitter
NC	nuclear flux controller
NE	nuclear detector
NI	nuclear flux indicator
NM	nuclear modifier
NQ	nuclear power
P	pressure
PC	pressure controller (off-on unless output signal is shown)
PI	pressure indicator
PM	pressure modifier
P_{ref}	programmed reference pressure

Table 7.2-2 (CONTINUED)
LOGIC SYMBOLS

Legend	
PS	power supply
PT	pressure transmitter
QM	flux modifier
R/I	resistance to current connector
RT	reactor trip
RTD	resistance temperature detector
S	control channel transfer switch (used to maintain auto channel during test of the protection channel)
SI	safety injection
sp	setpoint
T	transmitter
TC	temperature controller
TE	temperature element
TI	temperature indicator
TJ	test signal insertion jack
TM	temperature modifier
TP	test point
ϕU, L	out of core upper or lower ion chamber flux signals
$\frac{d}{dt}$	time rate of exchange
Σ	sum
f(Δq)	function of flux difference between upper and lower long ion chamber sections, f

Table 7.2-3
PROTECTION INTERLOCKS

Number	Derivation	Function
P-1	1/2 neutron flux (intermediate range) above setpoint; 1/4 neutron flux (power range) above setpoint	Blocks manual rod withdrawal (Note 1)
	2/3 overtemperature delta T above setpoint, 2/3 overpower delta T above setpoint	1. Blocks manual rod withdrawal (Note 1) 2. Initiates turbine runback via load reference
P-2	1/1 first-stage turbine pressure below setpoint	Indication only (Note 1)
P-4	Reactor trip	1. Actuates turbine trip 2. Allows auto closing of main feedwater regulating valves on T_{avg} below setpoint 3. Prevents opening of main feedwater regulating and bypass valves which were closed by safety injection or high steam generator level
P-6	1/2 neutron flux (intermediate range) above setpoint; 2/2 neutron flux (intermediate range) below setpoint	1. Allows manual block of source range reactor trip 2. Automatically defeats block of source range reactor trip
P-7	3/4 neutron flux (power range) below setpoint (from P-10); 2/2 first-stage turbine pressure below setpoint	Blocks reactor trip on low flow, reactor coolant pump breakers open in more than one loop, undervoltage, underfrequency, turbine trip, pressurizer low pressure, pressurizer high level
	2/4 power range above setpoint or 1/2 turbine impulse chamber set above setpoint (power level increasing)	Allows reactor trip on: low flow or reactor coolant pump breakers open in more than one loop, undervoltage (RCP busses), underfrequency (RCP busses), turbine trip, pressurizer low pressure and pressurizer high level
P-8	3/4 neutron flux (power range) below setpoint	Blocks reactor trip on low flow or reactor coolant pump breaker open in a single loop

Table 7.2-3 (CONTINUED)
PROTECTION INTERLOCKS

Number	Derivation	Function
	2/4 power range above setpoint (power level increasing)	Permit reactor trip on low flow or reactor coolant pump breaker open in a single loop
P-9	1/2 condenser pressure above setpoint or all circulating water outlet valves closed	Blocks air supply to condenser steam dump valves
P-10	2/4 neutron flux (power range) above setpoint	1. Allows manual block of intermediate range reactor trip Allows manual block of power range (low setpoint) reactor trip 2. Allows manual block of intermediate range rod stop (P-1) 3. Automatically blocks source range reactor trip (back-up for P-6) 4. Input to P-7
	3/4 neutron flux (power range) below setpoint	1. Defeats automatically the manual block of intermediate range reactor trip 2. Defeats automatically the manual block of power range (low setpoint) reactor trip 3. Defeats automatically the manual block of intermediate range rod stop

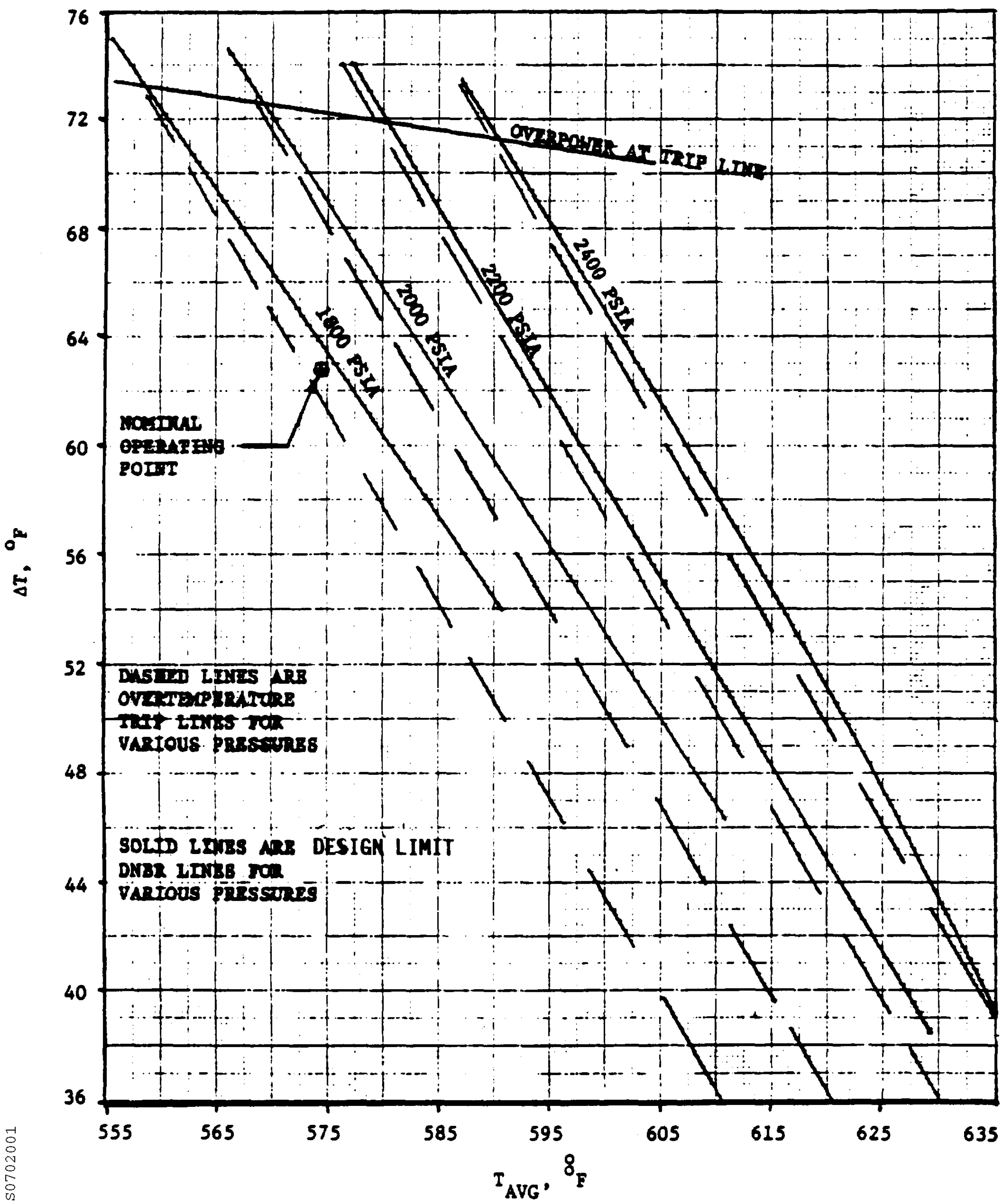
Note 1: The automatic rod withdrawal function of the reactor control system is disable.

Table 7.2-4
ROD STOPS

Rod Stop	Actuation Signal	Rod Motion To Be Blocked
Nuclear overpower	1/4 high power range nuclear flux or 1/2 high intermediate range nuclear flux	Manual withdrawal (Note 1)
High delta T	2/3 overpower delta T or 2/3 overtemperature delta T	Manual withdrawal (Note 1)
Low power	1/1 low turbine impulse pressure	Indication only (Note 1)

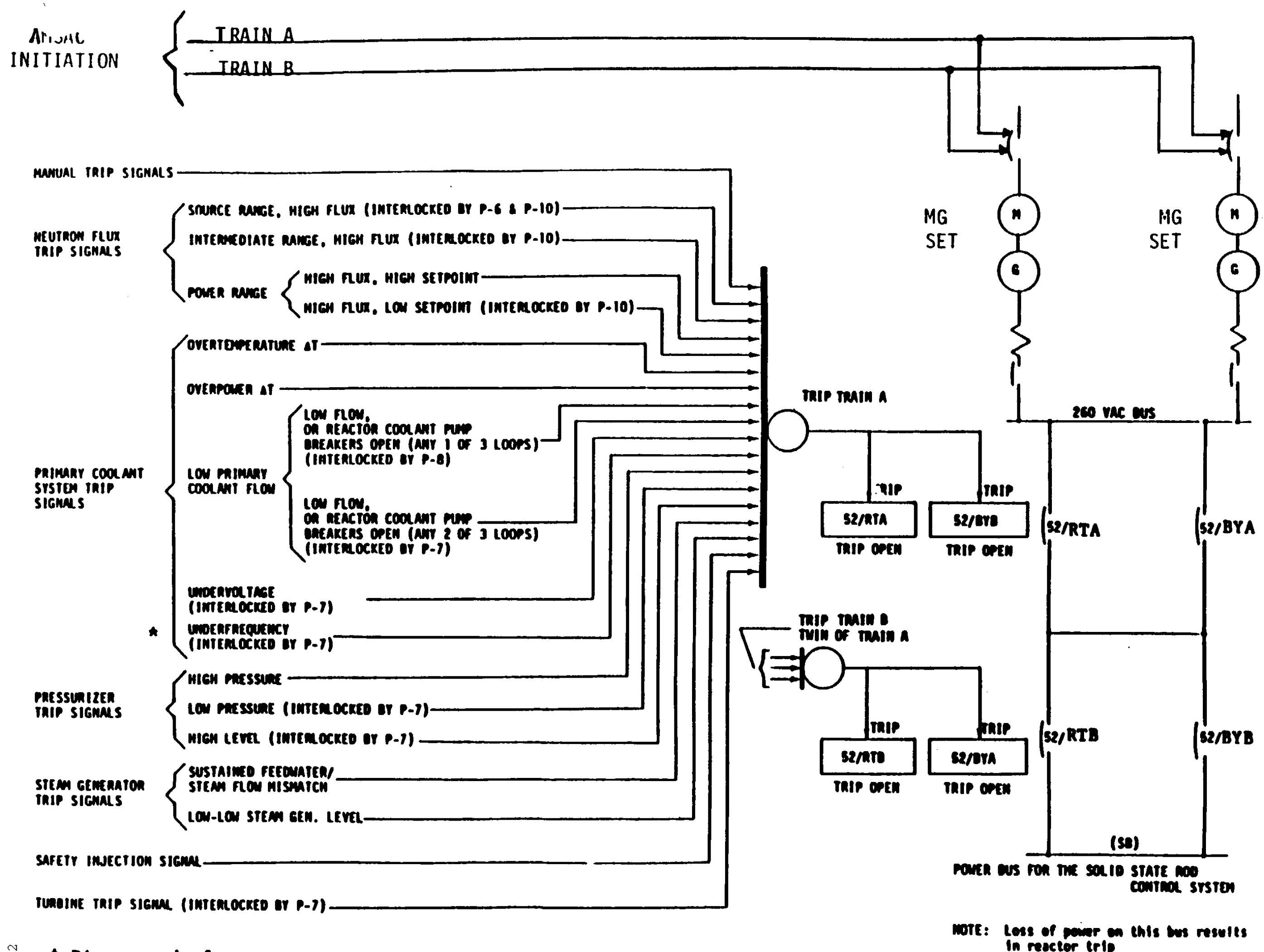
Note 1: The automatic rod withdrawal function of the reactor control system is disabled.

Figure 7.2-1
TYPICAL ILLUSTRATION OF $\Delta T - T_{avg}$ PROTECTION



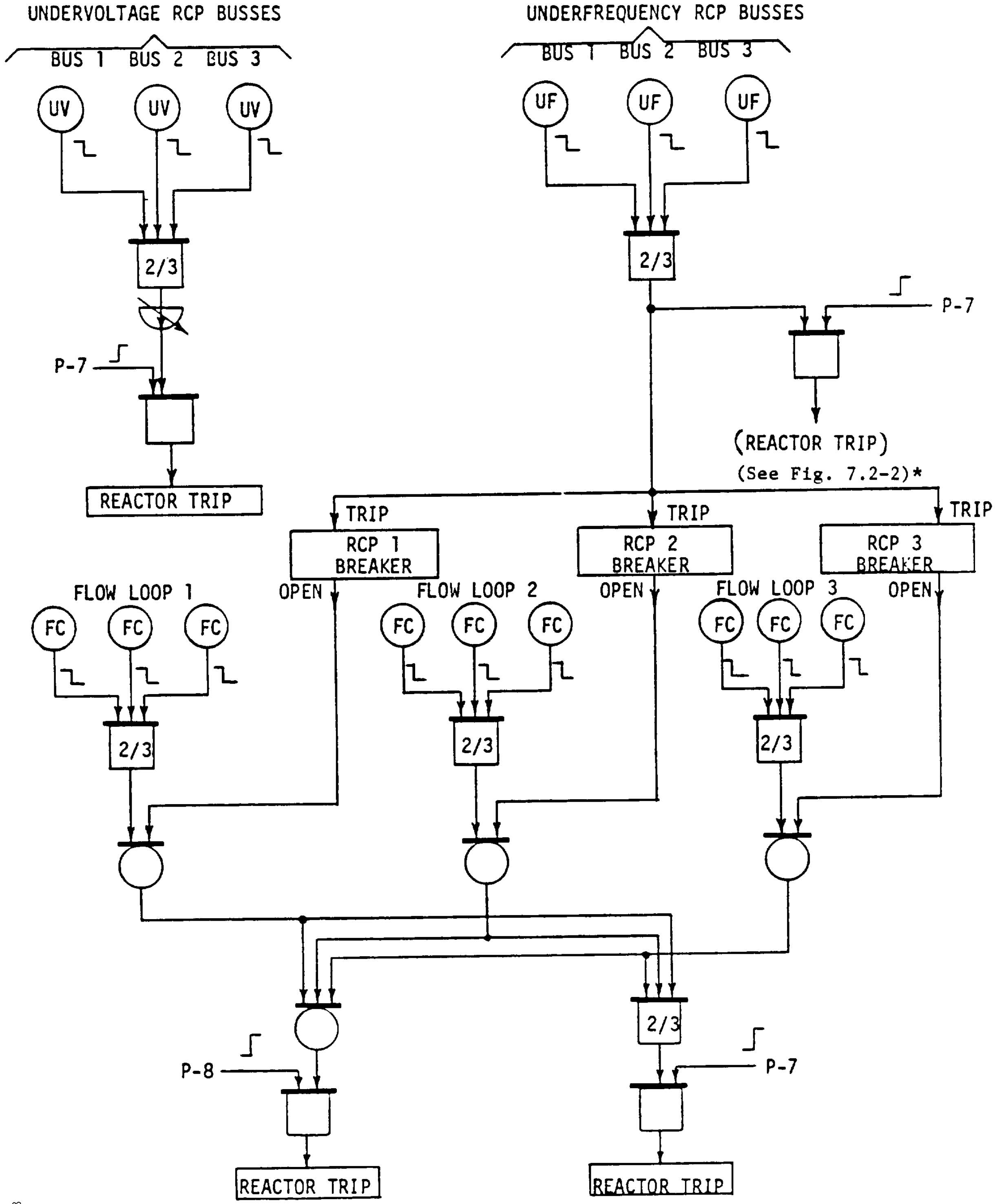
S0702001

Figure 7.2-2
REACTOR TRIP SIGNALS



* Direct underfrequency reactor trip is required only if the additional delay due to tripping through the reactor coolant pump breakers exceeds 0.1 sec.

Figure 7.2-3
LOGIC DIAGRAM FOR LOW REACTOR COOLANT FLOW TRIPS



NOTE:
See Table 7.2-2
for symbols

Figure 7.2-4
DESIGN TO ACHIEVE ISOLATION BETWEEN CHANNELS

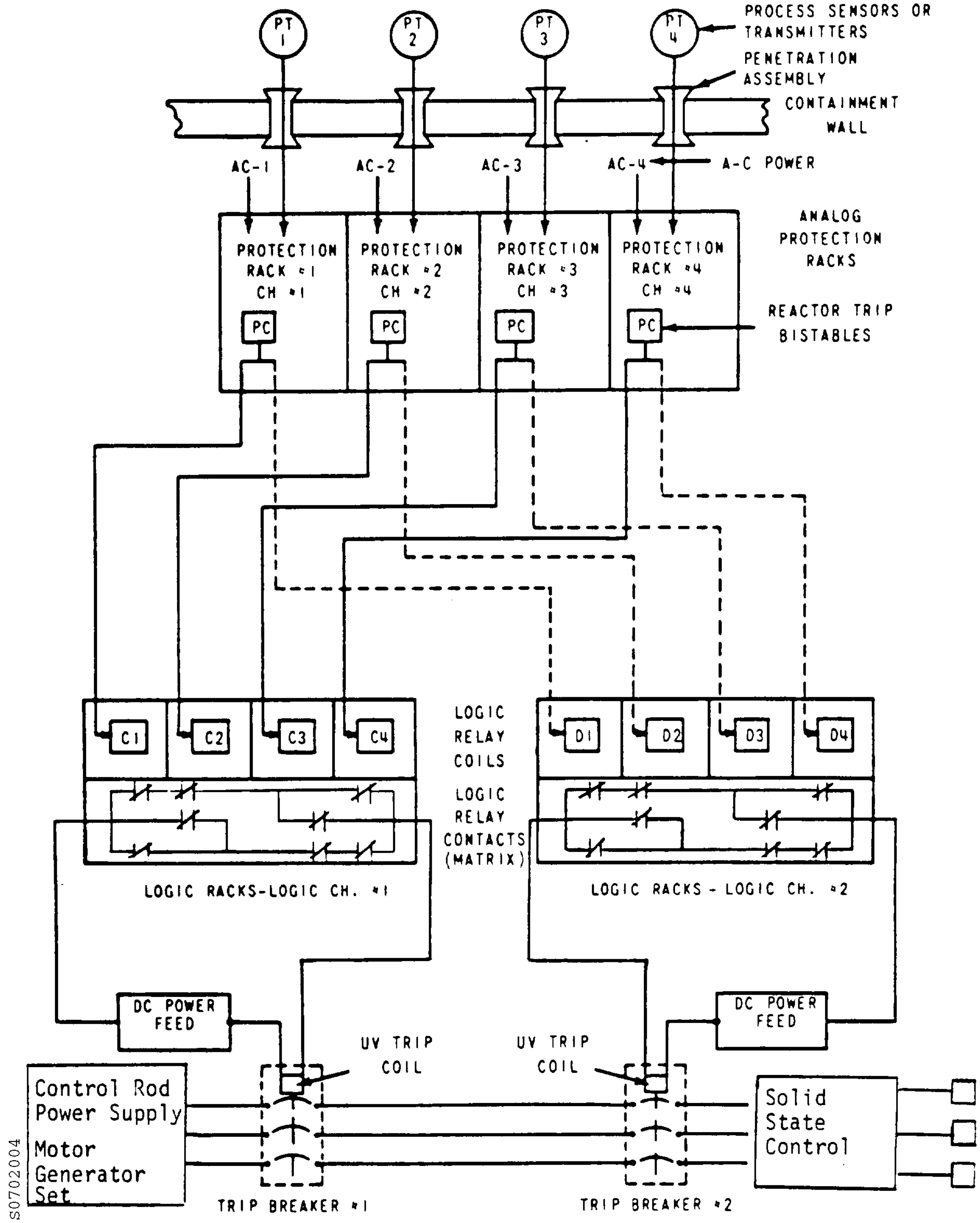
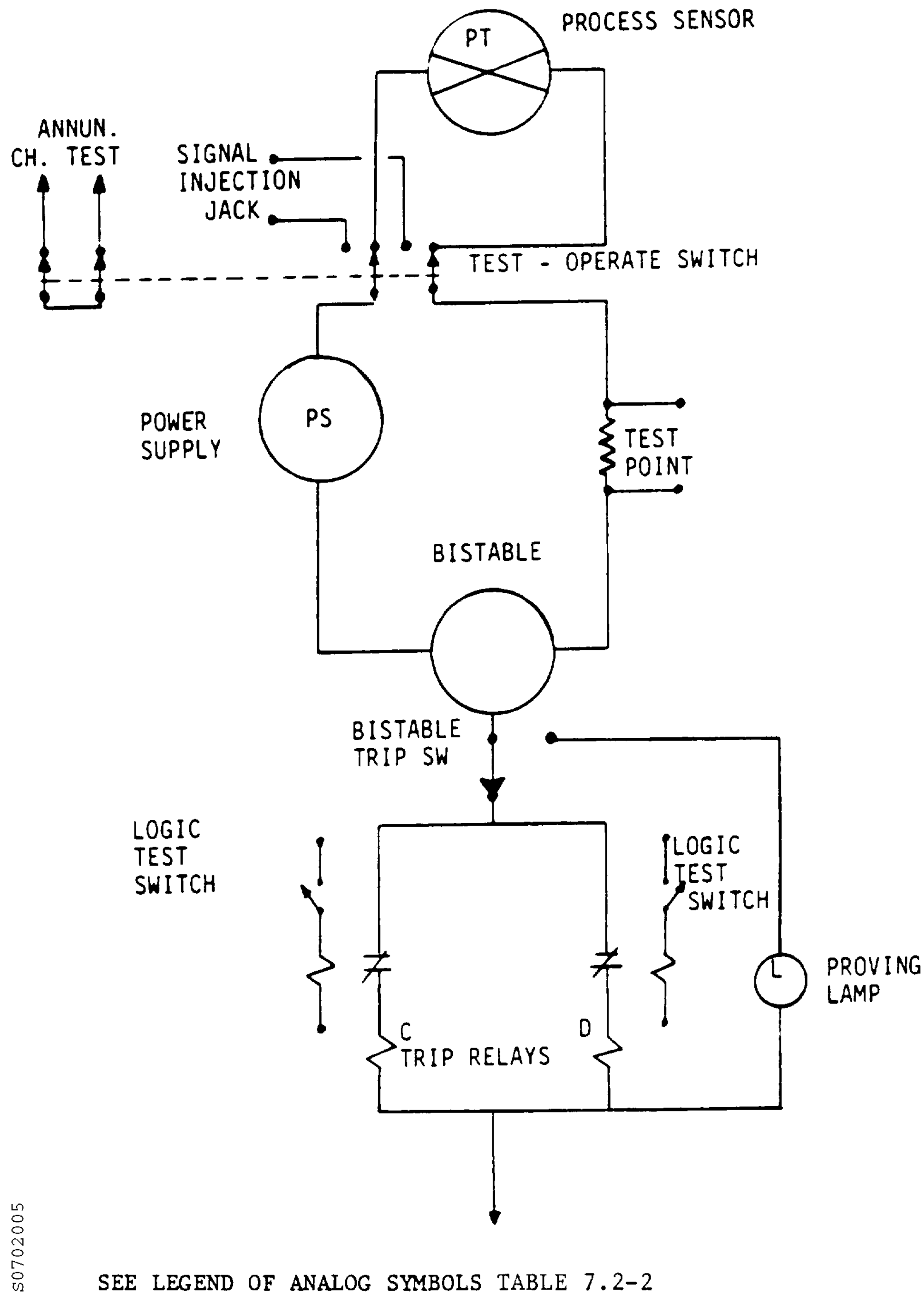


Figure 7.2-5
BASIC ELEMENTS OF AN ANALOG PROTECTION CHANNEL



SEE LEGEND OF ANALOG SYMBOLS TABLE 7.2-2

Figure 7.2-6
TRIP LOGIC CHANNELS

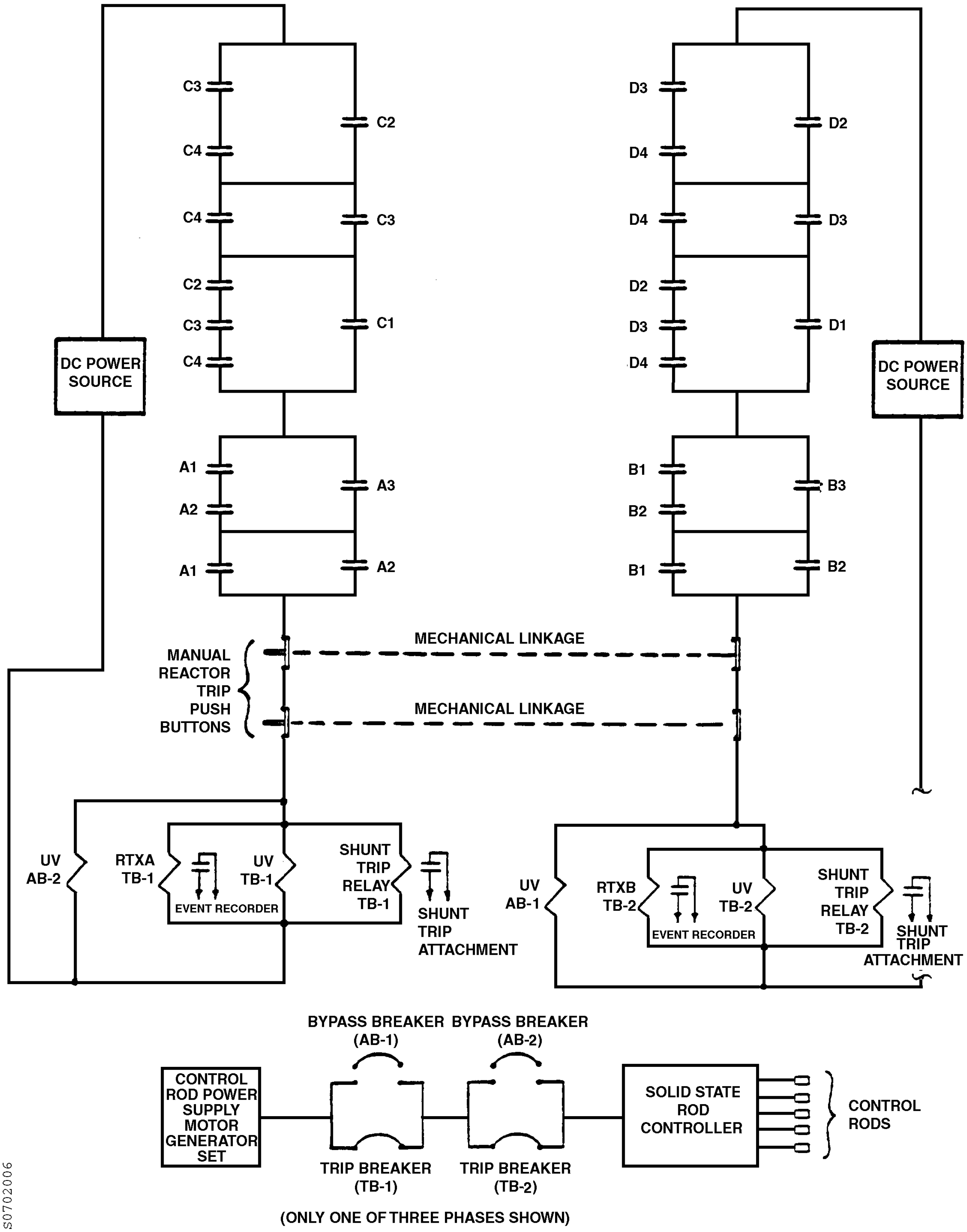
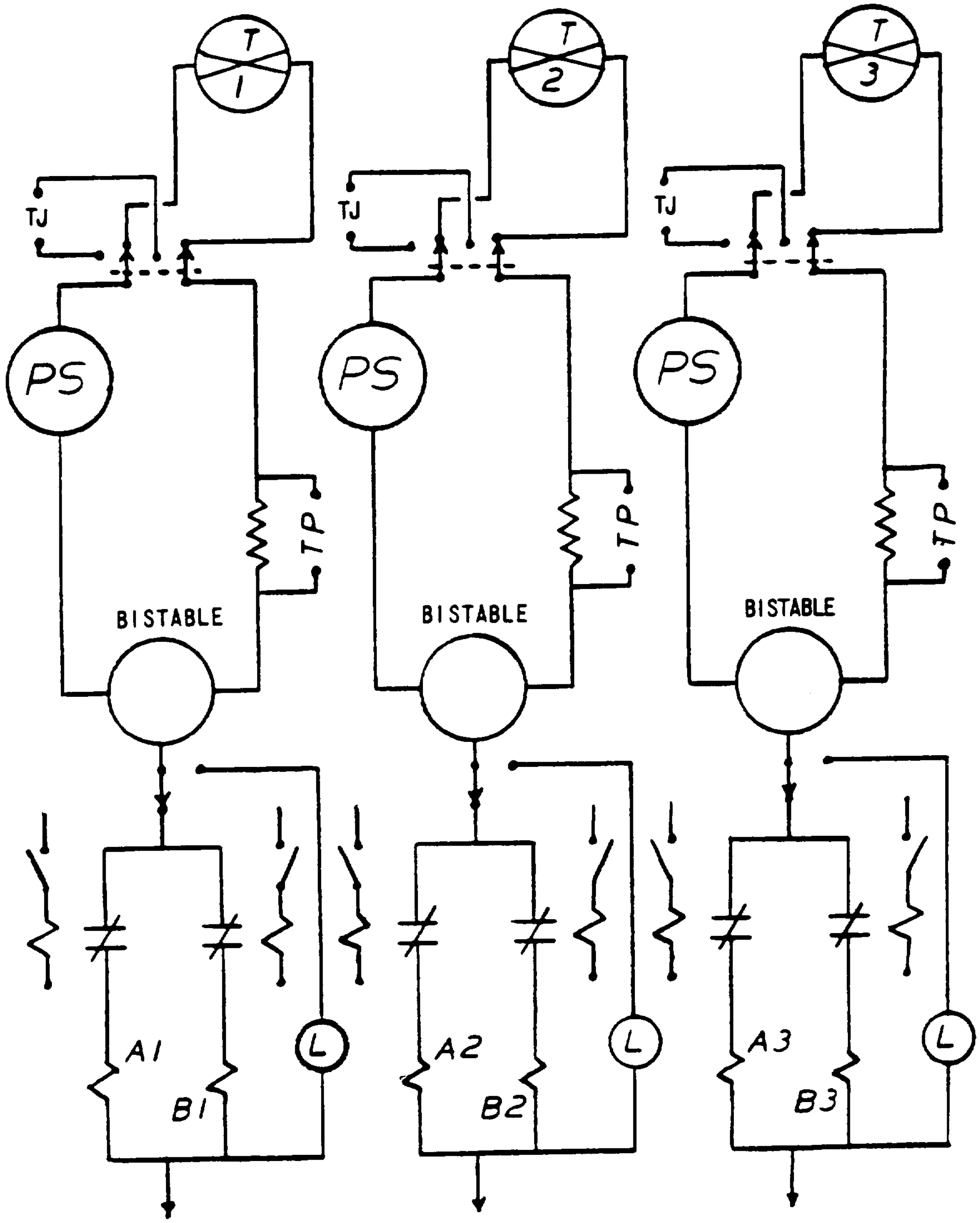


Figure 7.2-7
ANALOG CHANNELS



NOTE - REDUNDANT CHANNELS
ARE ISOLATED

SEE LEGEND OF ANALOG SYMBOLS TABLE 7.2-2

S0702007

Figure 7.2-8
LOGIC CHANNEL TEST PANELS

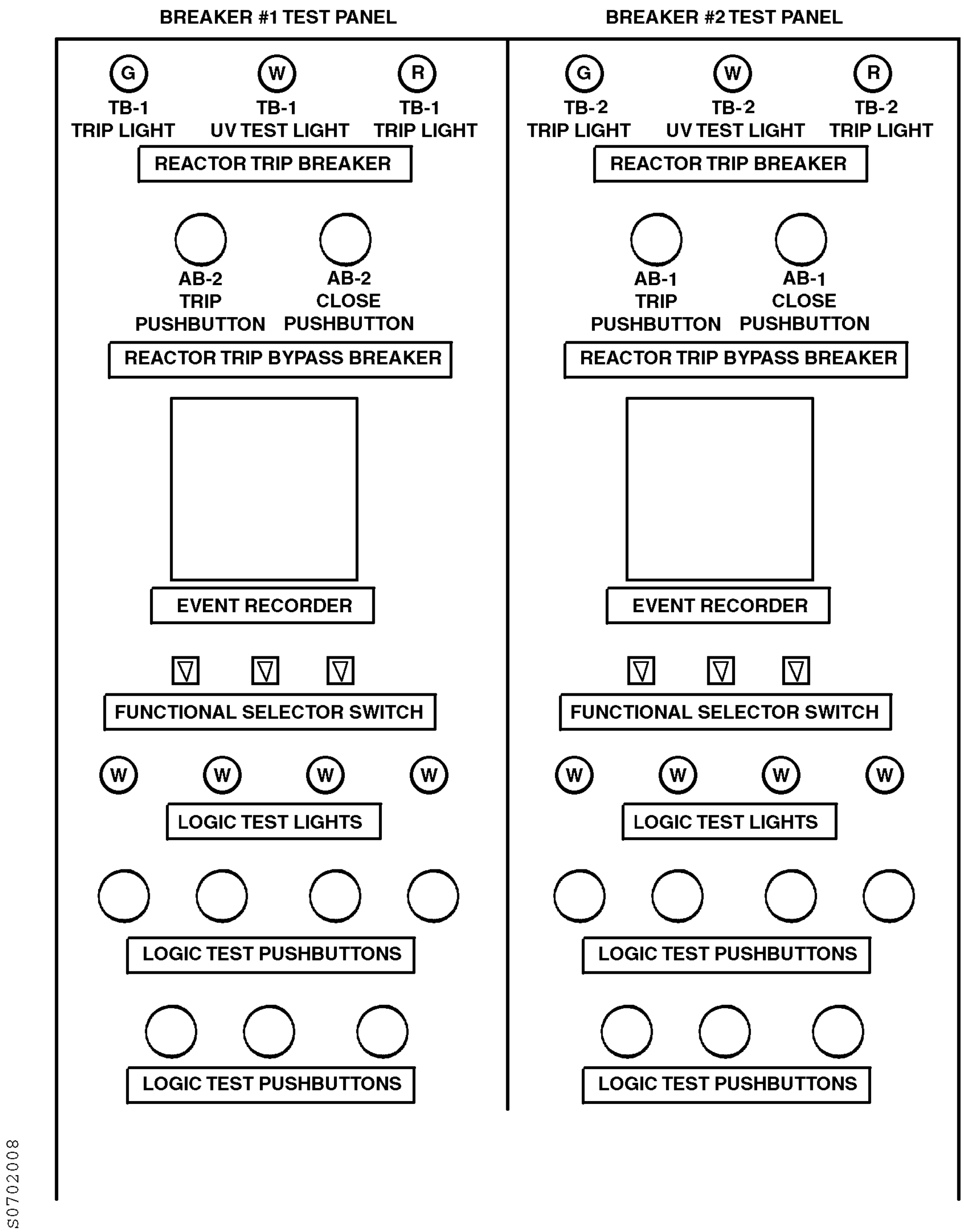
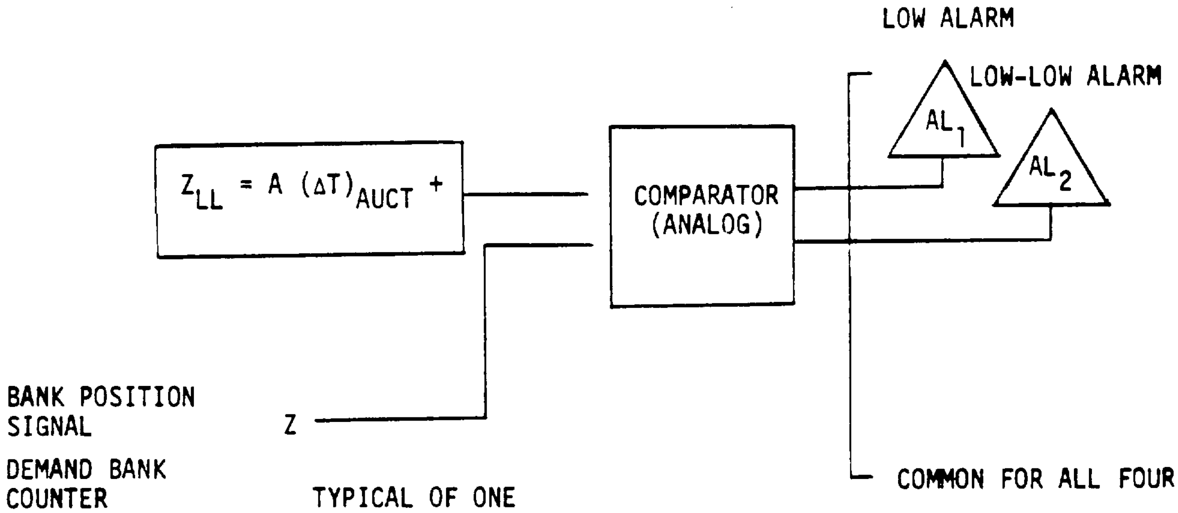


Figure 7.2-9
CONTROL GROUP ROD INSERTION MONITOR

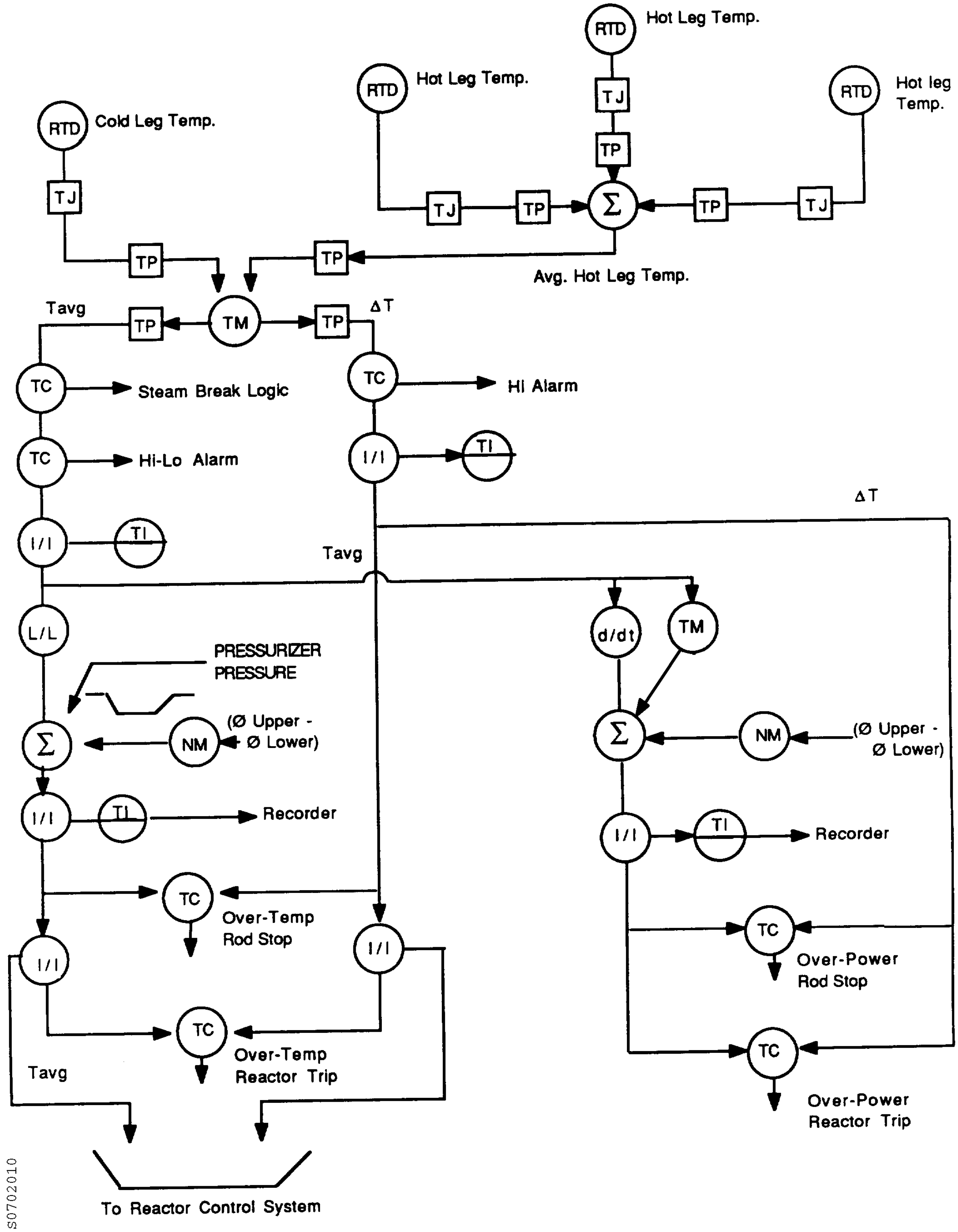


NOTE:

1. ANALOG CIRCUITRY IS USED FOR THE COMPARATOR NETWORK.
2. COMPARATOR WILL ENERGIZE LOW ALARM $(A1_1)$ IF THE DIFFERENCE BETWEEN Z AND Z_{LL} IS LESS THAN D.
3. COMPARATOR WILL ENERGIZE LOW-LOW ALARM (AL_2) IF THE DIFFERENCE BETWEEN Z AND Z_{LL} IS LESS THAN E.
4. D > E.
5. COMPARISON IS DONE FOR ALL CONTROL BANKS.

S0702009

Figure 7.2-10
T_{avg} - ΔT PROTECTION



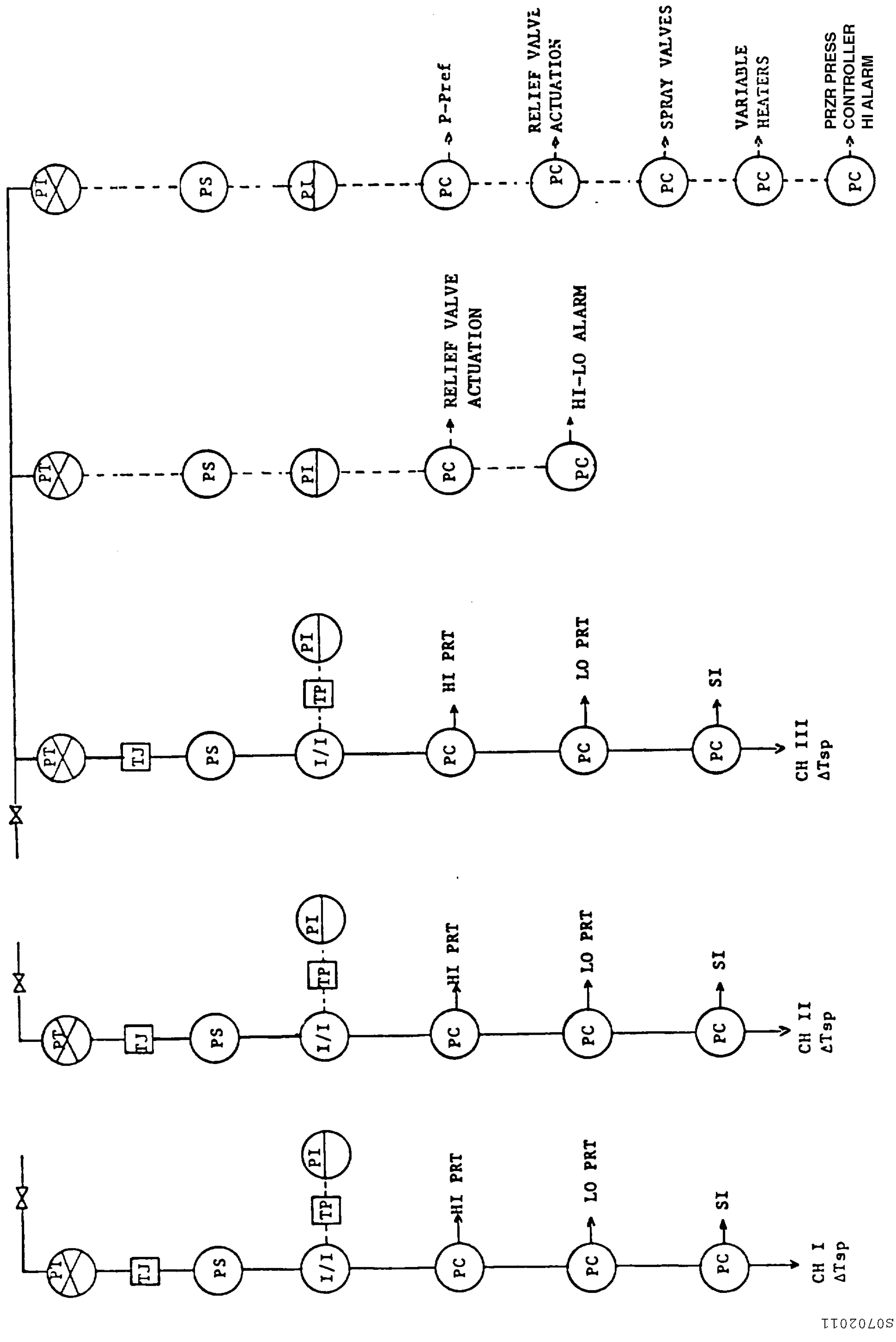


Figure 7.2-11
PRESSURIZER PRESSURE CONTROL AND PROTECTION

Figure 7.2-12
PRESSURIZER LEVEL CONTROL AND PROTECTION SYSTEM

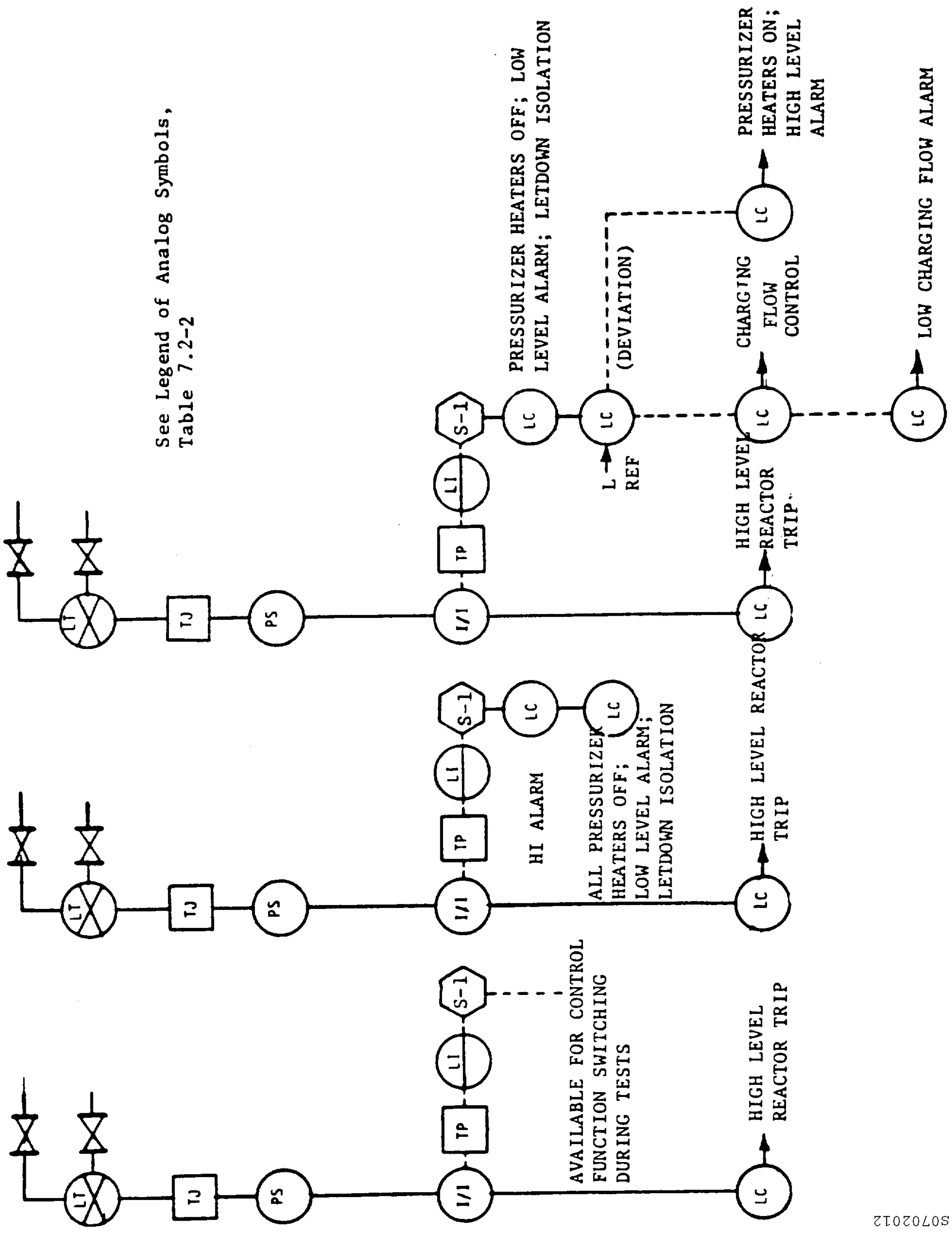
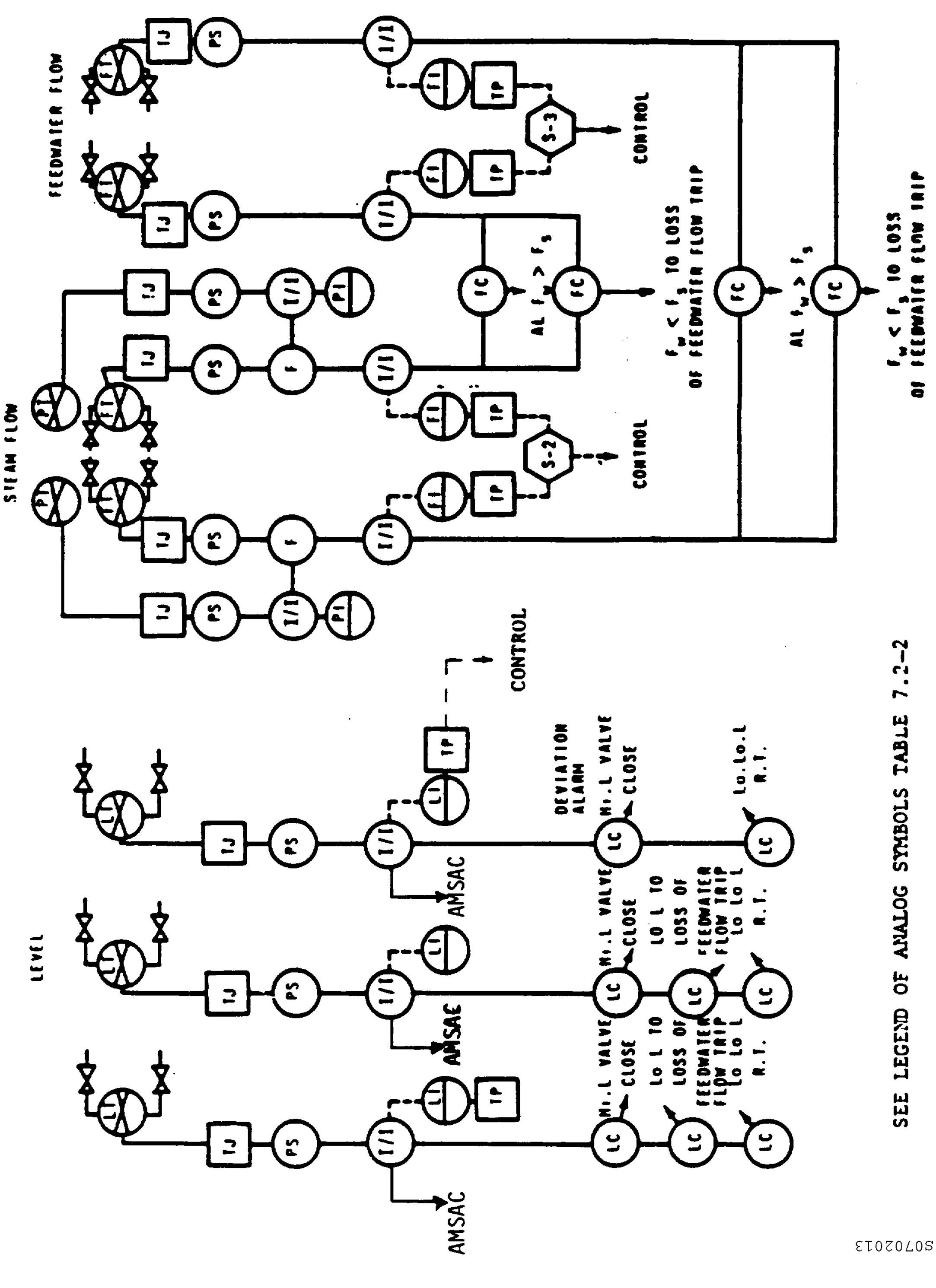


Figure 7.2-13
STEAM GENERATOR LEVEL CONTROL AND PROTECTION SYSTEM



7.3 REACTOR CONTROL SYSTEM

7.3.1 Design Bases

The reactor automatic control system is designed to reduce transients for the designed load perturbations, so that reactor trips will not occur for these load changes. Automatic rod withdrawal has been defeated; therefore, the automatic system can only respond to load reductions. Compensation for load increase must be performed manually.

The functional design of the reactor control and protection systems for the Surry Station is the same as that for H. B. Robinson Unit 2. In translating the functional requirements into control and protection equipment during the detailed design of the plant, there were some minor changes in equipment in order to:

1. Reduce the amount of equipment required to accomplish a specific control or protection function, and therefore reduce equipment maintenance time during plant operation.
2. Modify instrument and control ranges to be consistent with the plant parameters corresponding to the increased power rating of the Surry Station over that of the reference design (H. B. Robinson Unit 2).

Specific functions, however, are accomplished with the same degree of reliability and redundancy as the reference design.

Overall reactivity control is achieved by the combination of chemical shim and control rod assemblies. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short-term reactivity control for power changes is accomplished by moving control rod assemblies.

The function of the reactor control system is to provide automatic control of the control rod assemblies during power operation of the reactor. The system uses input signals including neutron flux, isolated delta T and T_{avg} signals from the reactor protection system, and turbine load. The chemical and volume control system (Section 9.1) supplements the reactor control system by boration and dilution.

There is no provision for a direct continuous visual display of primary coolant boron concentration. When the reactor is critical, the best indication of reactivity status in the core is the position of the control group in relation to power and average coolant temperature.

There is a direct relationship between control rod position and power, and it is this relationship that establishes the calculated lower insertion limit displayed on the rod insertion limit recorder. There are two alarm setpoints to alert the operator to take corrective action in the event a control group approaches or reaches its lower limit.

Any unexpected change in the position of the control group under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, periodic samples are taken for determination of the coolant boron concentration. The variation in concentration during core life provides a further check on the reactivity status of the reactor, including core depletion.

The reactor control system is designed to enable the reactor to follow load changes automatically when the output is above approximately 15% of nominal power. With automatic rod withdrawal disabled, control rod positioning may be performed manually for withdrawal and automatically for insertion when plant output is above this value, and insertion or withdrawal can be performed manually at any time.

The operator is able to select any single bank of rods for manual operation. This is accomplished with a multi-position switch so that he may not select more than one bank. He may also select automatic or manual reactor control; in either case, however, the control banks can be moved only in their normal sequence, with some overlap as one bank reaches its full withdrawal position and the next bank begins to withdraw. Relay interlocks, designed to meet the single-failure criterion, are provided to preclude simultaneous withdrawal of more than one bank of rods except in overlap regions.

The original design of the system enables the nuclear unit to accept a step load increase of 10% and a ramp increase of 5% per minute within the load range of 15% to 100% without reactor trip, subject to possible xenon limitations. Similar step and ramp load reductions are possible within the range of 100% to 15% of nominal power. With automatic rod withdrawal disabled, rods are manually withdrawn during load increase transients to maintain coolant average temperature near the programed value.

The control system is capable of restoring coolant average temperature to within the programmed temperature deadband following a scheduled or transient change in load. The coolant average temperature can be maintained by automatic or manual rod insertion during load decrease transients and manually during load increase transients.

The pressurizer water level is programmed to be a function of the average coolant temperature. This is to minimize the requirements on the chemical and volume control and waste disposal systems resulting from coolant density changes during loading and unloading from full power to zero power.

Following a reactor and turbine trip, sensible heat stored in the reactor coolant is removed, without actuating the steam generator safety valves, by means of controlled steam dump to the condenser and by injection of feedwater into the steam generators. Reactor coolant system temperature is reduced to the no-load condition. This no-load coolant temperature is maintained by steam dump to the condensers, which removes residual heat.

7.3.2 System Description

The reactor control system is designed to provide stable system control over the full range of automatic operation throughout core life without requiring operator adjustment of setpoints other than normal calibration.

A simplified block diagram of the reactor control system is shown in Figure 7.3-1. The reactor control system controls the reactor coolant average temperature by regulation of control bank rod position. The system is capable of restoring reactor coolant average temperature to the programmed value following a decrease in load. With automatic control rod withdrawal disabled, manual control rod withdrawal may be needed to restore the coolant average temperature to the programmed value following an increase in load. The programmed coolant average temperature increases linearly from zero power to the full-power condition.

The reactor control system will also compensate, to a certain extent, for reactivity changes caused by fuel depletion and/or xenon transients. Long-term compensation for these two effects is periodically made by adjustments of the boron concentration to return the control rod bank to its normal operating range.

The reactor coolant loop average temperatures are determined from hot-leg and cold-leg measurements in each reactor coolant loop. These signals are derived in the reactor protection system and sent to the reactor control system via circuit isolators. The error between the programmed average temperature and the median value of the average measured temperatures from each of the reactor coolant loops constitutes the primary control signal, as shown on Figure 7.3-2. An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks. From these input signals, the rod direction command signals are derived. The rod speed command signal varies over the corresponding range of 3.75 to 45 inches per minute, depending on the magnitude and the rate of change of the input signals. The rod direction command signal is determined by the positive or negative value of the temperature difference signal. The rod speed and rod direction command signals are fed to the rod control system.

7.3.2.1 **Control Rod Assembly Arrangements**

There are 48 control rod assemblies (Section 3.3). The rods are divided among control and shutdown banks. There is a total of 16 control rod assemblies in the two shutdown banks. There are four control banks containing eight control rod assemblies each. The only control rod assemblies that can be manipulated under automatic control are the control rod assemblies in the control banks. Each control bank is divided into two groups to obtain smaller incremental reactivity changes per step. All control rod assemblies in a group are electrically paralleled to move simultaneously. There is individual position indication for each assembly.

7.3.2.2 **Rod Control**

7.3.2.2.1 Control Group Rod Control

The automatic rod control system maintains the average reactor coolant temperature by adjusting the positions of the control rod assemblies.

The rod control system is capable of restoring programmed average temperature following a change in load. The coolant average temperature can be maintained by automatic or manual rod insertion during load decrease transients and manually during load increase transients. The reactor coolant average temperature increases linearly from zero power to full power.

The control system will also initially compensate for reactivity changes caused by fuel depletion and/or xenon transients. Final compensation for these two effects is made by adjusting the boron concentration. The control system then readjusts the control group in response to changes in coolant average temperature resulting from changes in boron concentration.

The control rod assemblies are divided into two shutdown and four control banks, and each bank is divided into two groups, to follow load changes over the full range of power operation. Each group in a bank is driven by the same variable-speed rod drive control unit, which moves the groups sequentially one step at a time. The sequence of motion is reversible; that is, a withdrawal sequence is the reverse of the insertion sequence. The variable-speed sequential rod control affords the ability to insert a small amount of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband.

Manual control is provided to move a control bank in or out at a preselected fixed speed.

When the reactor power reaches approximately 15%, the operator may select the AUTOMATIC position, where the IN-HOLD-OUT lever is out of service and rod motion is controlled by the reactor control and protection systems. An interlock (P-2, Table 7.2-3) limits automatic control to reactor power levels above 15%. In the AUTOMATIC position, the rods are again inserted in a predetermined programmed sequence by the automatic programming equipment. However, rod withdrawal can only be performed manually. Manual rod withdrawal occurs in a predetermined sequence as discussed below.

Programming is set so that, as the first control bank out reaches a preset position near the top of the core, the second bank begins to move out simultaneously with the first bank. This staggered withdrawal sequence continues until the unit reaches the desired power level. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank out is the first control bank in.

With the simplicity of the rod program, the minimal amount of operator selection, and two separate direct position indications available to the operator, there is very little possibility that rearrangement of the control rod sequencing could occur.

7.3.2.2.2 Shutdown Banks Control

The shutdown banks of control rods, together with the control banks, are capable of shutting the reactor down. The shutdown banks are used in conjunction with the control banks to provide shutdown margin of at least 1.77% following reactor trip, with the most reactive control rod in the fully withdrawn position for all normal operating conditions. The shutdown groups are manually controlled during normal operation and are moved at a constant speed. Any reactor trip signal causes them to fall into the core. They are fully withdrawn during power operation and are withdrawn first during start-up. Criticality is always approached by withdrawing the control groups after withdrawal of the shutdown groups.

7.3.2.2.3 Interlocks

Measurements of turbine first-stage pressure provide indication when outside of the automatic control range below 15% of nominal power (P-2, Table 7.2-3). The manual controls are further interlocked with measurements of nuclear flux and delta T to prevent approach to an overpower condition (P-1).

7.3.2.3 **Rod Drive Performance**

7.3.2.3.1 Control Rod Assemblies

The control banks are driven by a sequencing, variable-speed rod drive programmer. In a control bank of assemblies, control groups (each containing a small number of assemblies) are moved sequentially in a cycle so that all groups are maintained within one step of each other. The sequence of motion is reversible; that is, the withdrawal sequence is the reverse of the insertion sequence. The sequencing speed is proportional to the control signal from the reactor control system. This provides control group speed control proportional to the demand signal from the control system. A rod drive mechanism control center is provided to receive sequenced signals from the programmer and to actuate switches in series with the coils of the rod drive mechanisms. Two reactor trip breakers are placed in series with the supply for the coils. To permit on-line testing, a bypass breaker is provided across each of the two trip breakers.

The power for the entire complement of control and shutdown rod drive mechanisms is provided by a system composed of two ac motor-generator sets. The sets consist of squirrel cage induction motors driving synchronous alternators.

The total capacity of the system, including the overload capability of each motor-generator set, is such that a single set out of service does not cause limitations in rod motion during normal plant operation. In order to minimize reactor trip as a result of a unit malfunction, the power system is normally operated with both units in service.

Figure 7.3-3 shows the power supply to the rod control equipment and control rod drive mechanisms. The power supply connections from the reactor trip breakers to the rod control equipment are in protective enclosures and are sized to handle 1000A. The minimum current required to hold the control rods is approximately 150A. A failure in this power supply bus downstream of the trip breakers that results in an open circuit or short circuit would be detected by the dropping of the rods. There are no other power sources in the reactor trip breaker switchgear or the rod control equipment with sufficient capacity to hold a control rod assembly in position in the event that it became crossed with the trip breaker output bus and the trip breakers were tripped.

Flywheels on the motor-generator sets and high-speed regulators on each unit enable the rods to ride through a complete loss of ac power for one second during electrical transients.

7.3.2.3.2 Rod Position Indication

Two separate systems are provided to sense and display control rod position, as described below:

1. Analog system - An analog signal is generated by measuring the position of each control rod assembly. This is accomplished by means of a linear position transmitter.

   An electrical coil stack is placed above the stepping mechanisms of the control rod magnetic jacks external to the pressure housing.

   When the associated control rod is at the bottom of the core, the magnetic coupling between a primary and secondary is small, and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is obtained.

   Direct, continuous readout of every control rod assembly position is presented to the operator by redundant rod position flat panel displays.

   The individual analog rod position signals are fed to the plant computer system for monitoring and readout. A deviation monitor alarm is actuated if any rod differs in its measured position from its group step demand position by a preset value. The alarm will reflash in the event of subsequent rod deviations which exceed the preset value. When reactor power is below 50%, the preset deviation values are increased. However, the increased limits may not be utilized for more than one hour in the previous 24 hours prior to increasing power above 50%. When reactor power is less than 50%, the amount of time in the past 24 hours that the increased deviation limits have been utilized will be tracked by the computer. The deviation monitor alarm also indicates bank sequence errors and when any shutdown bank has inappropriately left its fully withdrawn position.

   A rod bottom condition for each rod is indicated on the redundant rod position flat panel displays.

2. Digital system - The digital system counts pulses generated in the rod drive control system programmer. One counter is associated with each group of control rod assemblies. Readout of the digital system is in the form of electromechanical add-subtract counters reading the number of steps of demanded rod position with one display for each group. These readouts are mounted on the control panel.

The digital and analog systems are separate systems; each serves as backup for the other. Operating procedures require the reactor operator to compare the digital and analog readings upon recognition of any apparent malfunction. Therefore, a single failure in rod position indication does not in itself lead the operator to take erroneous action in the operation of the reactor.

7.3.2.4 **Primary System Pressure Control**

Reactor coolant system pressure is controlled by the use of the pressurizer. Inside the pressurizer water and steam are maintained at saturation temperature and pressure by electrical heaters and water spray. The electrical immersion heaters are located near the bottom of the pressurizer. The pressurizer has five heater groups comprised of one proportional heater group and four (backup) heater groups.

The pressurizer pressure control is normally operated with the proportional heater group in automatic. Each group of the backup heaters can be operated in standby or manually energized. When all backup heater groups are in standby, the proportional heater group is used to control small pressure variations due to heat losses, including losses due to a small continuous spray. The spray nozzle is located in the top of the pressurizer. A small continuous spray flow is maintained to reduce thermal stresses and maintain uniform water chemistry. Any backup heater groups that are in standby will automatically energize when the pressurizer pressure controller signal drops below a given value, or when pressurizer level rises above a given value.

Operation with one or more backup heater groups manually energized will result in an increase in pressure controller signal. Additional spray is automatically initiated when the pressure controller signal is above a given setpoint. The spray rate increases proportionally with increasing pressure, until it reaches a maximum value. Steam condensed by the spray reduces the pressurizer pressure. Adequate spray flow exists to maintain pressure when all of the backup heaters are energized. A continuous spray is maintained automatically, in equilibrium with the heat output of the energized backup heaters. Operation in this configuration allows stable pressure control. It reduces thermal stresses and thermal shock, by avoiding thermal stratification in the surge line. It also allows a rapid equalization of boron concentration between the pressurizer and the RCS.

Two power-operated relief valves limit system pressure for large load reduction transients. Spring-loaded safety valves limit system pressure following a complete loss of load without direct reactor trip or turbine bypass.

7.3.2.5 **Pressurizer Level Control**

The water inventory in the reactor coolant system is maintained by the chemical and volume control system. During normal unit operation, the pressurizer level is controlled by the charging-flow controller, which controls the charging-flow control valve to produce the flow demanded by the pressurizer-level controller. The pressurizer water level is programmed as a function of coolant average temperature. The pressurizer water level decreases as the load is reduced from full load. This is the result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes. To permit manual control of pressurizer level during start-up and shutdown operations, the charging-flow control valve can be manually regulated from the control room.

7.3.2.6 **Secondary System Control**

A review of the effects of the power uprate to a core power of 2587 MWt was conducted and the control systems and instrumentation were found to be adequate. The secondary system includes the steam generators and the condensate and feedwater systems.

The main steam, condensate, and feedwater systems are shown on Reference Drawings 1, 2, and 3.

All equipment is designed with highly reliable components. Maximum use is made of solid-state components in the electronic instruments; spring-loaded diaphragm control valves are employed to fail safe on loss of air or power.

All instrumentation and controls, where possible, are installed outside of the containment structure and in locations accessible for inspection and maintenance. Automatic control instruments in selected systems are provided with backup manual control through transfer switches. Alarms are provided to warn of abnormal conditions.

7.3.2.6.1 Turbine Steam Dump

The purpose of the steam dump valve system is to reduce reactor coolant system transients following a substantial turbine load reduction by dumping main steam directly to the condenser, thereby maintaining an artificial load on the steam generators. The control rod system can then reduce the reactor power to a new equilibrium value without causing overtemperature and/or overpressure conditions.

Following a reactor and turbine trip, sensible heat stored in the reactor coolant is removed without actuating the steam generator safety valves by means of a controlled steam dump to the condenser and by injection of feedwater to the steam generators. Reactor coolant system temperature is reduced to the no-load condition. This no-load coolant temperature is maintained by steam dump to the condensers, which removes residual heat.

The steam dump control system is designed to relieve steam from the steam generators to the condenser, to reduce the sensible heat in the primary system in the event of complete load rejection down to auxiliary load, and to maintain the steam generator pressure during hot standby conditions.

The turbine steam dump capacity was designed to be 40% of full-load steam flow at full-load steam pressure, all of which flows to the main condenser via the steam dump lines. For the measurement uncertainty recapture (MUR) power uprate, the steam dump capacity was reviewed for a bounding NSSS power of 2609 MWt. It was determined that the steam dump capacity could be as low as 28.7% of the steam flow rate corresponding to 2609 MWt NSSS power. Since this result was less than the 40% design criterion, the NSSS control system margin-to-trip analyses was reviewed. It was determined that there was acceptable margin to all relevant reactor trip setpoints for a 50% load rejection from 2609 MWt NSSS power.

When a load rejection occurs, if the change in the required program temperature of the reactor coolant system differs from the actual average temperature by more than a predetermined amount, a signal will actuate that portion of the steam dump system needed to reach the new program temperature.

The required number of steam dump valves choke or modulate full open, depending upon the magnitude of the temperature error signal upon receiving a loss-of-load signal. The dump valves can be modulated after they are full open by the reactor coolant average temperature signal.

The turbine steam dump flow reduces proportionally as the control rods act to reduce the average reactor coolant temperature. The artificial load is therefore removed as the reactor coolant average temperature is restored to its programmed equilibrium value.

7.3.2.6.2 Steam Generator Water Level Control

Each steam generator is equipped with a three-element feedwater controller (Figure 7.2-13) that maintains a programmed water level as a function of load on the secondary side of the steam generator. The three-element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the water level signal, and the steam flow signal, which is compensated by steam pressure signal. The steam generators are operated in parallel, both on the feedwater and on the steam side.

Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor coolant following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature or when the respective steam generator level rises to a given value.

Following a turbine trip, the main feedwater valves are closed on low T_{avg}. This provides an optimum heat sink. Subsequently, the operator remotely controls the feedwater regulating bypass valves to maintain the steam generator water level. Manual override of the feedwater control system is available at all times.

7.3.2.6.3 Turbine Control

The turbine control system is designed to regulate the steam flow to the turbine as a function of load or speed.

7.3.3 Design Evaluation

7.3.3.1 **Unit Stability**

The rod control system is designed to limit the amplitude and the frequency of continuous oscillation of reactor coolant average temperature about the control system setpoint within acceptable values. Continuous oscillation can be induced by the introduction of a feedback control loop with an effective loop gain that is either too large or too small with respect to the process transient response, i.e., instability induced by the control system itself. Because stability is more difficult to maintain at low power under automatic control, no provision is made to provide automatic control below 15% of full power.

The control system is designed to operate as a stable system over the full range of automatic control throughout core life.

7.3.3.2 **Step Load Changes Without Steam Dump**

A typical power control requirement is to restore equilibrium conditions, without a trip, following a ±10% step change in load demand, over the 15% to 100% power range for automatic control. With the automatic control rod withdrawal function disabled, manual control rod withdrawal will be required to restore equilibrium conditions following a 10% step increase in load. The design must necessarily be based on conservative conditions, and a greater transient capability is expected for actual operating conditions. A load demand greater than full power plus a small tolerance band is prohibited by the turbine control load limit devices.

The function of the control system is to minimize the reactor average coolant temperature deviation during the transient within a given value, and to restore average temperature to the programmed setpoint within a given time. The coolant average temperature can be maintained by automatic or manual rod insertion during load decrease transients and manually during load increase transients. Excessive pressurizer pressure variations are prevented by using spray and heaters in the pressurizer.

The margin between the overtemperature delta T setpoint and the measured delta T is of primary concern for step load changes. This margin is influenced by nuclear flux, pressurizer pressure, average reactor coolant temperature, and temperature rise across the core.

7.3.3.3 **Loading and Unloading**

Ramp loading and unloading of 5% per minute can be accepted over the 15% to 100% power range under manual control for loading and automatic or manual control for unloading without tripping the unit. The function of the control system is to maintain the reactor coolant average temperature as a function of turbine-generator load. The minimum control rod speed provides a sufficient reactivity insertion rate to compensate for the reactivity changes resulting from the moderator and fuel temperature changes.

The coolant average temperature increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The heaters limit the resulting system pressure decrease. The pressurizer level is programmed so that the water level is above the setpoint at which the heaters cut out during the loading and unloading transients. The primary concern during loading is to limit the overshoot in average coolant temperature and to provide sufficient margin in the overtemperature delta T setpoint.

The automatic load controls are designed to safely adjust the unit generation to match load requirements within the limits of the unit capability and warranted power.

7.3.3.4 **Loss of Load With Steam Dump**

The reactor control system is designed to accept 50% load rejection without trip. No reactor trip or turbine trip should be actuated for load losses in this range. The automatic turbine steam dump system is able to accommodate this abnormal load rejection and to reduce the effects of this transient imposed upon the reactor coolant system. The reactor power is reduced at a rate consistent with the capability of the rod control system. Reduction of the reactor power is automatic down to 15% of full power. The steam dump flow reduction occurs as fast as the control rod assemblies are capable of inserting negative reactivity.

The pressurizer relief valves might be actuated for the most adverse conditions, e.g., the most negative Doppler coefficient, and the minimum incremental rod worth. The relief capacity of the power-operated relief valves is sized large enough to limit the system pressure to prevent actuation of high-pressure reactor trip for the above conditions.

7.3.3.5 **Turbine-Generator Trip With Reactor Trip**

Whenever the turbine-generator unit trips at an operating level above 10% power, the reactor also trips. The unit is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the saturation temperature corresponding to the steam generator pressure at the safety valve setpoint. The thermal capacity of the reactor coolant system is greater than that of the secondary system, and because the full-load average temperature is greater than the no-load steam temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power. This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of cold feedwater to the steam generators.

The steam dump system is controlled from the reactor average coolant temperature signal, whose setpoint values are reset upon trip to the no-load value. Actuation of the steam dump must be rapid, to prevent actuation of the steam generator safety valves. With the steam dump valves open, the average coolant temperature starts to reduce quickly to the no-load setpoint. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam that is dumped.

Following the turbine trip, the steam voids in the steam generator will collapse, and the fully opened feedwater valves will provide sufficient feedwater flow to restore water level in the downcomer. The feedwater flow is cut off when the average coolant temperature decreases below a given temperature value or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator level while ensuring that the reactor coolant temperature is at the desired value. Residual heat removal is maintained by the steam generator pressure controller (manually selected), which controls the amount of steam flow to the condensers. This controller operates the same steam dump valves to the condensers that are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. The pressurizer water level is programmed to match as near as possible the level changes as a result of coolant temperature changes and so that the water level is above the setpoint at which the heaters are turned off on low pressurizer level. If heaters become uncovered following the trip, the chemical and volume control system will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

The steam dump and feedwater control systems are designed to prevent the average coolant temperature from falling below the programmed no-load temperature following the trip to ensure adequate reactivity shutdown margin.

7.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-064A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 1
	11548-FM-064A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 2
2.	11448-FM-067A	Flow/Valve Operating Numbers Diagram: Condensate System, Unit 1
	11548-FM-067A	Flow/Valve Operating Numbers Diagram: Condensate System, Unit 2
3.	11448-FM-068A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 1
	11548-FM-068A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 2

Figure 7.3-1
SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEM

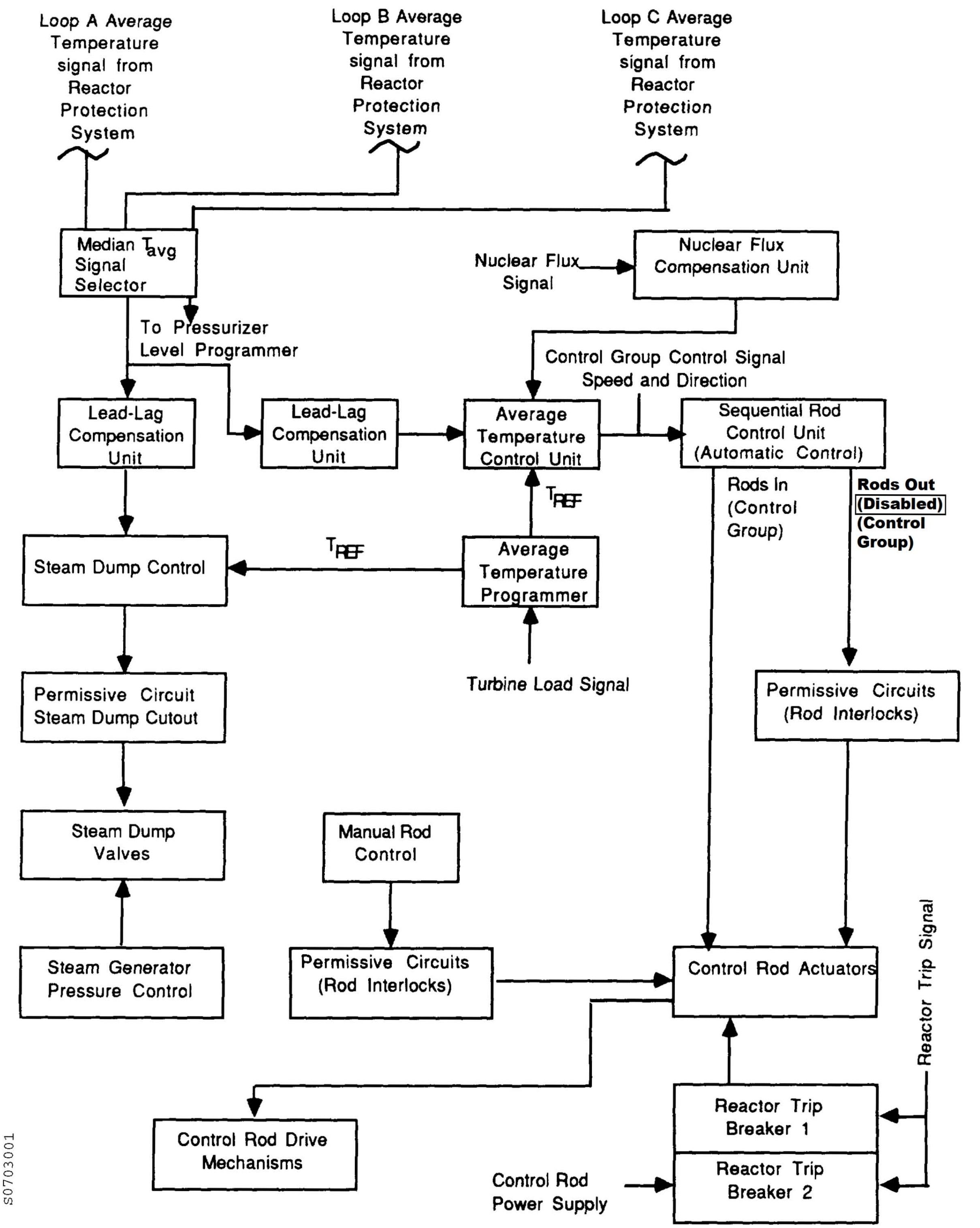
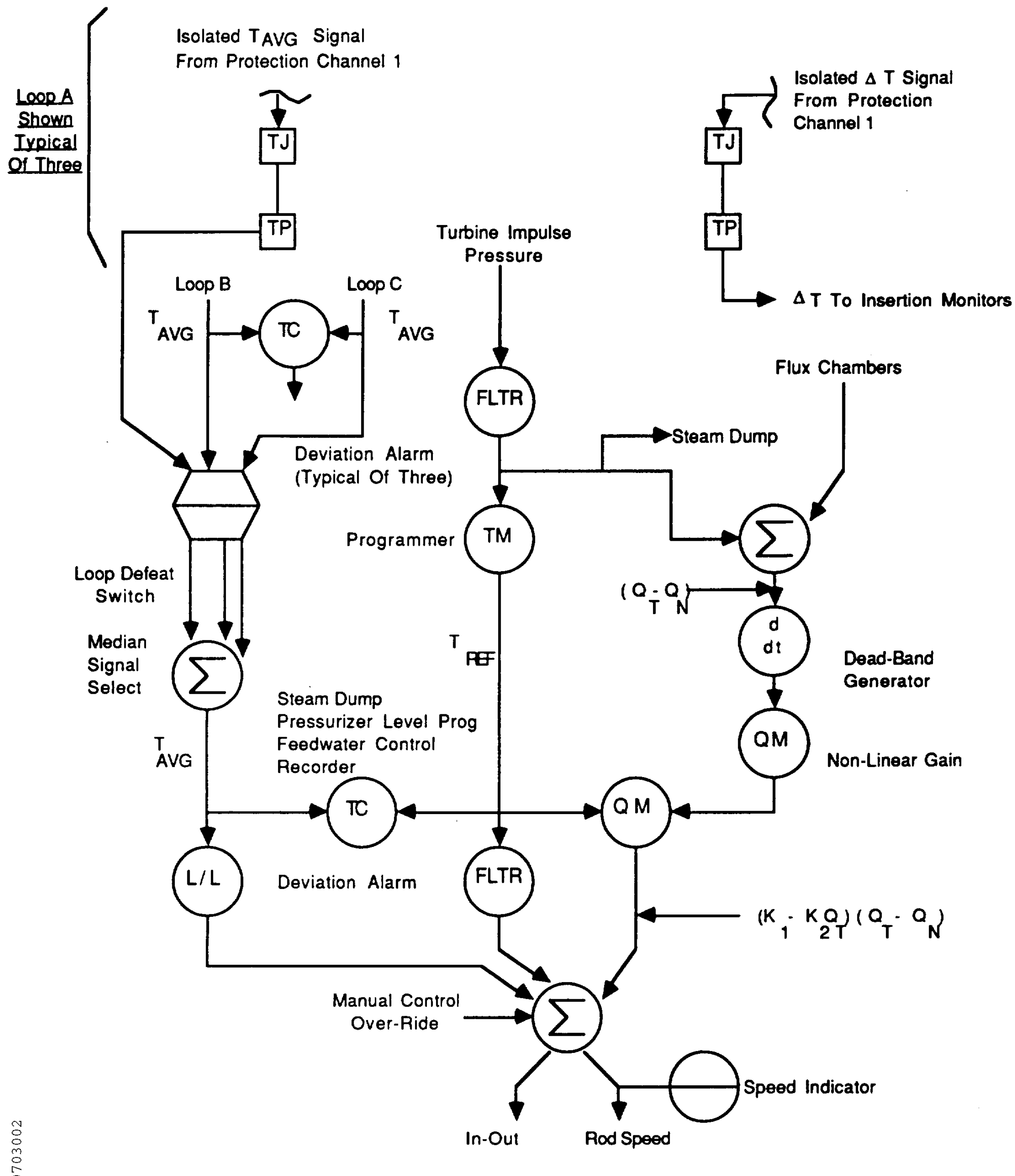
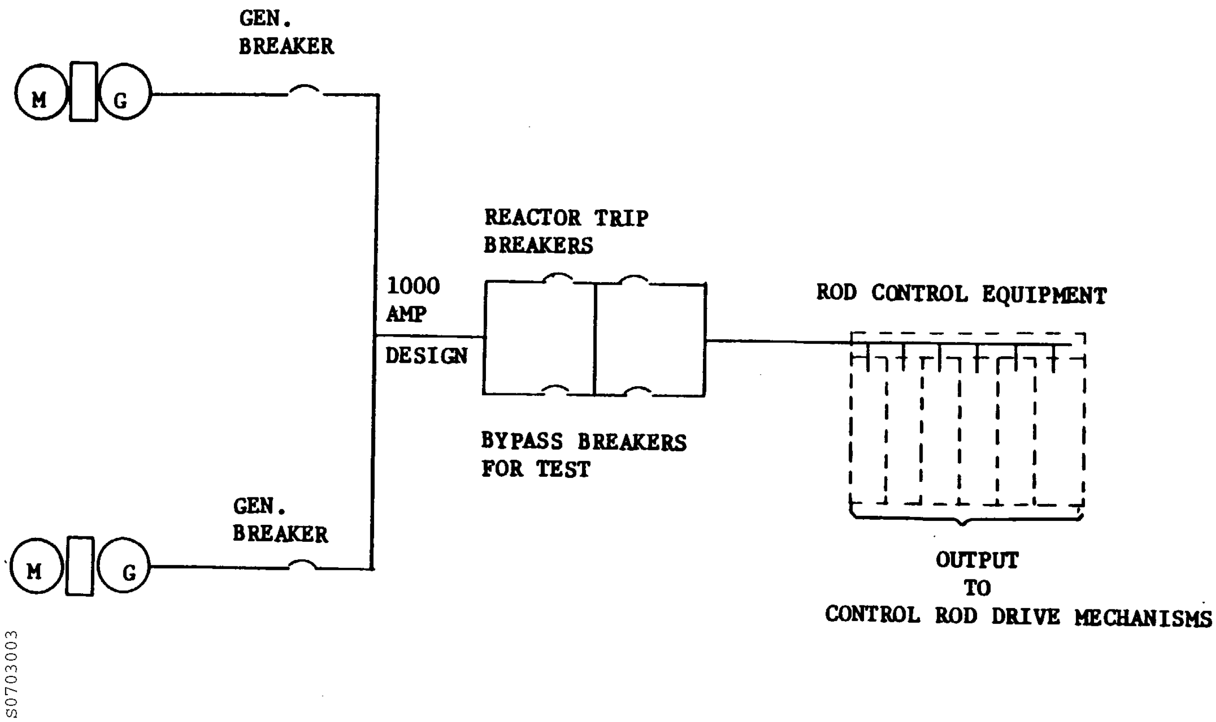


Figure 7.3-2
T_{avg} CONTROL SYSTEM



See Table 7.2-2 for Symbol Legend

Figure 7.3-3
POWER SUPPLY TO CONTROL ROD EQUIPMENT AND CONTROL ROD DRIVE MECHANISMS



7.4 NUCLEAR INSTRUMENTATION SYSTEM

7.4.1 Design Bases

7.4.1.1 Fission Process Monitors and Controls

The Nuclear Instrumentation System is used primarily for reactor protection. It permits monitoring of neutron flux and generates appropriate trip and alarm functions for various phases of reactor operating and shutdown conditions. It also provides a secondary control function, and indicates reactor status during start-up and power operation. Ex-core neutron flux detectors were added to meet R.G. 1.97 and Appendix R requirements. These are discussed in Section 7.10. The nuclear instrumentation system uses information from the three separate types of instrumentation channels to provide three discrete protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection from source to the intermediate and low power ranges. As the reactor power increases, the overpower protection level is increased (administratively) after satisfactory higher-range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Several types of neutron detectors, with appropriate solid-state electronic circuitry, are used to monitor the leakage neutron flux from a completely shut down condition to 120% of full power. The power range channels are capable of recording overpower excursions up to 200% of full power.

The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary. The lowest range (source range) covers six decades of leakage neutron flux.

The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This is generally greater than one count per second. The next range (intermediate range) covers approximately eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation (power range) covers slightly more than two decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range (the intermediate range monitors go off-scale at any point greater than 70% of rated power based on the core loading pattern). The overlap for all detector ranges is shown in Figure 7.4-1 in terms of leakage neutron flux. Start-up-rate indication for the source and intermediate range channels is provided at the control console and on the nuclear instrumentation panel.

The system described above provides control room indication and recording of reactor neutron flux during core loading, shutdown, start-up, and power operation, as well as during subsequent refueling. Reactor trip and rod-stop control and alarm signals are provided by this system for safe plant operation. Control and permissive signals are transmitted to the reactor control and protection system for automatic plant control. Equipment failures and test status information are annunciated in the control room.

7.4.2 System Description

The nuclear instrumentation system (Figure 7.4-2) consists of eight independent channels: two of these are the source range, two are the intermediate range, and four are the power range channels. In addition, there are three auxiliary channels: the visual-audio count rate channel, the comparator channel, and the start-up-rate channel. The various detectors associated with the eight primary channels are shown in relative position with respect to the core configuration on Figure 7.4-3.

7.4.2.1 **Protection Philosophy**

Nuclear unit protection assurance, is obtained from the three ranges of ex-core nuclear instrumentation. Separation of redundant protective channels is maintained from the neutron sensor with its associated cables to the signal conditioning equipment in the control room with its associated output wiring, indicating or recording devices, and protective devices. Where redundant protective channels are combined to provide non-protective functions, the required signals are derived through isolation amplifiers. These devices are designed so that open or short-circuit conditions, as well as the application of 120V ac or 140V dc to the isolated side of the circuit will have no effect on the input or protective side of the circuit. As such, failures on the non-protective side of the system will not affect the individual protection channels. Redundant channels are powered from independent power sources, each channel being provided with the necessary power supplies for its detectors, signal conditioning equipment, trip bi-stables, and associated trip relays. The nuclear instrumentation channels are mounted in four separate racks to provide the necessary physical separation between redundant channels.

The overpower protection provided by the ex-core nuclear instrumentation consists of three discrete levels. Continuation of start-up operation or power increase requires a permissive signal from the higher-range instrumentation channels before the lower-range level trips can be manually blocked by the operator.

A one-out-of-two intermediate-range permissive signal (P-6, Table 7.2-3) is required prior to source range level trip blocking and detector high-voltage cutoff. Source range level trips are automatically reactivated and high voltage restored when both intermediate range channels are below the permissive (P-6) level. There are provisions for administratively reactivating the source range level trip and detector high voltage if required. Source range level trip block and high-voltage cutoff are automatically maintained by the same power range permissive (P-10), which permits blocking of the intermediate range and power range (low range) flux level trips.

The intermediate range level trip and power range (low range) level trip can only be blocked after satisfactory operation and permissive information are obtained from two out of four power range channels. Individual blocking switches are provided so that the power range (low range) trip and intermediate range trip can be independently blocked. These trips are automatically reactivated when any three of the four power range channels are below the permissive (P-10) level, thus ensuring automatic activation of more restrictive trip protection.

Blocking of any reactor trip function is indicated by the control board permissive status lights. Channels that provide reactor unit protection through one-out-of-two or one-out-of-four logic matrices are equipped with positive detent-type trip-bypass switches to enable channel testing. The trip-bypass condition for individual channels is indicated at the control board and at the nuclear instrumentation racks. The reactor unit protection afforded by the highest-setpoint, power range trip is never blocked or bypassed.

7.4.2.2 **Source Range Instrumentation**

Two independent source range channels are provided. Each receives pulse-type signals from a proportional counter. The preamplified detector signal is received by the source range instrumentation conditioning equipment located in the control room racks. The detector signal, which is a random count rate proportional to leakage neutron flux, is conditioned for conversion to an analog signal proportional to the logarithm of the neutron flux count rate.

The isolated analog signals from each channel are sent to various recording and indicating devices to provide the operator with necessary start-up information. Bi-stable units also located in the racks are used to generate alarms and reactor trip signals. Trip signals from the bi-stables are transmitted to relays in the protection relay racks, where the necessary logic involved in generating reactor trip signals is performed.

An isolated count-rate signal derived from either channel is connected to a scaler-timer. This same signal also feeds the audio count-rate channel, which provides an audible count-rate signal, proportional to the neutron flux. Speakers are provided both in the containment and in the control room. Start-up-rate indication is also provided for each source range channel. These signals are generated from the isolation amplifier output, since there is no protection function involved.

7.4.2.3 **Intermediate Range Instrumentation**

Two independent, compensated ionization chambers provide extended flux coverage from the upper end of the source range to any point greater than 70% of rated power based on core loading patterns. The equipment for each channel, including the high-voltage and compensating voltage power supplies, are located in separate drawers. To maintain separation between these redundant channels, the drawers are mounted in separate racks. The signal conditioning equipment furnishes an analog output voltage proportional to the logarithm of the neutron flux spectrum. Each channel covers approximately eight decades of leakage flux. Isolation amplifiers (for start-up-rate circuits, remote recording, remote indication, etc.) and bi-stable amplifiers (for permissives, rod-stop, and reactor trip) use this analog voltage to indicate plant status and provide the necessary plant protection functions. All relays associated with plant control or protection are located in the logic or auxiliary relay racks.

7.4.2.4 **Power Range Instrumentation**

Four dual-section, uncompensated ionization chambers are used for power range flux detection. Each chamber provides two current signal outputs (one from each section) to signal conditioning equipment in the control room racks. Each chamber has an independent high-voltage power supply. The individual current signals obtained from each section of the detector are proportional to upper-core and lower-core neutron flux, respectively. These provide core flux status information at the instrument racks and, through isolation amplifiers, provide the same information at the control console. A separate output furnishes bias signals used in the overpower and overtemperature delta T reactor trip functions. The individual current signals are combined to provide an average signal proportional to average core flux in the associated core quadrant. This average signal is conditioned to provide an analog voltage signal for use in permissive, control, and protection bi-stable amplifiers.

Isolation amplifiers, which provide remote control signals and core power status information to the operator and plant computer system (PCS), also utilize the average power analog signal. The four power range channels are operated from separate ac sources and are housed in separate racks so that a single failure will not cause loss of protection functions. Redundant relays for the protection functions are located in the logic portion of the protection system.

Isolated analog outputs from each power range channel are compared in a separate auxiliary channel drawer. This comparator provides the operator with annunciation of deviations in average power between the four power range channels. Switches are provided to defeat this comparison for a failed channel so that subsequent deviations or failures among the three remaining channels are annunciated.

7.4.2.5 **Equipment Design**

The ex-core nuclear instrumentation system consists of various plug-in-type modules that perform the functions indicated on Figure 7.4-2 for the source, intermediate, and power ranges. Components designed to military specifications are used, where possible, in conjunction with a conservative design stressing reliability, derating of components and circuits, and the use of field-proven circuits. On-line testing and calibration features are provided for each channel. The test signals are superimposed on the normal sensor signal during plant operation. This permits valid trip conditions to override the test signal, unless the sensing element is disconnected from the circuit for maintenance activities.

7.4.3 Components

7.4.3.1 Detectors

The nuclear instrumentation system employs six detector radial locations containing a total of eight detectors (two proportional counters, two compensated ionization chambers, and four dual-section, uncompensated ionization chamber assemblies) installed around the reactor in the primary shield. Windows in the primary shield minimize leakage flux attenuation and distortion.

Boron fluoride proportional counters having a nominal thermal neutron sensitivity of 10 counts/neutron/cm^2/sec (cps/nv) provide pulse signals to the source range channels. These detectors are installed on opposite “flat” portions of the core at an elevation approximating the quarter-core height.

Compensated ionization chambers serve as neutron sensors for the intermediate range channels, and are located in the same instrument wells and detector assemblies as the source range detectors. These detectors have a nominal thermal neutron sensitivity of 4×10^{-14}A/n/cm^2/sec. Gamma sensitivity is less than 3×10^{-11}/Roentgen/hr when operated uncompensated, and is reduced to approximately 3×10^{-13}A/R/hr in compensated operation. The detectors are positioned at an elevation corresponding to the center of the quarter-core height.

The detector assemblies containing one each of the above-mentioned detectors use watertight, corrosion-resistant, steel enclosures. High-density polyethylene, used as a moderator-insulator within the detector assemblies, will be confined at temperatures associated with a LOCA. The detectors are connected to the junction box at the bottom of the detector well by special high-temperature, radiation-resistant cables.

The remaining four detector assemblies contain the power range ionization chambers. Each provides two current signals corresponding to the neutron flux in the upper and lower sections of a core quadrant. These detectors have a total neutron sensitive length of 10 feet and a nominal thermal neutron sensitivity for each section of 1.7×10^{-13}A/n/cm^2/sec. Gamma sensitivity of each section is approximately 10^{-10}A/R/hr.

The detector assemblies for power range operation are installed vertically and located equidistant from the reactor vessel at all points, and, to minimize neutron flux pattern distortions, within one foot of the reactor vessel. Cabling from individual detector wells to the containment penetrations and to the instrument racks in the control room is routed in individual conduits, with physical separation between the penetrations and conduits associated with redundant protective channels.

7.4.3.2 Source Range Components

The source range output information is tabulated in Table 7.4-1. The detector for each source range channel is a Boron-10 lined proportional counter. The signal received from the counter has a range of 1 to 10^6 pulses per second randomly generated, and is received through a fixed gain pulse preamplifier located outside the containment. The preamplifier optimizes the signal-to-noise ratio and also furnishes high-voltage coupling to the detector.

The preamp has internal provisions for generating self-test frequencies of 10 counts per second (cps) and 10.24 kcps. These test oscillator circuits are energized by a switch located on the associated source range drawer. The source range channel power supplies furnish low voltage for preamp operation as well as low voltage for the drawer-mounted modules. The preamp is solid-state in design, with discrete components, and includes an impedance matching network between the preamp output and the 75-ohm triaxial or superscreen cable.

The preamp output is received at the postamplifier located on the source range drawer. This module provides amplification and discrimination, both of which are adjustable. Discrimination is provided between neutron flux pulses and combined noise and gamma-generated pulses. The discriminator supplies two outputs: one output (isolated) to a scaler-timer unit on the visual-audio channel drawer (see source range auxiliary equipment), and the other to a pulse shaper (transistorized flip-flop circuit) that supplies a constant amplitude pulse to the log integrator module within the source range drawer.

Logarithmic integration of the pulse signal is performed in another modular unit to obtain an analog dc signal. The log signal is then amplified for local indication on the front panel of the source range drawer, and is also delivered through a parallel run to the source range level bi-stables and isolation amplifier. The analog output signal is proportional to the count rate being received from the sensor, and is displayed by the front panel meter on a scale calibrated logarithmically from 10^0 to 10^6 cps. The solid-state isolation amplifier provides five analog outputs, all of which are adjustable through attenuator controls. Three outputs are used as follows: as remote indication (0−1 ma); as remote recording (0−37.5 mV dc); and as an input to the PCS (0−5V dc). A 0−10V dc output is used by the start-up-rate amplifier to produce a start-up-rate indication at the main control board. The remaining output (0−5V dc) is a spare.

All bi-stables employ a basic plug-in module with the external wiring determining the mode of operation (latching or non-latching) and direction of output change with rising power. Bi-stables have two adjustments: “Trip Level” and “Differential.” The first adjustment determines the trip point of the bi-stable, while the second determines the “dead zone” difference between the trip and release points of the bi-stable. The bi-stable module card includes a relay driver circuit made up of a silicon-controlled rectifier and full-wave bridge configuration. The bi-stable output controls are the silicon-controlled rectifier gate, which, in turn, controls conduction of the full-wave bridge supplying the power to drive up to four 115V ac Westinghouse BF relays. Relays are located remote from the nuclear instrumentation system racks.

Of the three bi-stables monitoring the source range level amplifier signal, one is a spare, one is used to monitor shutdown flux level only, and the third monitors source range operation during shutdown and start-up operation and provides a reactor trip on high flux level. The reactivity of the core during shutdown is monitored by a bi-stable to ensure protection of plant personnel working in the containment. Bi-stable tripping will initiate local visual and audible annunciation and remote audible annunciation of any abnormal increase in core activity. Visual annunciation occurs at the nuclear instrumentation system rack and on the main control board. Audible annunciation is handled by the annunciator located in the control room, and the evacuation horn located in the containment.

These annunciators ensure that plant personnel are alerted to any potentially hazardous condition. This bi-stable action is manually blocked by deliberate operator action during plant start-up. Blocking is continuously annunciated at the control board during source range operation and is automatically blocked by permissive P-6. The bi-stable trip point is approximately one-half decade above the flux level recorded during full shutdown.

The source range level bi-stable monitors the core reactivity during the full span of source range operation, until such time as the intermediate range channels assume control of that portion of the reactor protection that is being supplied by nuclear instrumentation. At that time, when the intermediate range permissive P-6 is available, the source range reactor trip bi-stable may be manually blocked, and high voltage removed from the B10 detector by the operator's actuation of two momentary-contact switches located on the main control board.

A fourth bi-stable-relay driver unit is used as a high-voltage failure monitor. Loss of this voltage actuates the bi-stable, the relay driver, and then the associated relay. The relay provides control board annunciation through a one-out-of-two matrix formed with a similar relay controlled by the other source range channel. Failure of either source range high voltage actuates this common annunciator on the main control board. During normal operation, the source range high voltage will be cut off (as described above) when manual block of the source range trips is initiated. In this instance, loss of high-voltage annunciation will be intentionally defeated to prevent the alarming of a condition that is not abnormal.

A test-calibrate module is also included in each source range drawer for self-check of that particular channel. A multiposition switch on the source range front panel controls this module and also the operation of the built-in oscillator circuits in the preamp. The module is capable of injecting test signals of either 60, 10^3, 10^5 or 10^6 cps at the input to the post amplifier, or a variable dc voltage corresponding to 1 to 10^6 cps at the input to the log amplifier. An interlock between the trip bypass switch and the test-calibrate switch will prevent inadvertent actuation of the reactor trip circuits, (i.e., the channel cannot be put in the test mode unless the trip is defeated). Trip bypass will be annunciated on the source range drawer and on the main control board, per IEEE 279 Standard, Section 4.13. Operation of the test-calibrate module will be annunciated on the control board as "Nuclear Instrumentation System Channel Test." This common annunciator for all nuclear instrumentation system channels is alarmed when any channel is placed in the test position, and alerts the operator that a test is being performed at the nuclear instrumentation system racks.

7.4.3.3 **Source Range Auxiliary Equipment**

7.4.3.3.1 Visual-Audio Count Rate

The visual-audio count rate receives a signal from each of the source range channels. This isolated signal originates at the discriminator output in each source range channel. A switch on the audio count-rate drawer selects either source range channel for monitoring. The selected signal is fed to a scaler-timer unit that permits count accumulation in the preset time or preset count mode. A visual display to five decimal places is presented through counting strips located on the front of the audio count-rate drawer.

A “Scale Factor” switch permits division of the scaler output signal by 10, 100, or 1000. This signal, derived from the printer output of the scaler, is conditioned and sent to two of the audio amplifiers, which power two speakers: one speaker located in the control room, and the other in the containment. These speakers give personnel an audible indication of the count rate. Since the audio amplifier signal is taken from the coded scaler output, adjustment of the scale factor switch will alter only the audible count rate. This enables the operator to maintain the audible count rate at a distinguishable level.

7.4.3.3.2 Remote Count-Rate Meter

The remote meter indication is an analog signal proportional to the count rate being received, and is obtained from the 0 to 1 mA isolation amplifier output.

The meter is mounted on the main control board and calibrated logarithmically from 10^0 to 10^6 cps. This meter gives the same indication at the control board as is displayed by the local meter on the corresponding source range drawer.

7.4.3.3.3 Remote Recorder

This recorder is capable of continuously recording the nuclear instrumentation system channels. Each channel is directly connected to the multipen recorder. In the case of the source ranges, a 0 to 37.5 mV dc signal, proportional to the count rate range of 10^0 to 10^6 cps, is supplied for recording during source range operation.

7.4.3.3.4 Start-up-Rate Circuitry

The start-up-rate drawer receives four input signals (0−10V dc), one from each of the source and intermediate range channels. Four rate amplifier modules condition these signals and output four rate signals to the respective control room start-up-rate meters. A test module is provided that can inject a test signal into any one of the rate circuits, and can be monitored on a test meter mounted on the front panel of this drawer. Two power supplies are provided to ensure rate indication from at least one source and intermediate range channel pair.

7.4.3.4 **Intermediate Range Components**

Intermediate range output information is tabulated in Table 7.4-2. Each intermediate range channel receives a direct current signal from a compensated ion chamber, and supplies positive high voltage and compensating (negative) high voltage to its respective detector. The compensating high voltage is used to cancel the effects of gamma radiation on the signal current being delivered to the intermediate range channel. Both high-voltage supplies will be adjustable through controls located inside the channel drawer. The detector signal is received by the intermediate range logarithmic amplifier. The modular unit, comprising several operational amplifiers and associated discrete solid-state components, produces an analog voltage output signal that is proportional to the logarithm of the input current. This signal is used for local indication and is monitored by the isolation amplifier and the various bi-stable relay-driver modules within the intermediate range drawer. A 10^{-11}A signal is continuously inserted, and serves as a reference during gamma compensation. Local indication is provided by a meter mounted on the front panel of the drawer, which has a logarithmic scale calibration of 10^{-11} to 10^{-3}A.

The isolation amplifier is the same solid-state module that is used in the source range; it supplies the same five outputs for the same usage. Six bi-stable relay-driver units are used in the intermediate range drawer to provide the following functions:

1. One monitors the positive high voltage.
2. One monitors the compensating high-voltage.
3. One provides the permissive P-6.
4. One provides rod-stop (blocks manual rod withdrawal).
5. One provides reactor trip.
6. One serves as a spare.

The intermediate range permissive P-6 bi-stable drives two Westinghouse BF relays (for redundancy), and the relays from each channel are combined in one-out-of-two matrices to provide the permissive function and control board annunciation of permissive availability. Permissive P-6 permits simultaneous manual blocking of the source range trips, and removal of the source range detector high voltage. Once source range blocking has been performed, the operator may, through administrative action, defeat permissive P-6 and reactivate the source range high-voltage and trip functions if required. This defeat is accomplished by the coincident operation of two control-board-mounted, momentary-contact switches. This provision, however, is only operational below permissive P-10, which is supplied by the power range channels. Above P-10, the defeat circuit is automatically bypassed and permissive P-6 is maintained which, in effect, maintains source range cutoff. The level bi-stable relay-driver unit that provides the intermediate range rod-stop function also drives two Westinghouse BF relays. Again, one-out-of-two matrices formed by the relays from the two intermediate range channels supply the rod-stop function and control board annunciation. Blocking of the outputs of these matrices is administratively performed when nuclear power is above permissive P-10, and can only be accomplished by deliberate operator action on two control-board-mounted switches.

The intermediate range reactor trip function is provided by a similar circuit arrangement, the only difference being the trip point of the bi-stable units. The same control board switches that control blocking of the rod-stop matrices also provide blocking action for the reactor trip matrices. These blocks are manually inserted when the power range instrumentation indicates proper operation through activation of the P-10 permissive function. On decreasing power, however, the more restrictive intermediate range trip functions are automatically reinserted in the protective system. While these trips are blocked, there will be continuous illumination on the main control board of "Intermediate Range Trip and Rod Stop Blocked." The high-voltage failure monitors provide both local and remote annunciation upon failure of the respective high-voltage supplies. A common "Intermediate Range Loss of Detector Voltage" and separate "Intermediate Range Loss of Compensate Voltage" are provided as control board annunciators for the intermediate ranges.

Administrative testing of each intermediate range channel is provided by a built-in test-calibrate module that injects a test signal at the input to the log amplifier. The signal is controlled by a multiposition switch on the front of each intermediate range drawer. A fixed 10^{-11}A signal is available, along with a variable 10^{-10} through 10^{-3}A signal, selectable in decade increments.

As in source range testing, the test switch on the intermediate range must be operated in coincidence with a trip bypass on the drawer. An interlock between these switches prevents injection of a test signal, until the trip bypass is in operation. Removal of the trip bypass also removes the test signal.

7.4.3.5 **Intermediate Range Auxiliary Equipment**

7.4.3.5.1 Remote Meter

The remote meter indication is in the form of an analog signal (0–1 mA) proportional to the ion chamber current. The isolation amplifier in each channel supplies this output to a separate meter. Meter calibration is 10^{-11} to 10^{-3}A.

7.4.3.5.2 Remote Recorder

This is the same recorder described above for the source range. A 0 to 50 mV dc signal from the isolation amplifier is supplied to the recorder and is proportional to the ion chamber current range of 10^{-11} to 10^{-3}A. All the intermediate range signals are connected to the recorder.

7.4.3.6 **Power Range Components**

The power range output information is tabulated in Table 7.4-3. The power range detector is a long, uncompensated ion chamber assembly consisting of two separate neutron-sensitive sections. Each section supplies a current signal to the associated power range. There is one high-voltage power supply per channel that supplies voltage to both sections of the associated detector. The two signals are received at the channel input and handled through separate shunt, filter board assemblies. There is a meter range/rate switch for each digital ammeter located on the front panel of the power range drawer. Each meter range/rate switch has four positions, namely 400µA/slow, 4000µA/slow, 400µA/fast, and 4000µA/fast. The switch selects shunt resistors for the meter but never interrupts the ion chamber signal to the power range channel. The circuit is so designed that a failure of the meter or switch will not interrupt the signal to the average power circuitry.

The individual currents are displayed on the two front ion chamber current meters and are then sent to separate isolation amplifiers. There are two isolation amplifiers monitoring each of the two individual current signals. The unit feeding the delta T protection function is being used for its impedance-matching characteristics rather than isolation. All of the isolation amplifiers are capable of providing the same five output ranges as the isolation amplifiers previously described in relation to the source and intermediate ranges. Two of the isolation amplifiers (used as impedance matching networks), one monitoring each of the currents, supply signals to the delta T reset. The other two isolation amplifiers provide output for the remote recorder, remote meter, and PCS. The individual current signals are then sent to a summing amplifier module that outputs a linear 0 to 10V dc signal proportional to their average. The output of this unit will feed a linear amplifier with two controls: one a “Zero” adjust located on the module itself, the other a “Gain” adjust with a calibrated dial located on the drawer’s front panel. The output signal from this unit corresponds to 0% to 120% of full power and is displayed on a percent full-power meter on the front panel of the power range drawer. This same signal is delivered directly to three isolation amplifiers, a dropped-rod sensing assembly, and six bi-stable relay-driver modules. These isolation amplifiers are identical to those previously described, and the outputs are the same in number and range but are used in different functions. (Specific outputs from the amplifiers are discussed in the auxiliary equipment section that follows.)

The dropped-rod sensor assembly is an operational amplifier unit that incorporates an adjustable lag network at one input and a non-delayed signal on the other. The unit compares the actual power signal with the delayed power signal received through the lag network, and amplifies the difference. This amplified differential signal is delivered to a bi-stable relay-driver unit that trips when the level of this signal exceeds a preset amount. Tripping of this unit indicates a power level change over the lag period, which would be indicative of a dropped rod. This bi-stable unit is a latching type, ensuring that the necessary action will be initiated and carried to completion. Specifically, the unit controls dual Westinghouse BF relays which, in one-out-of-four logic matrices, provide a control board annunciation signal, and a PCS input signal. A reset switch on the associated power range drawer must be operated manually to reset the bi-stable.

The bi-stable units that sense the power level signal, as derived by the linear amplifier, are non-latching and perform the following functions: (1) overpower rod-stop (blocks manual rod withdrawal); (2) permissive functions; (3) low-range reactor trip; and (4) high-range reactor trip.

The overpower rod-stop and permissive bi-stables are units that trip on high power level and control Westinghouse BF relays in the remote relay racks. The rod-stop relay matrices (one-out-of-four) provide a rod-stop function to the rod control system and a main control board annunciation. Two-out-of-four logic, developed by relays controlled through the respective power range bi-stables, provide the signals required for the permissive functions. One set of relays provides permissive P-10, as previously discussed regarding its use in the source range and intermediate range. One set of relays provides permissive P-8, as previously discussed in Section 7.2.2 regarding low reactor coolant flow trips. One other group of relays is provided as a spare.

Permissives P-8 and P-10 are supplied solely by nuclear instrumentation. For this reason, the nuclear instrumentation design provides for main control board annunciation of P-8 and P-10 availability. Permissive P-10 is used in all three ranges of nuclear instrumentation, while P-8 is provided by nuclear instrumentation for use in the reactor protection system.

The low-range trip bi-stable actuates two Westinghouse BF relays in the logic system. The two relays provide redundance within the logic portion of the protection system. Each relay is used in a separate matrix with the relays from the other power range channels to continue the redundancy. The logic circuitry formed by the contacts on these relays provide for one-out-of-four and two-out-of-four logic outputs. The low-range trip relays provide the following functions: (1) PCS input (single channel); (2) low-range trip annunciation (two-out-of-four coincidence); (3) reactor trip signal to reactor protection system (two-out-of-four coincidence); and (4) annunciation of “Single Channel Low-Range Trip” (one-out-of-four).

Provisions for manually blocking the low-range trip become available when two-out-of-four power ranges exceed the permissive P-10 level. Operator action on two control-board-mounted momentary-contact switches then initiates the blocking action. A control board permissive status light, “Power Range Low-Range Trip Blocked,” will be illuminated continuously when the trip function is blocked. On decreasing power, three of four power ranges below the P-10 power level will automatically reactivate the low-range trip.

The high-range reactor trip logic circuitry is developed identical to the low-range reactor trip circuitry, but no provision for blocking is included. The high-range trip remains active at all times to prevent any continuation of an overpower condition.

An additional bi-stable unit monitors the high-voltage power supply in the power range. Operation of this unit is identical to that for the source and intermediate ranges. The bistable provides relay actuation in the remote relay racks on failure of power range high voltage. While there is a separate relay for each power range, they control a common “Power Range Loss of Detector Voltage” annunciator on the main control board. Separate local indication of high-voltage failure is provided on the power range drawers.

The test-calibrate module provided on each power range is capable of injecting test signals at several points in the channel. In all cases, the test signals are superimposed on the normal signal. A bypass of the dropped-rod circuit is not required during channel test since this circuit produces only an alarm through one-out-of-four logic matrix for a sudden power change. Test signals can be injected independently or simultaneously at the input of either ammeter-shunt assembly to appear as the individual ion chamber currents. Operation of the test-calibrate switch on any power range will cause the "Channel Test" annunciator to be alarmed on the main control board.

7.4.3.7 **Power Range Auxiliary Equipment**

7.4.3.7.1 Comparator

The comparator receives an isolated signal from each of the four power range detectors. These signals are conditioned in separate operational amplifier circuits and then compared with one another to determine if a preset amount of deviation of power levels has occurred between any two power ranges. Should such a deviation occur, the comparator output will operate a remote relay to actuate the control board annunciator, "Power Range Channel Deviation." This alarm will alert the operator to either a power unbalance being monitored by the power ranges, or to a channel failure. Through other indicators, the operator can then determine the deviating channel(s) and take corrective action. Should correction of the situation not be immediately possible (e.g., a channel failure, rather than reactor condition), provisions are available to eliminate the failed channel from the comparison function. The comparator can then continue to monitor the active channels.

7.4.3.7.2 Remote Recorder

Each power range channel supplies a 0 to 50 mV dc signal proportional to 0-120% full power to the nuclear power recorder. The signals from Power Ranges Number 1, Number 2, Number 3, and Number 4 are connected directly to the recorder. All four signals are continually indicated on control board meters.

7.4.3.7.3 Remote Meter

The remote meters receive the 0 to 1 mA isolated output that is available from each power range. This indication corresponds to that shown on the power range drawer. The signal is displayed on a meter scale calibrated from 0 to 120% of full power.

7.4.3.7.4 Overpower Recorders

A pair of recorders is used to monitor the individual average power indications from the four power ranges. Each recorder provides continuous monitoring of two power range channels, and has a full-scale deflection time of 0.25 second. The recorders are capable of displaying overpower excursions up to 200% of full power. A power range isolated output of 0-50 mV dc will correspond to the range of 0 to 200% full power for these recorders.

7.4.3.7.5 Ion Chamber Current Recorders

A recorder is provided to record the upper and lower ion chamber currents for each power range detector. Two isolated outputs (0−5V dc), one from each of the ion chamber isolation amplifiers, are provided for each recorder. Comparison of the two traces is an indication of the flux difference between the upper and lower sections of a given detector.

7.4.3.7.6 Delta Flux Remote Meter

Four control-board-mounted meters display the flux difference between the upper and lower ion chambers directly for each of the power range detectors.

7.4.3.8 **Miscellaneous Control and Indication Panel**

Switches are provided on this panel to permit a failed power range channel's overpower-rod-stop function to be bypassed, and its overpower-rod-stop signal to the rod control system to be supplied by signals derived from active channels. This allows normal power operation to continue while the failed channel is repaired.

Two panel mounted indicating lights, one for the upper section of the core and one for the lower section of the core are provided and are illuminated for a deviating condition or for a failed power range detector. Each power range detector provides an upper and a lower flux signal corresponding to the neutron flux in the upper section and in the lower section of a core quadrant. These upper and lower flux signals are compared and alarm the following conditions:

1. A high deviation of any upper section from the average of all the upper sections.
2. A high deviation of any lower section from the average of all the lower sections.

High deviation alarms will occur, one for the upper section and one for the lower section, when any individual section is greater than a preset amount above the average. These alarms warn the operator that a quadrant power tilt exists when the power level is above 50% power. The alarm circuits are automatically defeated when all sections are below 50% of rated power.

Additionally, two panel mounted indicating lights, one for each deviation comparison, are illuminated when all sections are below 50% of rated power.

In the event of a failed power range channel, bypass switches located on the panel are provided to defeat a failed power range channel input to an upper or lower section deviation comparison. This feature permits the continued monitoring of the core with a power range channel out of service.

7.4.3.9 **Output Information**

Tables 7.4-1, 7.4-2, and 7.4-3 provide the nuclear instrumentation system control and indication output information for the source, intermediate, and power ranges, respectively.

7.4.4 System Evaluation

7.4.4.1 Philosophy and Setpoints

During plant shutdown and operation, three discrete, independent levels of nuclear protection are provided from the three ranges of ex-core nuclear instrumentation. The basic protection philosophy is that the level protection is present in all three ranges to provide a reliable, rapid, and restrictive protection system that is not dependent upon operation of higher-range instrumentation.

Reliability is obtained by providing redundant channels that are physically and electrically separated. Fast trip response is an inherent advantage of using level trip protection in lieu of start-up-rate protection (with a long time constant) during plant start-up. More restrictive operation is an inherent feature, since an increase in power cannot be performed until satisfactory operation is obtained from higher-range instrumentation, which permits administrative bypass of the lower-range instrumentation. On decreasing power level, protection is automatically made more restrictive. Start-up accidents while in the source range are rapidly terminated without significant increases in nuclear flux, and with essentially no power generation or reactor coolant temperature increase.

The indications and administrative actions required by this protection system are readily available to the operator and should result in a safe, uncomplicated increase of power.

7.4.4.2 Reactor Trip Protection

During reactor start-up, the operator is made aware of satisfactory operation of one or more intermediate range channels by annunciation (audible and visual) at the control board. The source and intermediate range flux level information is also readily available on recorders and indicators at the control console. At this time, if both intermediate range channels are functioning properly, the operator would depress the two manual block switches associated with the source range logic circuitry, thus causing cutoff of source range detector voltages and blocking the trip logic outputs. The manual block should not be initiated, however, until at least one decade of satisfactory intermediate range operation is obtained. The permissive P-6 annunciation is continuously displayed by the control board status lights.

Continuation of the start-up procedure in the intermediate range would result in a normal power increase and the receipt of a permissive signal from the power range channels when two out of four channels exceed 10% of full power. The operator is alerted to this condition by a control board permissive status light. Indicators (one per channel) and a recorder also indicate unit status in terms of percent full power. If the operator does not block the intermediate range trip and continues the power increase, a rod stop will automatically occur from either of the intermediate range channels. The operator should depress the momentary “Manual Block” push-buttons associated with the intermediate range rod stop and reactor trip logic. This would transfer protection to the low-range trips for the four power range channels. The permissive P-10 status light would be continuously displayed, as was P-6. The two low-range manual block switches must be depressed to initiate blocking prior to continuation of the power increase. The permissive functions associated with administrative trip blocking and automatic reactivation are provided with the same separation and redundancy as the trip functions.

When power operation is decreasing to lower levels, more restrictive trip protection is automatically afforded when three out of four power range channels are below permissive P-10, and when two out of two intermediate range channels are below the permissive P-6.

7.4.4.3 **Rod-Drop**

An additional alarm function provided by the power range instrumentation is backup to the rod-drop detection of the rod bottom bi-stables on the rod position system. The nuclear instrumentation rod-drop detection is provided by comparison of the average nuclear power signal with the same signal, as conditioned by an adjustable lag network. This method provides a response to dynamic signal changes associated with a dropped-rod condition, but does not respond to the slower signal changes associated with normal plant operation. Main control room alarm actuation from at least one of the four power range channels will occur for any dropped-rod condition.

Each rod-drop sensing circuit has associated with it a bi-stable amplifier driving two relays in separate logic relay racks. The logic relay matrices are connected in a one-out-of-four “OR” configuration to initiate a control room alarm. The dropped rod detection circuit also illuminates the dropped rod window on the individual NIS rack that detected the dropped rod.

7.4.4.4 **Control and Alarm Functions**

Various control and alarm functions are obtained from the three ranges of ex-core nuclear instrumentation during shutdown, start-up, and power operation. These functions are used to alert the operator to conditions that require administrative action, and alert personnel to unsafe reactor conditions. They also provide signals to the rod control system for automatic blocking of rod withdrawal during plant operation to avoid unnecessary reactor trips.

7.4.4.4.1 Source Range

No control functions are obtained from the source range channels. Alarm functions are provided, however, to alert the operator of any inadvertent changes in shutdown reactivity. Visual annunciation of this condition is at the control board, with audible annunciation in the containment and control room. This alarm can either be blocked before start-up or can serve as the start-up alarm in conjunction with administrative procedures.

7.4.4.4.2 Intermediate Range

Both alarm and control functions are supplied by the intermediate range channels. Blocking of rod withdrawal is initiated by either intermediate range channel on high flux level. This condition is alarmed at the control board to alert the operator that rod stop has been initiated. In addition, the intermediate range actuates the P-6 permissive status light when either channel exceeds the P-6 permissive level. This alerts the operator to the fact that he must take administrative action to manually block the source range trips to prevent an inadvertent trip during normal power increase.

7.4.4.4.3 Power Range

The power range channels provide alarm and control functions similar to those in the intermediate range. An overpower rod-stop function from any of the four power range channels inhibits rod withdrawal and is alarmed at the control board. The power range channels also actuate the P-10 permissive status light when two of the four channels exceed the permissive P-10 level. As in the case of P-6 in the intermediate range, this alerts the operating personnel that administrative action (namely, blocking of intermediate and low-range trips) is required before any further power increase may take place.

A permissive status light is provided for P-8, “Nuclear Power Below P-8.” The extinguishing of the P-8 permissive status light alerts the operator that the one-out-of-three low-flow trips and one-out-of-three pump-breaker-open trips are now active. These trips are blocked while the status light is illuminated. Additional functions are provided in the power range of operation. A dropped control rod will be sensed by one or more of the power range channels, and this condition will initiate an alarm on the main control room annunciator and illuminate a dropped rod window on the individual NIS rack that detected the dropped rod.

Another function is a power range channel deviation alarm. This alarm is furnished by the comparator channel through a comparison of the average power level signals being supplied by the power range channels. Actuation of this alarm alerts the operator to a power imbalance between the channels so that corrective action can be taken. Additionally, two signals, supplied through isolation amplifiers, are provided by each power range channel: one signal is used for the upper section deviation alarm and one signal is used for the lower section deviation alarm. Actuation of these alarms alerts the operator to a power imbalance between the detector upper or between the detector lower sections so that corrective action can be taken. These ion chamber signals are discussed in Section 7.4.3.8.

In the case of a failed channel, defeat switches are provided to defeat a channel’s input to the channel deviation comparison as well as the detector section deviation comparisons.

7.4.4.5 **Power Supply**

The nuclear instrumentation system draws its primary power from the vital instrument buses, whose reliability is discussed in Chapter 8. Redundant nuclear instrumentation system channels are powered from separate buses. The loss of a single vital instrument bus would result in the initiation of all reactor trips associated with the channels deriving power from that source. During power operation, the loss of a single bus would not result in a reactor trip, since the power range reactor trip function operates from two-out-of-four logic. If the bus failure occurred during source or intermediate range operation (one-out-of-two logic), a reactor trip condition would result.

7.4.4.6 **Safety Factors**

The relation of the power range channels to the reactor protection system has been described in Section 7.2. To maintain the desired accuracy in trip action, the total error from drift in the power range channels will be held to ±1.0% at full power. Routine tests and calibration will ensure that this degree of deviation is not exceeded. Bi-stable trip setpoints of the power range channels will also be held to an accuracy of ±1.0% of full power.

Table 7.4-1
SOURCE RANGE SIGNALS

Signal and Source	Destination and/or Function
Isolation amplifier	
0–10V dc	Auxiliary channel start-up rate (SUR)
0–5V dc	PCS
0–5V dc	Spare
0–1 mA dc	Remote meter counts per second (cps)
0–37.5 mV dc	Remote recorder
Bistable amplifiers	
115V ac	Miscellaneous process relay rack (spare)
115V ac	Miscellaneous process relay rack (high flux level at shutdown)
115V ac	Reactor protection relay rack (source range reactor trip)
115V ac	Miscellaneous process relay rack (annunciate "source range loss of detector voltage")
Manual block	
115V ac	Miscellaneous process relay rack (block high flux level at shutdown)
Trip bypass	
115V ac	Reactor protection relay rack (block of source range reactor trip)
Test-calibrate	
115V ac	Relay rack (nuclear instrumentation system channel test - control room)
Discriminator	
$1–10^6$ Cps	Source range auxiliary channel (visual-audio)

Table 7.4-2
INTERMEDIATE RANGE SIGNALS

Signal and Source	Destination and/or Function
Isolation amplifier	
0–10V dc	Auxiliary channel start-up rate
0–1 mA dc	Remote meter (A)
0–50 mV dc	Remote recorder
0–5V dc	Spare
0–5V dc	PCS
Bistable amplifiers	
115V ac	Relay rack (spare)
115V ac	Reactor protection relay rack (intermediate range permissive P-6)
115V ac	Miscellaneous process relay rack (intermediate range rod stop)
115V ac	Reactor protection relay rack (intermediate range reactor trip)
115V ac	Miscellaneous process relay rack (annunciate “intermediate range loss of detector voltage”)
115V ac	Miscellaneous process relay rack (annunciate “intermediate range loss of compensating voltage”)
Trip bypass	
115V ac	Reactor protection relay rack (block of rod-stop and reactor trip)
Test-calibrate	
115V ac	Miscellaneous process relay rack (NIS channel test - control room)

Table 7.4-3
POWER RANGE SIGNALS

Signal and Source	Destination and/or Function
Isolation amplifier (ion chamber A)	
0–10V dc	Upper flux comparator
0–5V dc	PCS
0–1 mA dc	Remote meter (delta flux)
0–5V dc	Remote recorder
0–50 mV dc	Spare
Isolation amplifier (ion chamber A)	
0–10V dc	Delta T overpower-overtemperature compensation
Isolation amplifier (ion chamber B)	
0–10V dc	Lower flux comparator
0–5V dc	PCS
0–1 mA dc	Remote meter (delta flux)
0–5V dc	Remote recorder
0–50 mV dc	Spare
Isolation amplifier (ion chamber B)	
0–10V dc	Delta T overpower-overtemperature compensation
Isolation amplifier (average power)	
0–10V dc	Spare
0–5V dc	PCS
0–1 mA dc	Remote meter (% of full power)
0–50 mV dc	Remote recorder
0–5V dc	Spare
Isolation amplifier (average power)	
0–10V dc	Power mismatch
0–5V dc	Spare
0–1 mA dc	Spare
0–50 mV dc	Spare
0–5V dc	Spare
Isolation amplifier (average power)	
0–10V dc	Comparator
0–5V dc	Spare
0–1 mV dc	Spare
0–50V dc	Overpower recorder
0–5V dc	Spare

Table 7.4-3 (CONTINUED)
POWER RANGE SIGNALS

Signal and Source	Destination and/or Function
<u>Bi-stable amplifiers</u>	
115V ac	Reactor protection relay rack (annunciator “NIS dropped rod flux decrease > 5% per 2 sec”)
115V ac	Miscellaneous process relay rack (overpower rod stop)
115V ac	Reactor protection relay rack (permissive P-8)
115V ac	Reactor protection relay rack (permissive P-10)
115V ac	Reactor protection relay rack (spare permissive)
115V ac	Reactor protection relay rack (low range reactor trip)
115V ac	Reactor protection relay rack (high range reactor trip)
115V ac	Miscellaneous process relay rack (annunciate “power range loss of detector voltage”)
<u>Test-calibrate</u>	
115V ac	Miscellaneous process relay rack (nuclear instrumentation system channel test - control room)
<u>Test bypass</u>	
115V ac	Miscellaneous process relay rack (NIS overpower rod stop bypass)

Figure 7.4-1
RANGES OF NIS INSTRUMENTATION

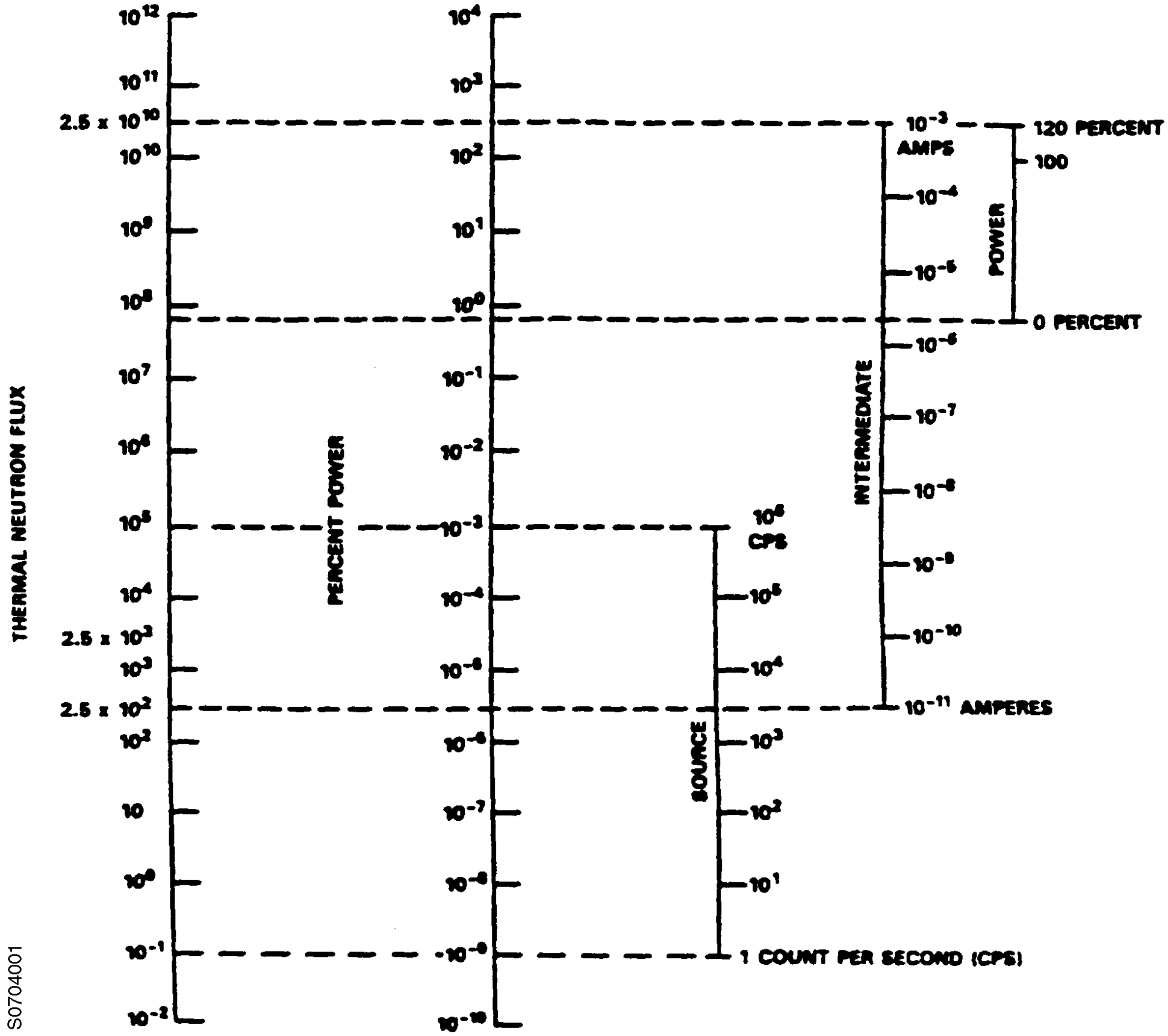


Figure 7.4-2
NUCLEAR INSTRUMENTATION SYSTEM

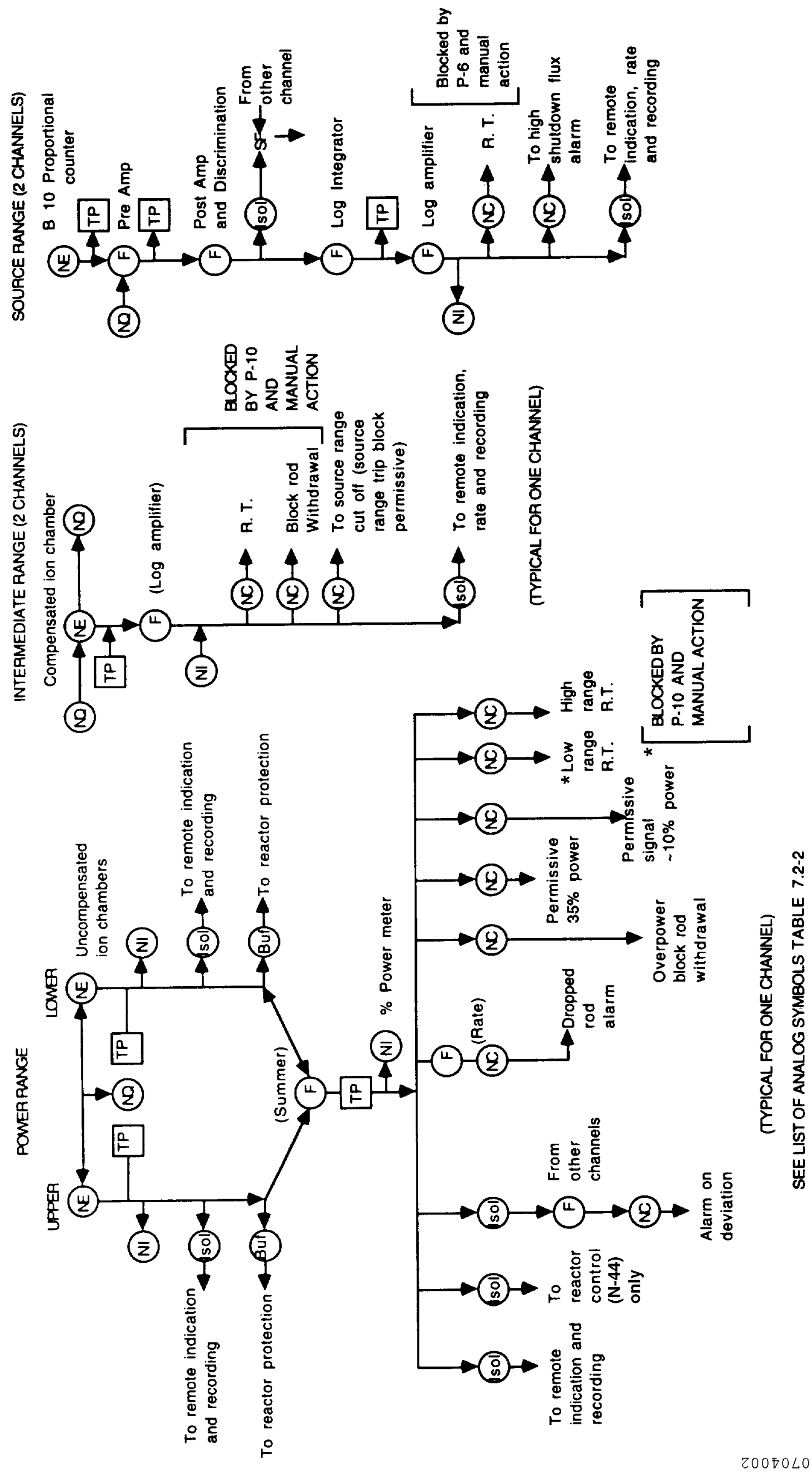
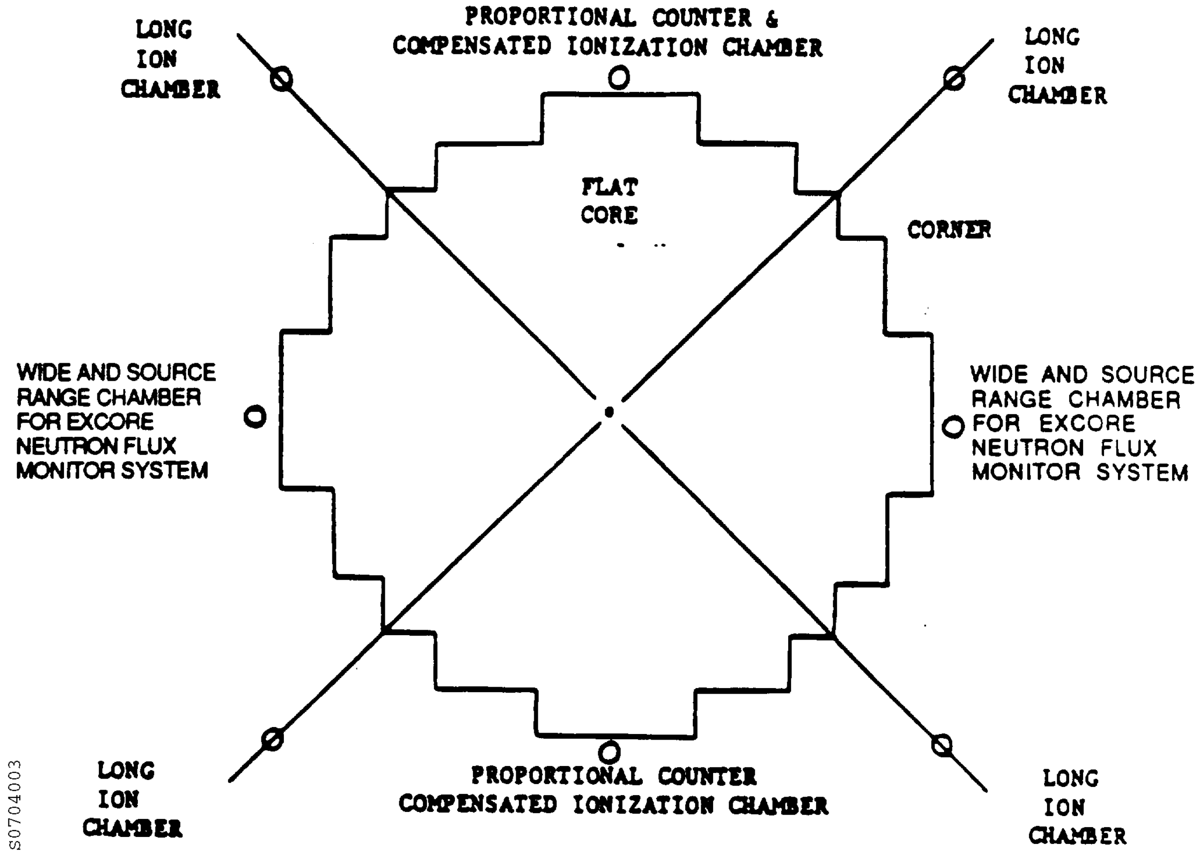


Figure 7.4-3
NEUTRON DETECTOR LOCATIONS



Intentionally Blank

7.5 ENGINEERED SAFEGUARDS

7.5.1 Design Bases

The engineered safeguards instrumentation measures temperatures, pressures, flows, and levels in the reactor coolant system, main steam system, reactor containment, and auxiliary systems. They actuate the engineered safeguards systems, and monitor their operation. Transmitted signals (flow, pressure, temperature, etc.) that can cause actuation of the engineered safeguards are either indicated or recorded in the control room.

The instrumentation and control systems provided to initiate the engineered safeguards systems are defined as safety-grade equipment and meet the safety standards applicable at the time of purchase and installation. Accident mitigation equipment subjected to a changing environment was evaluated in response to the NRC I&E Bulletin 79-01B (Reference 1) as described in Section 7.5.3.5.1.

Design criteria for redundancy and separation are similar to those used for the reactor protection system (Section 7.2). A list of emergency safeguards actuation functions is given in Table 7.5-1.

The engineered safeguards systems are actuated by the redundant logic and coincidence networks similar to those used for reactor protection. Each network actuates a device that operates the associated engineered safeguards equipment, motor starters, and valve operators. The channels are designed to combine redundant sensors, independent channel circuitry, and coincident trip logic. Where possible, different but related parameter measurements are utilized. This ensures a safe and reliable system in which a single failure will not defeat the intended function. The action-initiating sensors, bi-stables, and logic are shown in the figures included in the detailed engineered safeguards actuation instrumentation description given in Section 7.5.2. The engineered safeguards instrumentation system actuates (depending on the severity of the condition) the safety injection system, containment isolation, containment spray system, and the diesel-generators, and trips the containment vacuum system.

Availability of control power to the engineered safeguards trip channels is continuously indicated. The loss of instrument power to the sensors, instruments, or logic devices in the engineered safeguards instrumentation places that channel in the trip mode, except for containment spray initiating channels and the recirculation mode transfer (RMT) circuitry, which have been designed on an energize to operate basis. These systems were designed in this way to preclude their spurious operation on a loss of power.

The redundant batteries supplying power to the vital bus system are classified as passive components and are therefore subject to passive type failures. The definition of a passive failure is a failure which will not occur until after accident mitigation has entered the recirculation phase (post-RMT). Thus, should a LOOP/LOCA occur, the loss of a battery or dc bus will not credibly occur until after the unit enters the recirculation phase. This ensures the CLS Hi-Hi and RMT energize to actuate circuitry has power available during all credible design basis events.

The engineered safeguards systems are divided into protective safeguards and consequence limiting safeguards. The protective safeguards consist of the safety injection system. The consequence limiting safeguards include the spray system, containment isolation system, and the containment vacuum system. These systems are described in detail in Chapter 6. The control system logic diagrams for these safeguards are shown in Figures 7.5-1 and 7.5-2.

7.5.1.1 **Safety Injection**

Active safety injection components are actuated upon low-low pressurizer pressure, high containment pressure signals, high differential steam pressure between any steam lines and the main steam header, or high steam-line flow signals coincident with either low temperature average or low steam-line pressure signals. These actuating channel circuits are described in Section 7.2.

The signal that actuates safety injection low-low pressurizer pressure can be manually blocked when the pressurizer pressure reaches 2000 psig. This is only done during a controlled plant cooldown when the reactor is shut down. The signal that actuates safety injection on high containment pressure cannot be blocked and thus is available even when the low pressurizer pressure actuation signal is blocked. The purpose of the manual block of the signal on low pressurizer pressure is to prevent inadvertent safety injection actuation when the plant is being cooled down and depressurized.

A safety injection signal will isolate the feedwater lines by closing all control valves (main and bypass valves), trip the main feedwater pumps which in turn close the pump discharge valves, and thereby actuate the auxiliary feedwater system (Section 10.3.5), and will actuate the necessary valves required to allow the safety injection system to operate properly. Section 6.2 describes the safety injection system.

The passive accumulators of the safety injection system do not require signal or power sources to perform their functions. The actuation of the active portion of the engineered safeguards is from signals described in Table 7.2-1.

7.5.1.2 **Consequence Limiting Safeguards**

The consequence limiting safeguards system is operated by three signals: two initiation signals and one reset signal. The two initiation signals are the high containment pressure signal and the high-high containment pressure signal. The reset signal is the containment low-pressure signal. The high containment pressure signal is actuated when the containment pressure increases to a value in the range of 3.0 psig. The high-high containment pressure signal is actuated when the containment pressure increases to a value in the range of 8.3 psig. The containment low-pressure signal is actuated when the containment pressure is reduced to approximately atmospheric pressure after either a high containment pressure or high-high containment pressure signal.

The high containment pressure signal allows for a reactor shutdown without initiation of the spray system. This signal generates a safety injection signal. The high containment pressure signal also closes trip valves located in normally operating systems penetrating the containment that are not required to control the reactor coolant system pressure and containment pressure rise (Table 7.5-2).

The high-high containment pressure signal, indicating a LOCA, initiates the spray system and completes the containment isolation by actuating the remaining isolation trip valves.

The containment low-pressure signal indicates a return of the containment pressure to approximately atmospheric, and allows manual reset of the control circuits of the consequence limiting safeguards system.

Four pressure channels are connected to operate on a three-out-of-four basis, and are designed to operate on pressure increase. Each pressure channel sends a signal to two sets of redundant matrices, one set for the high containment pressure point and the other set for the high-high containment pressure point. Each of the two matrices in the high containment pressure matrix set sends a backup signal to initiate a safety injection, which in turn de-energizes the containment vacuum pumps and trips containment isolation valves. Each of the two redundant matrices in the high-high containment pressure matrix set operates one containment spray subsystem, one recirculation spray subsystem, trips containment isolation valves, and sends a backup signal to the electrical circuit that is normally actuated by one of the two redundant high containment pressure matrices. When three out of four signals of the correct value are received simultaneously from the pressure channels by a matrix, an initiation signal (either a high containment pressure signal or a high-high containment pressure signal) is emitted accordingly. When two out of four signals are received simultaneously from the pressure channels by a matrix indicating a return to low containment pressure, the initiation signal emitted by that matrix is canceled and the electrical circuit controlling the components operated by the matrix can be manually reset. The pressure channels are connected to the open taps of the leakage monitoring system outside the containment at a point before the pressure monitoring instrument (Section 5.3.2), and the containment isolation trip valves.

The safeguards design provides physically separated redundant components, and a capability to test devices used to derive a final output signal, in accordance with IEEE-279 requirements.

7.5.1.3 **Spray Subsystems**

Each redundant high-high containment pressure matrix emits a signal that actuates an electrical control circuit that operates one of the two redundant containment spray trains, and two of the four redundant recirculation spray trains. Each signal opens the appropriate motor-operated valves and starts a containment spray pump by supplying power to the electric motor for the pump.

In the case of the recirculation spray system, each CLS Hi Hi actuation circuit in conjunction with a RWST low level signal immediately starts an inside recirculation spray pump and initiates a two minute delayed start of the outside recirculation spray pump. The delay for starting the outside recirculation spray pump is sufficient to avoid overloading the EDG with high starting loads from two RS pumps.

The containment spray pumps may be stopped manually, after the control circuit controlling the pump has been manually reset. The control circuit can only be reset after a containment low-pressure signal is activated. Containment spray flow status is provided to the plant NUREG-0696 MUX system for remote display in the control room and other locations.

The recirculation spray system can also be stopped manually. The inside recirculation spray pumps can be stopped after the respective control circuits have been manually reset following a containment low-pressure signal. The outside recirculation spray pumps can be stopped at any time. This ability is necessary to control possible leakage in the suction and discharge piping (Section 6.3).

7.5.1.4 **Containment Vacuum System**

7.5.1.4.1 Normal Operation

The control system for the vacuum pumps compares an input signal of the containment air partial pressure with the actual containment air partial pressure, and provides for starting of the mechanical vacuum pumps if the actual containment air partial pressure is 0.1 psia greater than the desired input value. The containment air partial pressure may be varied between 9 and 10.3 psia depending upon the capability of the engineered safeguards to depressurize the containment within 60 minutes after a design-basis accident. Two redundant control channels are provided to operate the containment vacuum pumps. Each vacuum pump is operated through a three-position HAND-OFF-AUTO switch to permit either manual or automatic vacuum pump start. Either redundant control channel can actuate either containment vacuum pump. If the switch is in the OFF position, and the containment air partial pressure is greater than 0.1 psia above the setpoint, an alarm will alert the operator in the control room to manually start a vacuum pump, using the HAND position of the switch. If the switch is in the AUTO position, the alarm is received and a vacuum pump starts automatically. The actual partial pressure of air in the containment is not measured, but is obtained by subtracting the partial water vapor pressure signal from the containment total pressure signal.

The total containment pressure signal is measured in each channel by a pressure transmitter that transmits a signal functionally related to the actual containment total pressure. The partial water vapor pressure in the containment is derived by locating resistance temperature detectors, one for each channel, at the cooling coil outlet in each of three transition duct sections in the containment air recirculation system. The temperature measured in each transition duct is virtually saturated, and the sensed temperature is essentially the dewpoint temperature. The three temperature signals in each channel are transmitted to an auctioneer unit associated with the same channel, which selects the lowest temperature (lowest water vapor partial pressure condition). The temperature signal from the auctioneer in each channel is transmitted to an instrument that relates the temperature reading to a corresponding water vapor pressure, and transmits a signal functionally related to the water vapor partial pressure. The water vapor partial pressure signal and the total air pressure signal in each channel are sent to an instrument that subtracts the vapor partial pressure from the total air pressure, and transmits a signal functionally related to the partial air pressure. The value of partial air pressure desired in the containment is set on an instrument common to both channels and containing an adjustable setpoint mechanism, which transmits a signal functionally related to the desired partial pressure of air. The desired partial air pressure signal from the common instrument and the actual partial air pressure of each channel are compared. To eliminate the possibility of two different setpoints, a common instrument is used to set the desired partial air pressure in both channels.

When the actual containment air partial pressure increases 0.1 psia above the desired value, either channel of the control system energizes an electrical circuit that either sounds an alarm to signal the operator in the control room to manually start and operate a mechanical vacuum pump, or sounds the alarm and initiates starting and operating one mechanical vacuum pump directly, depending on the setting of the three-position switch in the control system. If the containment air partial pressure continues to increase, an alarm indicating that containment pressure is still rising is actuated. This alarm sounds when the partial containment air pressure has increased 0.20 psia above the desired containment air partial pressure. When the alarm is sounded in the control room, the operator initiates an orderly reactor shutdown in accordance with Technical Specifications.

When the actual containment air partial pressure falls 0.1 psia below the desired containment air partial pressure, the mechanical vacuum pump stops. If the pump does not stop, an alarm sounds.

The high-capacity steam jet air ejector is used to evacuate the containment before plant start-ups, and at other times is secured by administrative control.

7.5.1.4.2 Off-Normal Operation

The containment vacuum pumps are manually or automatically started in the event of a small rupture in the reactor coolant system piping. When the containment air partial pressure is 0.1 psia greater than the desired value, a containment vacuum pump automatically starts, or an alarm signals the operator to manually start a containment vacuum pump, depending on the setting of the three-position switch in the control system.

A small rupture in the reactor coolant piping will cause an increase in the vapor partial pressure in the containment, due to the mass of vapor added to the containment atmosphere by the flashed reactor coolant. Total pressure of the containment atmosphere will be further increased due to the heating of air in the containment resulting from energy released from the flashing reactor coolant in addition to the increase caused by the vapor partial pressure. The result is that total pressure will increase more rapidly than vapor pressure, which would be interpreted as an increase in the containment air partial pressure by the instrumentation provided to perform this calculation. Several measurements, as described in Section 7.5.1.4.1 are made to determine the air partial pressure. They are recorded in the control room.

An increase in temperature measured in each transition duct, and the vapor partial pressure derived from these temperature readings when the vacuum pump is started, could indicate a small rupture in the coolant system or main steam system within the containment. The operator would then take steps to determine the location of the leak, isolate it, and shut down the vacuum pump as required.

The option to operate the containment vacuum pumps automatically is provided in keeping with the overall plant concept of automatic control, since automatic operation of these pumps would not result in an excessive or uncontrolled release of radioactivity.

Alarms are provided to signal that pump operation is required and to signal that the containment pressure has continued to rise with a vacuum pump in operation. The only difference between the manual and automatic mode of operation is that, in the automatic mode, the vacuum pump automatically starts at the same time an alarm is sounded to signal that pump operation is required, whereas, in the manual mode, the pump must be started by the operator when the alarm sounds. In addition, in the automatic mode, the vacuum pump is shut down automatically if the containment air partial pressure continues to rise.

The alarm that signals that the containment pressure is still rising while the vacuum pump is operating is provided for both the manual and the automatic modes of operation. In the manual mode, the operator immediately takes over pump operation manually, determines the cause of the continual pressure rise in the containment, shuts off the vacuum pump if necessary, and also, if necessary, begins to initiate an orderly reactor shut down. In the automatic mode, the vacuum pump is automatically shut down when this alarm is initiated. Since this alarm and trip are set at 0.10 psia above the pressure that signals that pump operation is required (0.20 psia above the desired setpoint), the amount of radioactivity that will be released, even with a small rupture in the reactor coolant piping and with automatic pump operation, will be minor, since this incremental pressure increase will occur in a short period of time.

In addition to the alarms and trips described above, the containment vacuum pumps are disconnected from the automatic control circuits on actuation of a safety injection signal, i.e., the vacuum pumps receive a signal to shut down and the vacuum system isolation valve solenoids are de-energized.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The following discussion was the response to a request from the NRC during initial licensing to analyze the expected radioactive release from the containment in the event of a DBA and a small rupture in the reactor coolant system piping. Although the X/Q value used in the discussion is non-conservative compared to current standards, this analysis is considered bounded by the current large break LOCA dose analysis.

A small rupture in the reactor coolant system piping, assumed to be equivalent to a 2.6-inch-inside-diameter pipe, will cause the containment pressure to reach the high-pressure value in approximately four minutes. If the containment vacuum pumps are operating during the four-minute period before the pumps are de-energized and the isolation valves tripped, i.e., if the operator did not consider pump shutdown necessary when the alarm sounded to indicate continual containment pressure rise, then the expected radioactive release from the containment will be 0.288 Ci of Xe-133 equivalent and 0.00058 Ci of I-131 equivalent. This activity release is based on 1% failed fuel and equilibrium corrosion products in the reactor coolant. An unfiltered, uncontrolled release of this activity from the containment, χ/Q of 8×10^{-4} sec/m^3, and the assumption of a “puff” ground release, will result in a whole-body dose at the exclusion boundary of 0.01 mrem and a thyroid dose of about 0.25 mrem, both well below the limits suggested in 10 CFR 100. This incident is therefore not considered to be a hazard to the public.

The vacuum pump discharge passes through charcoal and particulate filters and the radiation monitors of the waste gas system before entering the environment. The particulate and charcoal filters further reduce the activity released. In addition, activity released to the environment in excess of the limits of 10 CFR 20 will be terminated by radiation monitors, which isolate the discharge of the containment vacuum pumps on high activity levels.

In the event of a design-basis accident as the containment pressure rises, the vacuum pumps will be automatically de-energized when the pressure increases to 0.20 psia above the setpoint. The vacuum pumps receive additional trip signals directly from a safety injection signal and indirectly from high containment pressure to ensure that the pumps are shut down. Therefore, the radioactive releases from the containment through the vacuum pump flow path will be negligible.

7.5.1.5 **Containment Isolation**

The containment isolation system is described in Section 5.2. The containment isolation system is designed to actuate and stroke the isolation valves completely closed to seal off the containment from the outside atmosphere when the pressure inside the containment reaches a predetermined setpoint.

The isolation trip valves are actuated by the safety injection system, the high containment pressure signal, or the high-high containment pressure signal, according to the functions of the line in which the trip valve is located (see Table 5.2-1). When the pressure setpoints are reached, each matrix operates electrical circuits to actuate electrically operated isolation valves directly, or to de-energize solenoid valves that release air from the diaphragm of pneumatically operated valves. Where two containment isolation trip valves are located on the same line, each trip valve is operated by a different redundant matrix. In lines containing only one trip valve, the trip valve is operated by both redundant matrices. However, lines containing one automatic trip valve have another isolation barrier, such as a check valve or a membrane barrier. All instruments, controls, and electrical equipment are supplied in accordance with ANSI, IEEE, and NEMA standards.

7.5.2 System Description

7.5.2.1 **Engineered Safeguards Actuation Instrumentation**

The engineered safeguards system actuation circuitry and hardware layout are designed to maintain channel isolation up to and including the bi-stable-operated logic relay similar to that of the reactor protection circuitry, as discussed in Section 7.2. The general arrangement of this layout is shown in Figure 7.5-3, with supplemental detailing in Figures 7.5-4 and 7.5-5. Although a four-channel system is illustrated in Figure 7.5-3, circuitry and hardware layout discussion is sufficiently general to apply to an n-channel system. Channel separation is maintained by providing separate racks for each analog protection channel, and separate relay rack compartments for each logic train. Channel identity is lost in the relay wiring required for matrix logic makeup. It should be noted that although channel individualization is lost, twin matrix logic trains are developed, thus ensuring a redundant actuation system.

The engineered safeguards system bi-stables drive the logic relay coils “C” and “D” as shown in Figures 7.5-3 and 7.5-5. These logic relay coils are de-energized by their bi-stables when an abnormal condition exists; the only exceptions to this “de-energized to operate” principle are the initiation of containment spray on CLS Hi Hi and the initiation of RWST recirculation mode transfer (RMT). Contacts of the relay are arranged so as to develop the logic matrix or combinations of signals required to initiate action. For example, in Figure 7.5-3 these relay contacts are shown directly below the relay coil. Since these coils would normally be energized, their contacts would remain open, and thus an open circuit between the voltage source and master actuating relay would exist. Dropping any of the two logic relay coils that would cause their corresponding contacts to close would complete the circuit and energize the master actuating relays. Although the illustration here is for a two-out-of-four (2/4) matrix make, the design and sequence of operation for (x_1/x_2) logic matrices makeup is the same. The master actuating relay (M) is a latch-type relay with two coils, an operate (M/0) and reset (M/R) coil, and electric reset. Once the logic matrix is made up, as described above, the circuit that energizes the master actuating relay is complete. Figure 7.5-3 illustrates the master actuating relay, and an enlarged view may be found in Figure 7.5-4. With a potential across the relay, the operate coil is energized, thus closing the M contacts, which energizes the slave relays (SRs and TD) as shown in Figure 7.5-3; the master relay is latched into this position until the reset coil is energized. Manual reset of the master actuating relay may be accomplished, after a time delay following its operation to ensure completion of the actuation sequence, by operating the reset switch (see Figures 7.5-3 and 7.5-4). With the reset coil energized, all of the M contacts are returned to their de-energized positions, as shown in Figure 7.5-3. It should be noted that once reset action is taken, the master relay operation is blocked by the reset relay R until the safeguards initiating signal clears, at which time it is automatically unblocked and restored to service. Resetting the master relay does not interfere with the operational status of the engineered safeguards equipment.

Annunciation is provided for the consequence-limiting-safeguards-initiated signal, the consequence-limiting-safeguards-reset-permissive signal, the safety-injection-initiated signal, and the safety-injection-blocked signal.

7.5.2.2 **Instrumentation Used During a Loss-of-Coolant Accident**

Instruments provided and designed to function following the major LOCA are those that govern the operation of engineered safeguards. Pressurizer pressure and level, and steam generator flow, and level sensors are located inside the containment because an equivalent signal cannot be obtained from a sensor location more isolated from the reactor. Steam generator pressure sensors are located outside the containment. It should be emphasized, however, that for the large LOCAs the initial suppression of the transient is independent of any detection or actuation signal because the water level will be restored to the core by the passive accumulator system.

Pumps used for safety injection and initial containment spray are located outside the containment. The operation of the equipment can be verified by instrumentation that reads in the control room. This instrumentation will not be affected by the accident. The containment sump level and refueling water storage tank instrumentation will provide information for evaluating the conditions necessary to initiate the recirculation mode of operation.

The containment level instrumentation has been changed to meet the requirements of TMI-2, NUREG-0578, Section 2.1.9. The system now utilizes redundant wide range level transmitters and redundant narrow range transmitters installed inside the reactor containment. The transmitters are qualified to IEEE-323-1974 and IEEE-344-1975 standards.

The wide-range level loops have the capability of measuring a level in the containment equivalent to approximately 580,000 gallon capacity and the narrow-range level loops have the capability of measuring to the top of the containment sump.

One of the redundant loops for wide-range level and one of the loops for narrow-range level is recorded on the postaccident monitoring recorder in the control room. The second redundant loop for both wide and narrow-range level can be real-time plotted through the PCS Emergency Response and Safety Parameter (ERG/SPDS) displays in the MCR, Technical Support Center and other locations.

Instrumentation has been added to monitor containment spray flow and backup pressurizer heater status during and following an accident. Containment spray flow instrumentation will provide a direct means for the Control Room operator to determine if containment spray flow is being provided. Likewise, pressurizer heater status will provide a direct means for the Control Room operator to determine satisfactory operation of the pressurizer heaters. Both containment spray flow and pressurizer heater status provide input to the plant NUREG-0696 MUX system for remote display in the Control Room and other locations.

Wide-range pressure transmitters have been added outside containment to measure containment pressure as described in Section 7.5.3.5.

Depending upon the magnitude of the loss-of-coolant incident, information relative to the pressure of the reactor coolant system will be useful to the operator to determine when it would be permissible to stop one of two LHSI pumps in the event of a small break. Regulatory Guide 1.97 reactor coolant system instrumentation as well as the discharge pressure of the charging pumps, as read on instrumentation outside the containment, will serve this purpose.

Consideration has been given to all the instrumentation and information that is necessary for recovery following a loss-of-coolant incident. Instrumentation external to the reactor containment, such as radioactivity monitoring equipment, will not be affected by this postulated incident, and will be available to the operator.

Safety-related postaccident monitoring panels for Units 1 and 2 have been installed in the control room, in response to NUREG-0578, Sections 2.1.5a, 2.1.6b, and 2.1.9. The panels are designed to IEEE 344-1975 and the original plant separation criteria. The components have been designed to meet, as a minimum, IEEE 323-1971. The panel contains switches and indicators for equipment such as containment isolation valves, RCS vent valves, and postaccident hydrogen indicators.

7.5.2.3 **Calibration and Testing**

The engineered safeguards actuation channels are designed with sufficient redundancy to provide the capability for channel calibration and test during power operation. Bypass removal of one actuation channel is accomplished by placing that channel in a tripped mode; i.e., a two-out-of-three matrix logic becomes a one-out-of-two matrix logic. Testing does not trip the system unless a trip condition occurs in a concurrent channel.

7.5.2.3.1 Analog Channel Testing

Engineered safeguards analog channel testing is identical to process analog protection channel testing as described in Section 7.2.2.1.4.

7.5.2.3.2 Logic Testing

Figures 7.5-3, 7.5-4, and 7.5-5 illustrate the basic logic test scheme. Test switches are located in the associated relay racks rather than in a single test panel. The following procedures indicate the method of testing the logic matrices:

1. Test of either train A or train B is made at one time; this is under administrative control.

2. A selection of the function to be tested is made. Figure 7.5-4, for example, illustrates some of these functional matrices.

3. The relay logic test switch is first turned to the test position, which opens the circuit to the master actuating relay (logic test switches as shown in Figure 7.5-4 or location 1 as shown in Figures 7.5-3 or 7.5-5) and energizes the “on test” labeled lamp (see position 3 of switch C_1 or D_1 in Figure 7.5-5).

   The master actuating relay is removed from this part of the test in order to avoid unintentional starting of the engineered safeguards equipment. Intentional start is available through the other train that has operational status and the other functional matrices not under test.

4. When the logic test switch is depressed in the test position, the circuit that normally energizes the logic relay coil is de-energized, thus closing the logic relay contacts operated by that coil (i.e., opening of C_1 at location 2 shown in Figure 7.5-3 or 7.5-5 will close the two logic relay contacts directly below C_1 in Figure 7.5-3). By repeating the above sequence for C_2, C_3, C_4, one can simulate all actuating logic combinations required to make up the logic required to develop the matrix. Thus, in Figure 7.5-3, a complete test of a two-out-of-four matrix is made with the following combinations: C_1 and C_2, C_1 and C_3, C_1 and C_4, C_2 and C_3, C_2 and C_4, and C_3 and C_4.

5. Proper development of a logic matrix would be indicated by the lighting of the matrix test lamps, as shown in Figure 7.5-4, and identified in Figure 7.5-5 as L_2.

6. With the testing of the logic matrix complete (i.e., steps 1 to 5), the matrix is returned to operational status by returning all test switches for that particular functional matrix to the “operate” position. The control board annunciator warns the operator of any test switch left in the test position, and thus the return to operational status through the action of the individual performing the test is verified by the operator at the control board. Testing procedures for the logic matrix of train B are identical to those described above for train A.

7. Verification of master actuating coil integrity is made by connecting an ohmmeter across the coil terminals.

8. Verification of slave coil integrity can be checked by connecting an ohmmeter across the coil terminals.

7.5.3 System Evaluation

Redundant instrumentation has been provided for all inputs to the protective systems and vital control circuits. Where wide process variable ranges and precise control are required, both wide-range and narrow-range instrumentation is provided. Instrumentation components are selected from standard commercially available products with proven operating reliability. The instrument power to electrical and electronic instrumentation required for safe and reliable operation is supplied from the four instrument buses.

The engineered safeguards systems are arranged so that there are multiple, separate, and independent pumping paths for delivering and circulating borated water to the reactor coolant system and to the spray system. This philosophy of multiplicity, separation, and independence has been extended to include the power sources as well as the signal sources, cabling, relays, etc., required for system actuation.

7.5.3.1 **Safety Injection**

Credible accident conditions requiring emergency core cooling would involve low pressurizer pressure and level. The present design for emergency core cooling is accomplished by the safety injection system actuation from primary system variables. Actuation is initiated by low-low-pressurizer pressure.

Pressurizer pressure is sensed by fast response pressure transmitters. An overall one-second channel response time is used, which is more than adequate to cover the response characteristics of the tripping channels.

Instrument delays are small in comparison with the computed lag in pressurizer pressure, which lags behind the reactor coolant pressure during blowdown. The successful operation of the engineered safeguards involves only actuation control function, with the single exception of the steam generator water level control function associated with unit cooldown using the auxiliary feedwater pump.

A safety injection block switch is provided to permit the primary system to be depressurized and its water level lowered for maintenance or refueling operations without actuation of the safety injection system. This manual block switch is interlocked with pressurizer pressure in such a way that the blocking action is automatically removed as operating pressure is approached. If two out of three pressure signals are above this preset pressure, blocking action cannot be initiated. The block condition is annunciated in the control room.

7.5.3.2 **Consequence Limiting Safeguards**

The design of the control system for the consequence limiting safeguards includes manual test switches for individual testing of all equipment in the system and for testing the system itself.

The containment vacuum control system, which starts and operates the mechanical vacuum pumps and the alarms, has adjustable setpoint mechanisms that allow the operator to change the setpoint value as required due to atmospheric conditions or experience gained in operating the plant.

7.5.3.3 **Containment Isolation System**

The system design offers a reliable and safe method for achieving the design-basis objectives.

Reliability in this system is ensured by the ability to calibrate and test each pressure-sensing device and monitor each manual reset relay during plant operation without removal from the system.

A fail-safe design is provided. On loss of air or control power, the pneumatically and solenoid-operated isolation valves close.

The three features that ensure the proper operation of this system are the location of pressure-sensing devices outside containment, continuous monitoring of valve positions, and indication of the availability of control power on the main control board.

The electrical circuits have manual reset relays, and each solenoid valve has a manual reset pushbutton designed to prevent accidental reopening of any isolation valve. The reset buttons on the control board must be set before the manual pushbutton on each solenoid valve can open any trip valve. As each pushbutton is reset, air is admitted through the solenoid valve to open the isolation valve. When all solenoid valves have been reset and isolation valves opened, tripping of the circuits can occur only if a trip signal initiates the action or the operator manually trips the relays in the control room.

See Section 5.2.2 for a discussion of the condenser air ejector discharge and vent system.

7.5.3.4 **Motor and Valve Control**

For starting pump and fan motors, the control relays are energized to energize the closing coil on the circuit-breaker of the motor-starter. When motor-starters are used, the starter operating coil is supplied by power from the same source as the subject motor. When circuit-breakers are used for motor control, the circuit-breakers close, and trip coils are supplied by power from a 125V dc battery bus, as outlined in Chapter 8.

For valve motor control, the control relay causes the coil on the main contactor for the closing circuit to be energized. The closing circuit is de-energized by the torque or limit switch on the valve operator, thereby ensuring that the valves have closed to a leak-tight position.

Air-actuated containment isolation valves are spring-loaded to close upon loss of air pressure.

An as-built tabulation of all valves and dampers actuated by engineered safeguards signals is provided in Table 7.5-2. The table includes component designation, service, safety function, signal source, and a statement of whether the safety function can be overridden or bypassed.

7.5.3.5 **Environmental Capability**

The engineered safeguards instrumentation equipment inside containment is designed to operate under the postaccident environment of a steam-air mixture and radiation.

Electrical equipment for the engineered safeguards is located inside the containment and in the auxiliary building. The equipment located inside the containment that must function in the postaccident environment is listed below. The expected length of time that the equipment will be required to function following an accident is also given.

1. Emergency core cooling system containment isolation actuation sensors (first five minutes after accident).
2. Emergency core cooling system motor-operated valves and flow instrumentation (first five minutes after accident).
3. Accumulator level instrumentation (first five minutes after accident).
4. Containment sump level instrumentation three hours after accident, which is considered to be the maximum period after a LOCA for emptying the refueling water storage tank into the sump, thereby ensuring that the sump is sufficiently filled for the recirculation phase.
5. Air-operated and motor-operated containment isolation valves (operation completed in first five minutes after accident).
6. Containment pressure instrumentation (continuous service).
7. Power and instrumentation cables for the above-listed equipment.

The design considerations and specifications to be used in the selection of motors that must function in the postaccident environment are discussed in Chapter 6. Similar application criteria apply to the specifications of control and instrumentation equipment and other electrical equipment.

Failure of the above equipment after the specific time will not increase the severity or consequences of the accident. The reactor protection control and instrumentation equipment and electrical equipment for engineered safeguards located in the Auxiliary Building will operate in a normal ambient environment following a LOCA. Auxiliary Building equipment in the containment sump-water recirculation loop is listed below:

1. Safety injection/charging lines and charging pumps.
2. Flow, temperature, and pressure instrumentation for the safety injection/charging system.
3. Power and instrument cables for the above.

Areas of high radiation would exist inside the containment and in those portions of the auxiliary building near safety injection/charging system equipment following a major LOCA. The maximum intregrated six-month LOCA dose in the containment would be approximately 3.7×10^7 rads. The maximum intregrated six-month LOCA dose plus sixty year normal operation dose in the charging cubical (lower elevation) of the Auxiliary Building would be approximately 1.2×10^7 rads. The ability of electrical equipment in the emergency core cooling system to withstand radiation exposure would be limited by radiation effects on electrical insulation materials and motor bearing lubrication.

The electrical equipment for the emergency core cooling system located in the containment use only radiation-resistant insulating materials. These insulating materials have a threshold for radiation damage that might affect their function of 10^8 rad or higher. They therefore provide considerable margin above the maximum postaccident radiation dose that would result from the exposure times specified above.

The lower ambient temperatures and radiation levels in the auxiliary building permit the use of normal elastomer or plastic insulation materials. These materials have a threshold for radiation damage of 10^6 rad or higher. Where required, because of location in possible high-radiation areas, motor bearings are lubricated with radiation-rated lubricants.

The pressure sensors that monitor containment conditions subsequent to a LOCA are capable of indicating pressures from 0 psia to 65 psia. The temperature sensors that monitor containment conditions subsequent to a LOCA are capable of indicating temperatures from 40°F to 400°F. The pressure and temperature sensors that monitor containment conditions subsequent to a LOCA are capable of indicating conditions more severe than those associated with the design basis of the containment. The pressure and temperature conditions for the design basis of the containment are 45 psig and 280°F.

The requirements of TMI-2 Short Term Lessons Learned, NUREG-0578 and subsequent clarifications contained in the NRC letter dated October 30, 1979, required that there be a continuous indication of containment pressure provided in the control room with an indication capability to three times the containment design pressure. As a result, redundant Class 1E pressure transmitters were added to the existing containment pressure measuring tubing with the capability of measuring a pressure range of 0 to 180 psia. The pressure transmitters are qualified to IEEE 323-1971 and IEEE 344-1975.

Each transmitter has an indicator associated with it. These indicators are mounted on the main control board and provide continuous indication of the containment pressure over the range of 0 to 180 psia. One of the redundant loops for the containment pressure measurement is recorded in the control room on the postaccident monitoring recorder. The second redundant loop can be real-time plotted through the PCS ERG/SPDS displays in the MCR, Technical Support Center, and other locations.

7.5.3.5.1 Environmental Qualification of Safety-Related Electrical Equipment

In response to IE Bulletin 79-01B, a program was established to review the environmental qualification of safety-related electrical equipment located inside the containment. Later, a supplement to IE Bulletin 79-01B was issued and further defined the scope of the review to include not only equipment inside the containment, but also equipment in areas of the plant where changing environmental conditions (temperature, pressure, humidity, radiation) occur during and as a result of the accident conditions being reviewed.

The IE Bulletin 79-01B review was submitted in two separate parts. The 45-day review (Reference 1), reflected equipment qualifications to FSAR commitments. The review included a list of safety-related systems that are required to achieve or support (1) emergency reactor shutdown, (2) containment isolation, (3) reactor core cooling, (4) containment heat removal, (5) core residual heat removal, and (6) prevention of significant release of radioactive material to the environment. This list is included on Table 7.5-3. Equipment identified as requiring a review were analyzed for conditions of temperature, pressure and humidity inside and outside the containment, and for submergence, aging, chemical spray, and radiation.

Revision 4 to the 90-day review (Reference 2), was also submitted. It included a list of electrical equipment required to mitigate an accident and/or safely shut down the plant and that are subjected to a changing environment due to the accidents. The report reflects the updated Status of Qualification of the electrical equipment. Results of the NRC's safety evaluation for the environmental qualification of safety-related equipment at the Surry Power Station are contained in Reference 3.

7.5 REFERENCES

1. Letter from Vepco to NRC, Subject: *45-Day Response to IE Bulletin 79-01B,* dated June 16, 1980 (Serial No. 527).
2. Letter from Vepco to NRC, Subject: *Response to Safety Evaluation Report for Environmental Qualification of Safety Related Electrical Equipment IE Bulletin 97-01B 90-Day Review (Revision 4 of 90-Day Response to IE Bulletin 79-01B),* dated August 24, 1981 (Serial No. 329).
3. Letter from S. A. Varga, NRC, to W. L. Stewart, Vepco, Subject: *Transmittal of the Safety Evaluation Report for Environmental Qualification of Safety-Related Equipment at Surry Power station, Unit Nos. 1 and 2,* dated January 26, 1983.

Table 7.5-1
ENGINEERED SAFEGUARDS ACTUATION FUNCTIONS

Actuation Signal	Coincidence Circuitry and Interlocks	Comments
I. Containment Isolation Actuation Function		
1. Hi CLS	Coincidence of 3/4 containment high pressure or 1/2 manual	Closes containment isolation valves for the following lines: instrumentation air suction supply line, radiation monitoring gas and particulate sample supply line, air ejector vent to containment line.
2. HiHi CLS	Coincidence of 3/4 containment high-high pressure or 2/2 manual	Closes containment isolation valves for the following systems: CC, IA, MS.
3. Safety injection actuation	Coincidence of 2/3 Low Low pressurizer pressure or 1/2 manual	Closes containment isolation valves for the following systems: CH, RC, BD, CC, CV, DA, DG, LM, SS, VG, SI (N2 supply), MS (drains).
II. Main Steam Lines Isolation Actuation Function		
1. Main steam line isolation	High steam line flow in 2 out of 3 lines (1/2 per line) coincident with either low T_{avg} in 2 out of 3 loops or low steam pressure in 2 out of 3 lines	Closes main steam line isolation valves.
2. Hi Hi CLS	3/4 high-high containment pressure signal or 2/2 manual	Closes main steam line isolation valves.
3. Manual per steam loop	1/1 per steam line	Closes main steam line isolation valves.
III. Auxiliary Feedwater Actuation Function		
1. Turbine driven pump start	Coincidence of 2/3 low-low level in any two steam-generators, or loss of power to station service busses; or manual 1/1, or AMSAC initiated	Starts turbine driven pump.
2. Motor-driven pumps start	2/3 low-low level in any steam-generator, or trip of both main feedwater pumps, or safety injection signal, or manual 1/1, or total loss of reserve station service power, or AMSAC initiated	Start motor driven pump.

Table 7.5-1 (CONTINUED)
ENGINEERED SAFEGUARDS ACTUATION FUNCTIONS

Actuation Signal	Coincidence Circuitry and Interlocks	Comments
IV. Main Feedwater Isolation Function		
1. Safety injection actuation	SI actuation	Close main feedwater control valves (fast closure).
2. Hi Hi steam generator level	2/3 high high level in steam generator	Close main feedwater control valves (fast closure).

Table 7.5-2
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-BD-TV-100A	Steam generator 1A blowdown inside cont isolation valve	Closed	SGLLWL	None
1-BD-TV-100B	Steam generator 1A blowdown outside cont isolation valve	Closed	SGLLWL	None
1-BD-TV-100C	Steam generator 1B blowdown inside cont isolation valve	Closed	SGLLWL	None
1-BD-TV-100D	Steam generator 1B blowdown outside cont isolation valve	Closed	SGLLWL	None
1-BD-TV-100E	Steam generator 1C blowdown inside cont isolation valve	Closed	SGLLWL	None
1-BD-TV-100F	Steam generator 1C blowdown outside cont isolation valve	Closed	SGLLWL	None
1-CC-TV-105A	RCP A CC water cooler outside cont isolation valve	Closed	CLS-HiHi	None
1-CC-TV-105B	RCP B CC water cooler outside cont isolation valve	Closed	CLS-HiHi	None
1-CC-TV-105C	RCP C CC water cooler outside cont isolation valve	Closed	CLS-HiHi	None
1-CC-TV-109A	CC water from RHR HX outside cont isolation valve	Closed	SI	None
1-CC-TV-109B	CC water from RHR HX outside cont isolation valve	Closed	SI	None
1-CC-TV-110A	Reactor cont recirc cooler A CC water outside cont isolation valve	Closed	CLS-HiHi	None
1-CC-TV-110B	Reactor cont recirc cooler B CC water outside cont isolation valve	Closed	CLS-HiHi	None
1-CC-TV-110C	Reactor cont recirc cooler C CC water outside cont isolation valve	Closed	CLS-HiHi	None
1-CC-TV-140A	RCP thermal barrier CC water inside isolation valve	Closed	CLS-HiHi	None

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-CC-TV-140B	RCP thermal barrier CC water outside isolation valve	Closed	CLS-HiHi	None
1-CH-HCV-1200A [a]	Letdown orifice isolation valve	Closed	SI	None
1-CH-HCV-1200B [a]	Letdown orifice isolation valve	Closed	SI	None
1-CH-HCV-1200C [a]	Letdown orifice isolation valve	Closed	SI	None
1-CH-MOV-1115B [a]	RWST to charging pump suction isolation valve	Open	SI	None
1-CH-MOV-1115C [a]	VCT to charging pump suction isolation valve	Closed	SI	None
1-CH-MOV-1115D [a]	RWST to charging pump suction isolation valve	Open	SI	None
1-CH-MOV-1115E [a]	VCT to charging pump suction isolation valve	Closed	SI	None
1-CH-MOV-1289A [a]	Charging line to regenerative HX isolation valve	Closed	SI	None
1-CH-MOV-1289B [a]	Charging line to regenerative HX isolation valve	Closed	SI	None
1-CH-MOV-1381 [a]	RCP seal water return isolation valve	Closed	SI	None
1-CH-TV-1204A	Letdown line inside cont isolation valve	Closed	SI	None
1-CH-TV-1204B	Letdown line outside cont isolation valve	Closed	SI	None
1-CS-MOV-100A [a]	Cont spray pump A from RWST isolation valve	Open	CLS-HiHi	None
1-CS-MOV-100B [a]	Cont spray pump B from RWST isolation valve	Open	CLS-HiHi	None

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-CS-MOV-101A [a]	Cont spray pump A discharge isolation valve	Open	CLS-HiHi	None
1-CS-MOV-101B [a]	Cont spray pump A discharge isolation valve	Open	CLS-HiHi	None
1-CS-MOV-101C [a]	Cont spray pump B discharge isolation valve	Open	CLS-HiHi	None
1-CS-MOV-101D [a]	Cont spray pump B discharge isolation valve	Open	CLS-HiHi	None
1-CV-TV-150A	Cont vacuum pump B outside cont isolation valve	Closed	SI	None
1-CV-TV-150B	Cont vacuum pump B outside cont isolation valve	Closed	SI	None
1-CV-TV-150C	Cont vacuum pump A outside cont isolation valve	Closed	SI	None
1-CV-TV-150D	Cont vacuum pump A outside cont isolation valve	Closed	SI	None
1-CW-MOV-100A [a]	Circ water condenser outlet isolation valve	Closed	CLS-HiHi *	None
1-CW-MOV-100B [a]	Circ water condenser outlet isolation valve	Closed	CLS-HiHi *	None
1-CW-MOV-100C [a]	Circ water condenser outlet isolation valve	Closed	CLS-HiHi *	None
1-CW-MOV-100D [a]	Circ water condenser outlet isolation valve	Closed	CLS-HiHi *	None
1-CW-MOV-106A [a]	Circ water condenser inlet isolation valve	Closed	CLS-HiHi *	None
1-CW-MOV-106B [a]	Circ water condenser inlet isolation valve	Closed	CLS-HiHi *	None
1-CW-MOV-106C [a]	Circ water condenser inlet isolation valve	Closed	CLS-HiHi *	None

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-CW-MOV-106D [a]	Circ water condenser inlet isolation valve	Closed	CLS-HiHi *	None
1-DA-TV-100A	Reactor cont sump pump inside containment isolation valve	Closed	SI	None
1-DA-TV-100B	Reactor cont sump pump outside containment isolation valve	Closed	SI	None
1-DA-TV-103A	Post accident SS return to cont sump outside cont isolation valve	Closed	SI	None
1-DA-TV-103B	Post accident SS return to cont sump outside cont isolation valve	Closed	SI	None
1-DG-TV-108A	Primary drain transfer pump inside containment isolation valve	Closed	SI	None
1-DG-TV-108B	Primary drain transfer pump outside containment isolation valve	Closed	SI	None
1-IA-TV-100	Cont instr air discharge outside cont isolation valve	Closed	CLS-HiHi	None
1-IA-TV-101A	Cont instr air supply inside cont isolation valve	Closed	CLS-Hi	None
1-IA-TV-101B	Cont instr air inside cont isolation valve	Closed	CLS-Hi	None
1-LM-TV-100A	Leakage monitoring tap outside cont isolation valve	Closed	SI	None
1-LM-TV-100B	Leakage monitoring tap outside cont isolation valve	Closed	SI	None
1-LM-TV-100C	Leakage monitoring tap outside cont isolation valve	Closed	SI	None
1-LM-TV-100D	Leakage monitoring tap outside cont isolation valve	Closed	SI	None
1-LM-TV-100E	Leakage monitoring tap 4, 7, 9, 10 outside cont isolation valve	Closed	SI	None

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-LM-TV-100F	Leakage monitoring tap 4, 7, 9, 10 outside cont isolation valve	Closed	SI	None
1-LM-TV-100G	Leakage monitoring tap 2, 5 outside cont isolation valve	Closed	SI	None
1-LM-TV-100H	Leakage monitoring tap 2, 5 outside cont isolation valve	Closed	SI	None
1-MS-TV-101A	Main steam line A isolation valve	Closed	CLS-HiHi	None
1-MS-TV-101B	Main steam line B isolation valve	Closed	CLS-HiHi	None
1-MS-TV-101C	Main steam line C isolation valve	Closed	CLS-HiHi	None
1-MS-TV-109	Main steam drain condensate drain isolation valve	Closed	SI	None
1-MS-TV-110	Main steam drain condensate drain isolation valve	Closed	SI	None
1-RC-TV-1519A	PG water to pzr relief tank - outside cont isolation valve	Closed	SI	None
1-RM-TV-100A	RM gas part supply outside cont isolation valve	Closed	CLS-Hi	None
1-RM-TV-100B	RM gas part supply outside cont isolation valve	Closed	CLS-Hi	None
1-RM-TV-100C	RM gas part supply inside cont isolation valve	Closed	CLS-Hi	None
1-RS-MOV-155A [a]	Outside recirc spray pump A suction isolation valve	Open	CLS-HiHi	None
1-RS-MOV-155B [a]	Outside recirc spray pump B suction isolation valve	Open	CLS-HiHi	None
1-RS-MOV-156A [a]	Outside recirc spray pump A discharge isolation valve	Open	CLS-HiHi	None

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-RS-MOV-156B [a]	Outside recirc spray pump B discharge isolation valve	Open	CLS-HiHi	None
1-SI-MOV-1865A	Accumulator loop A discharge isolation valve	Open	SI	Key Switch [b]
1-SI-MOV-1865B	Accumulator loop B discharge isolation valve	Open	SI	Key Switch [b]
1-SI-MOV-1865C	Accumulator loop C discharge isolation valve	Open	SI	Key Switch [b]
1-SI-MOV-1867C [a]	High head SI to cold leg isolation valve	Open	SI	None
1-SI-MOV-1867D [a]	High head SI to cold leg isolation valve	Open	SI	None
1-SI-TV-100	Central nitrogen supply outside cont isolation valve	Closed	SI	None
1-SI-TV-101A	Accumulator nitrogen relief outside cont isolation valve	Closed	SI	None
1-SI-TV-101B	Accumulator nitrogen relief outside cont isolation valve	Closed	SI	None
1-SI-TV-102A	RWST cross tie to charging pump suction isolation valve	Open	SI	None
1-SI-TV-102B	RWST cross tie to charging pump suction isolation valve	Open	SI	None
1-SS-TV-100A	SS pzr liquid space inside cont isolation valve	Closed	SI	None
1-SS-TV-100B	SS pzr liquid space outside cont isolation valve	Closed	SI	None
1-SS-TV-101A	SS pzr vapor space inside cont isolation valve	Closed	SI	None
1-SS-TV-101B	SS pzr vapor space outside cont isolation valve	Closed	SI	None

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-SS-TV-102A	SS primary coolant cold leg sample inside cont isolation valve	Closed	SI	None
1-SS-TV-102B	SS primary coolant cold leg sample outside cont isolation valve	Closed	SI	None
1-SS-TV-103A	SS RHR sample inside cont isolation valve	Closed	SI	None
1-SS-TV-103B	SS RHR sample outside cont isolation valve	Closed	SI	None
1-SS-TV-104A	SS pzr relief tank gas space sample inside cont isolation valve	Closed	SI	None
1-SS-TV-104B	SS pzr relief tank gas space sample outside cont isolation valve	Closed	SI	None
1-SS-TV-106A	SS primary coolant hot leg inside cont isolation valve	Closed	SI	None
1-SS-TV-106B	SS primary coolant hot leg outside cont isolation valve	Closed	SI	None
1-SV-TV-102	Air ejector vent to cont isolation valve	Closed	CLS-Hi	None
1-SV-TV-102A	Air ejector vent to cont outside isolation valve	Closed	SI	None
1-SW-MOV-101A [a]	SW to bearing cooling water Hx isolation valve	Closed	CLS-HiHi *	None
1-SW-MOV-101B [a]	SW to bearing cooling water Hx isolation valve	Closed	CLS-HiHi *	None
1-SW-MOV-102A [a]	SW to CC water HX isolation valve	Closed	CLS-HiHi *	None
1-SW-MOV-102B [a]	SW to CC water HX isolation valve	Closed	CLS-HiHi *	None
1-SW-MOV-103A [a]	SW to recirc spray HX (A, D) isolation valve	Open	CLS-HiHi	None

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-SW-MOV-103B [a]	SW to recirc spray HX (A, D) isolation valve	Open	CLS-HiHi	None
1-SW-MOV-103C [a]	SW to recirc spray HX (B, C) isolation valve	Open	CLS-HiHi	None
1-SW-MOV-103D [a]	SW to recirc spray HX (B, C) isolation valve	Open	CLS-HiHi	None
1-SW-MOV-104A [a]	SW to recirc spray HX A inlet isolation valve	Open	CLS-HiHi	None
1-SW-MOV-104B [a]	SW to recirc spray HX B inlet isolation valve	Open	CLS-HiHi	None
1-SW-MOV-104C [a]	SW to recirc spray HX C inlet isolation valve	Open	CLS-HiHi	None
1-SW-MOV-104D [a]	SW to recirc spray HX D inlet isolation valve	Open	CLS-HiHi	None
1-SW-MOV-105A [a]	SW to recirc spray HX A outlet isolation valve	Open	CLS-HiHi	None
1-SW-MOV-105B [a]	SW to recirc spray HX B outlet isolation valve	Open	CLS-HiHi	None
1-SW-MOV-105C [a]	SW to recirc spray HX C outlet isolation valve	Open	CLS-HiHi	None
1-SW-MOV-105D [a]	SW to recirc spray HX D outlet isolation valve	Open	CLS-HiHi	None
1-VG-TV-109A	Primary drains tank vent inside cont isolation valve	Closed	SI	None
1-VG-TV-109B	Primary drains tank vent outside cont isolation valve	Closed	SI	None
1-VS-AOD-101A	Fuel bldg supply fan damper to HEPA emergency filter	Closed	SI	Mode Switch [c]
1-VS-AOD-101B	Fuel bldg supply fan damper to HEPA emergency filter	Closed	SI	Mode Switch [c]

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-VS-AOD-102	Fuel bldg exhaust fans to vent stack	Closed	SI	None
1-VS-AOD-103A	Decon bldg fan discharge damper to emergency filter	Closed	SI	None
1-VS-AOD-103B	Decon bldg fan discharge damper to emergency filter	Closed	SI	None
1-VS-AOD-104	Decon bldg damper to decon bldg exhaust fans	Closed	SI	None
1-VS-AOD-105A	Unit 1 cont air compressor damper to HEPA emergency filter	Closed	SI	None
1-VS-AOD-105B	Unit 1 cont air compressor damper to HEPA emergency filter	Closed	SI	None
1-VS-AOD-107A	Aux bldg central exhaust fan damper to HEPA emergency filter	Open	SI	Mode Switch [c]
1-VS-AOD-107B	Aux bldg central exhaust fan damper to HEPA emergency filter	Open	SI	Mode Switch [c]
1-VS-AOD-108	Aux bldg central exhaust fan damper to vent stack	Closed	SI	Mode Switch [c]
1-VS-AOD-109A	Aux bldg general area exhaust fans damper	Closed	SI	None
1-VS-AOD-109B	Aux bldg general area exhaust fans damper	Closed	SI	None
1-VS-AOD-110	Aux bldg general area exhaust fans to vent stack	Closed	SI	None
1-VS-AOD-111A	Cont purge exhaust damper to HEPA emergency filter	Closed	SI	None
1-VS-AOD-111B	Cont purge exhaust damper to HEPA emergency filter	Closed	SI	None
1-VS-MOD-100A	Unit 1 safeguards to HEPA emergency filters damper	Open	SI	Mode Switch [c]

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.

b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.

c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-2 (CONTINUED)
VALVES/DAMPERS ACTUATED BY ENGINEERED SAFEGUARDS SIGNALS

Designation (Valve or Damper Tag No.) (Similar for Unit 2)	Service (Actuated Valve or Damper Description)	Function (Actuated Valve or Damper Position)	Signal (Actuation Signal)	Override/Bypass (Override or bypass condition following actuation)
1-VS-MOD-100B	Unit 1 safeguards to HEPA emergency filters damper	Open	SI	Mode Switch [c]
1-VS-MOD-103A	Control room supply air isolation damper	Closed	SI	None
1-VS-MOD-103B	Control room exhaust air isolation damper	Closed	SI	None
1-VS-MOD-103C	Control room supply air isolation damper	Closed	SI	None
1-VS-MOD-103D	Control room exhaust air isolation damper	Closed	SI	None

Legend
SI = Safety Injection
SGLLWL = Steam Generator Low-Low Water Level
CLS-Hi = Consequence Limiting Safeguards - High
CLS-HiHi = Consequence Limiting Safeguards - High High or CLS-HiHi* when coincident with undervoltage

a. These circuits have features that could prevent immediate operation of the component when the engineered safeguards signal is actuated. Such features are a necessary part of the circuit (such as a limit switch), or they require conscious effort by an operator to prevent operation (such as manipulation of a pushbutton or a selector switch). A valve limit switch could act to delay safeguards-initiated operation if the valve was in mid-travel and had to complete the travel sequence before operating in response to the safeguards signal. A pushbutton or selector switch held in the actuated position gives the operators an option, in some cases, of delaying component response to an emergency safeguards signals.
b. A key-operated switch is under administrative control to prevent inadvertent component operation and to satisfy the requirements of IEEE Standard 279-1971.
c. A mode switch is under administrative control to prevent inadvertent alignment of this damper during refueling (Section 9.13.4.1).

Table 7.5-3
SAFETY-RELATED SYSTEMS

Function	System
Emergency reactor shutdown	Reactor coolant Reactor protection Safeguards actuation Chemical and volume control
Containment isolation	Containment isolation
Reactor core cooling	High pressure injection Low pressure injection Accumulators
Containment heat removal	Containment spray Containment ventilation Containment sump recirculation
Core residual heat	Residual heat removal Pressurizer spray Power-operated relief valves Main feedwater Auxiliary feedwater Main steam Steam dump Component cooling water Service water
Prevention of significant release of radioactive material to environment	Containment spray (iodine removal) Containment air purification Containment gas control Containment radiation monitoring Containment radiation sampling
Supporting systems	Emergency power Control room and safety equipment area ventilation

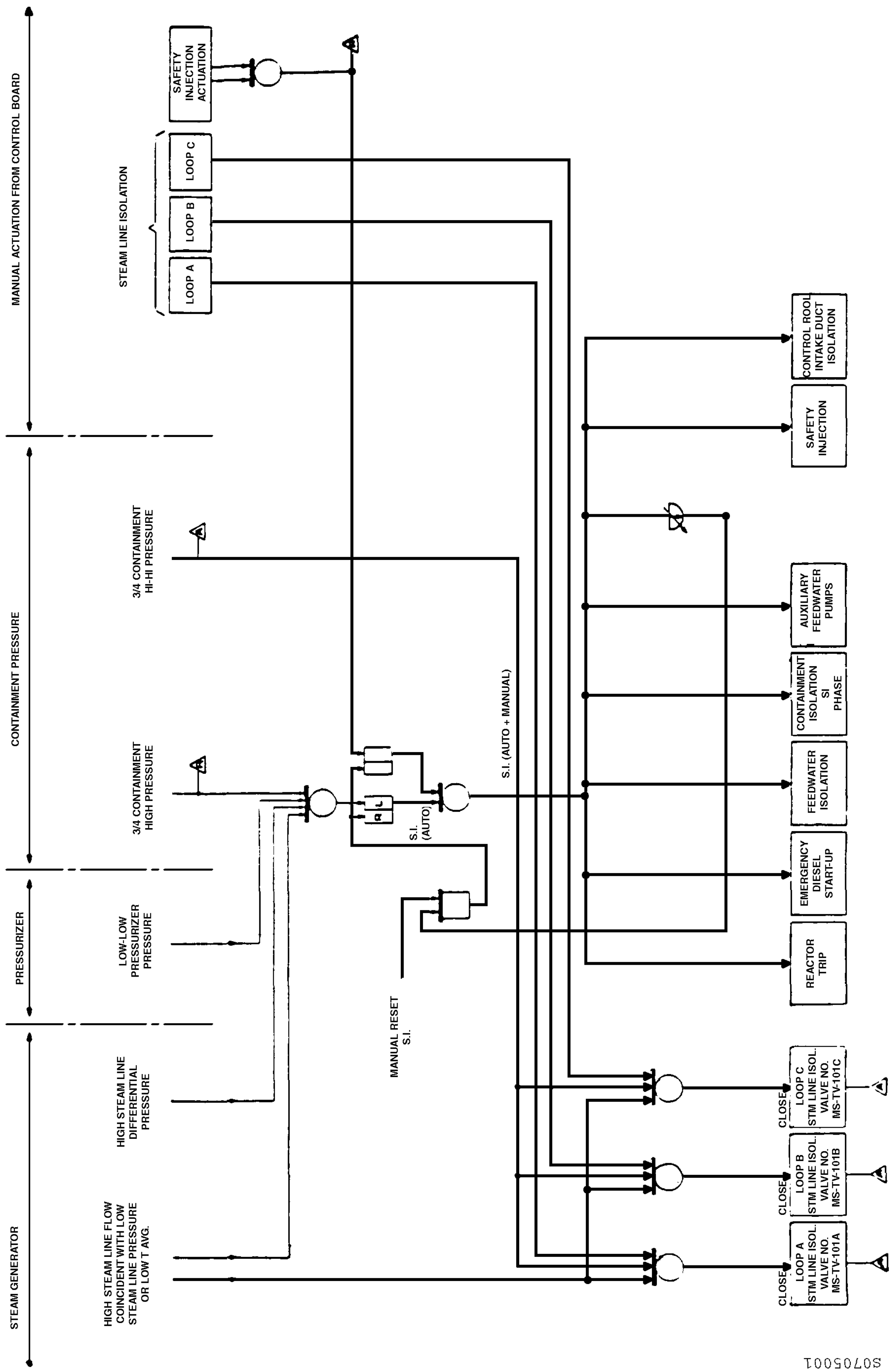


Figure 7.5-1
SAFETY INJECTION SYSTEM ACTUATION

Figure 7.5-2
CONSEQUENCE-LIMITING SAFEGUARDS INITIATION SYSTEM

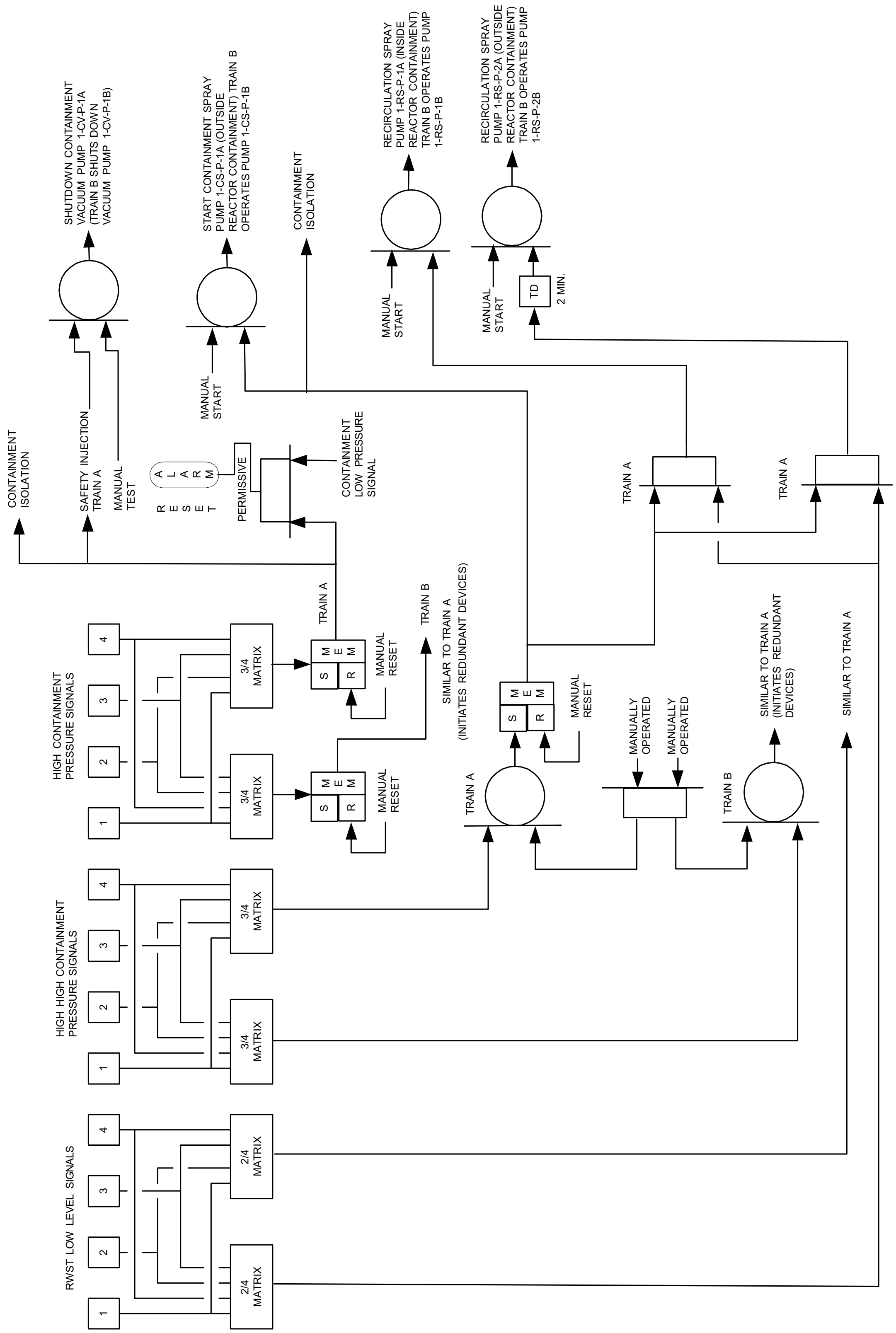


Figure 7.5-3
ENGINEERED SAFEGUARDS ACTUATION CIRCUITS

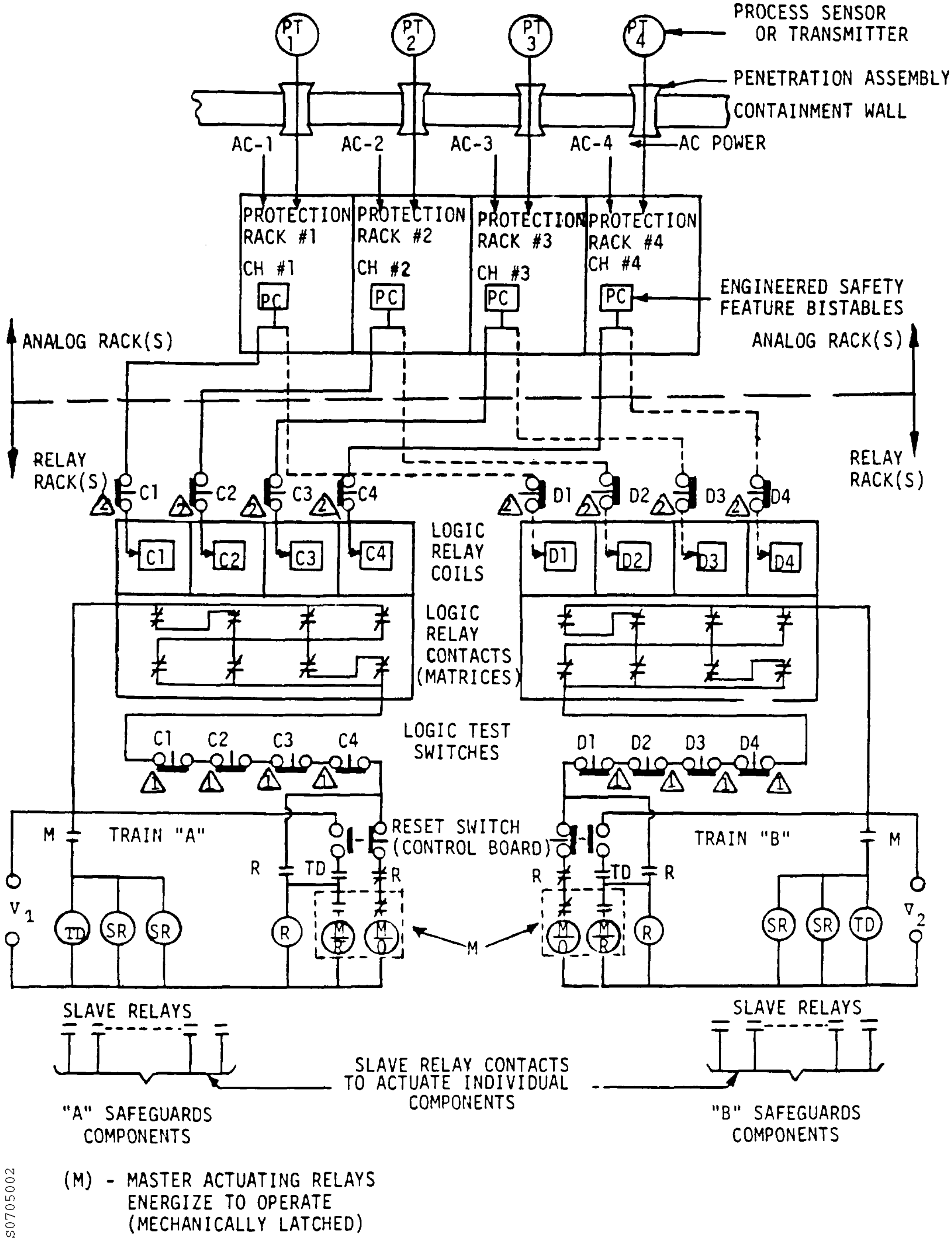


Figure 7.5-4
SIMPLIFIED DIAGRAM FOR OVERALL LOGIC RELAY TEST SCHEME

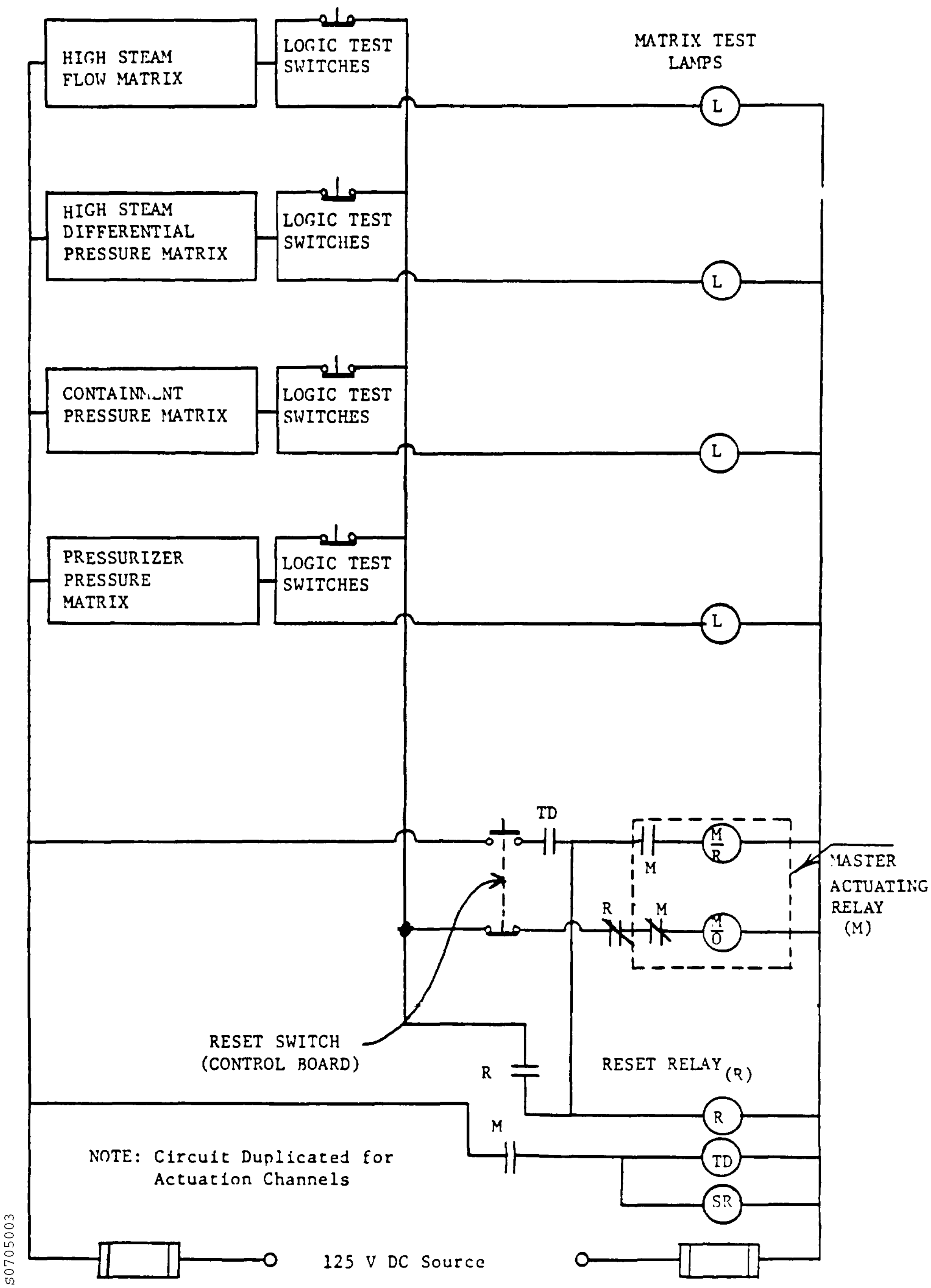
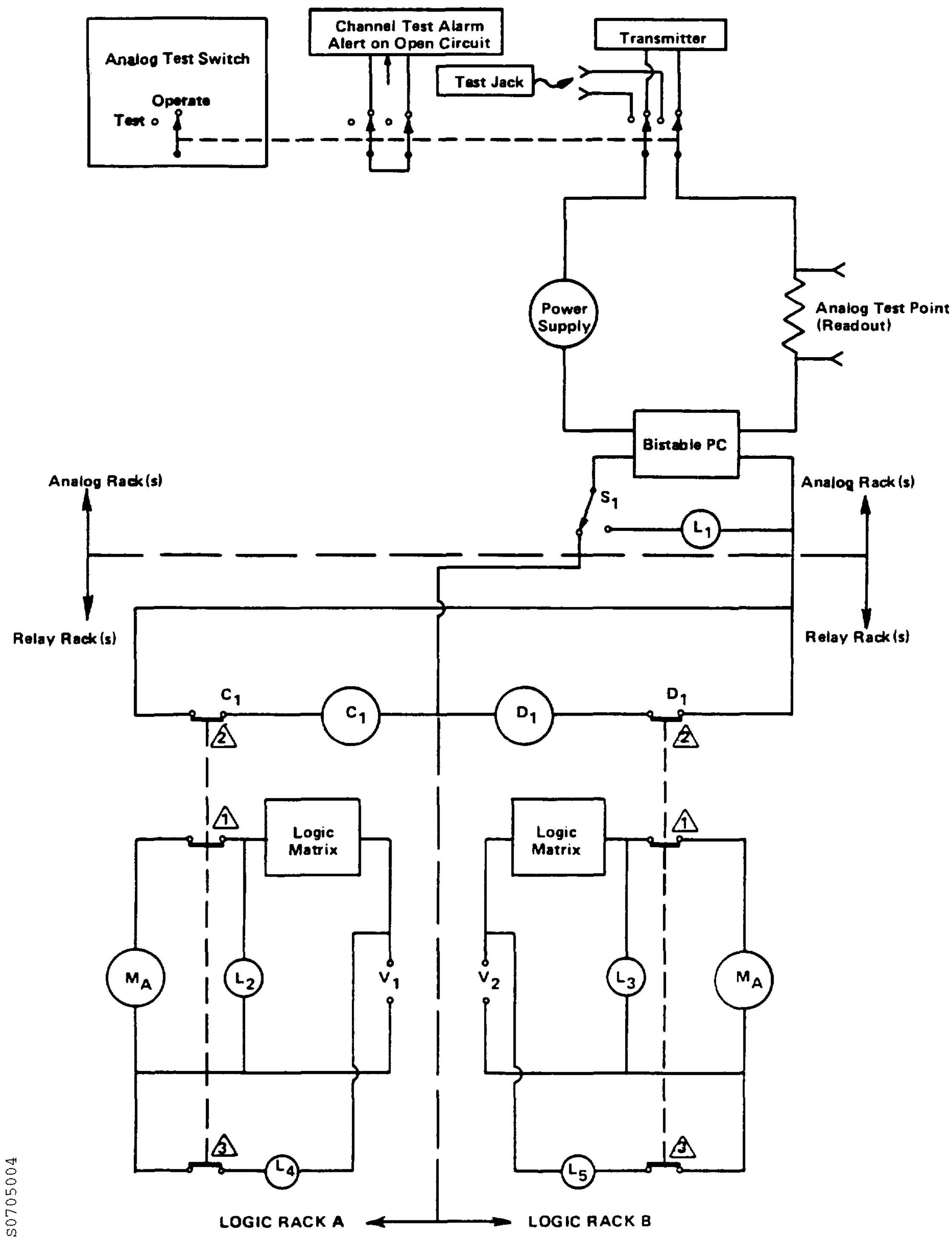


Figure 7.5-5
SIMPLIFIED DIAGRAM RELAY LOGIC CHANNEL TESTING



7.6 INCORE INSTRUMENTATION

7.6.1 Design Basis

The incore instrumentation is designed to yield information on the neutron flux distribution at selected core locations. Using the information thus obtained, it is possible to confirm the reactor core design parameters. The system provides means for acquiring data only, and performs no operational unit control.

7.6.2 System Description

7.6.2.1 General

The incore instrumentation system consists of retractable flux thimbles, which run the length of selected fuel assemblies, and moveable fission detectors which are inserted into the retractable flux thimbles. The detectors are used to collect flux distribution data. The retractable flux thimbles are shown in Figures 7.6-1 and 7.6-2.

Fifty core locations on each unit are capable of housing retractable flux thimbles. Each flux thimble houses 3 core exit thermocouples (1 in service with 2 installed spares) used to measure core exit temperature in post accident conditions as required by Reg Guide 1.97. The core exit thermocouples are not a functional part of the incore system, however, the incore system provides a means of placing the core exit thermocouple in the core. The core exit thermocouples provide input to the Inadequate Core Cooling System and are discussed in more detail in Section 7.9.

The thimbles are retractable and are inserted into the reactor at the seal table. Caps may be installed in the event a thimble location must be removed from service. Technical Specifications provide the requirements for the number and location of operable flux thimble locations.

The data collected by the incore system in conjunction with previously calculated analytical information is used to determine the fission power distribution. This method is more accurate than using calculational methods alone. The data collected by the incore system may also be used to calculate coolant enthalpy distribution ($F_{\Delta h}$), total peaking factor (F_Q), and the fuel burnup distribution. Once analyzed, the measured data is compared to power distribution and thermal/hydraulic limits which is the primary way to determine the maximum allowable power output. The radial and axial power distribution may also be evaluated by comparing the power distribution between quadrants.

7.6.2.2 Thermocouples

Three chromel-alumel, grounded, twinax, thermocouples are permanently installed at the tip of each of the 50 flux thimbles. The thermocouples and extension leads are installed in the annulus of the non-concentric flux thimble inner calibration tube and the outer sheath as shown in Figures 7.6-1 and 7.6-2. The thermocouple extension leads are mineral insulated with stainless steel sheaths. For each guide tube, one thermocouple circuit is active and monitored by the Emergency Response Facilities Data Acquisition System, which provides parallel data to the

Inadequate Core Cooling Monitor System and the PCS. The other two thermocouples associated with each flux thimble are installed spares.

7.6.2.3 **Movable Neutron Detectors**

7.6.2.3.1 Mechanical Configuration

The neutron flux detectors, remotely positioned in the core, provide remote readout for flux mapping. The basic system for the insertion of these detectors is as shown in Figure 7.6-3. Retractable flux thimbles, which contain thermocouples and the calibration tube, are pushed into the reactor core through thimble guide tubes (conduits). These thimble guide tubes extend from the bottom of the reactor vessel down through the concrete shield area, then up to a thimble seal table.

The retractable thimbles are closed at the leading (reactor) ends, are dry inside, and the calibration tube serves as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the thimble guide tubes are provided at the seal table, as shown on Figures 7.6-1 and 7.6-2.

Surry Power Station is in the process of replacing the Westinghouse designed flux thimbles and seal table seals shown on Figure 7.6-1 with the design that is shown on Figure 7.6-2. The replacement project is planned for implementation over several refueling outages. The configuration of the flux thimbles does not change and will consist of an inner calibration tube that is used to insert and withdraw the in-core neutron detectors, three type K, grounded thermocouples and an outer tube. The inner tube is also part of the Reactor Coolant System pressure boundary. The principal difference between the Westinghouse and replacement designs is in the high and low pressure seals and the seal housing at the top of the flux thimble guide tube. Detailed descriptions of each design are included in Surry Power Station vendor technical manuals and applicable vendor drawings.

During reactor operations, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal table is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists of a combination of drive assemblies, five-path rotary transfer devices, and ten-path rotary transfer devices, as shown in Figure 7.6-3. The drive system pushes hollow helical-wrap drive cables into the core. Miniature detectors are attached to the leading ends of the cables, and small-diameter sheathed coaxial cables are threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor that pushes a helical-wrap drive cable and detector through a selective thimble path by means of a special drive box, and includes a storage device that accommodates the total drive cable length. Further information on mechanical design and support is provided in Chapter 3.

7.6.2.3.2 Control and Readout Description

The control and readout system provides means to rapidly traverse the miniature neutron detectors to and from the reactor core at 72 ft/min, and to traverse the reactor core at 12 ft/min while plotting the thermal neutron flux versus detector position. The control system consists of two sections, one physically mounted with the drive units, and the other contained in the control room. Limit switches in each tubing run provide signals to the path display to indicate the active detector path during the flux mapping operation. Each gear box drives an encoder for position indication. One five-path group path selector is provided for each drive unit to route the detector into one of the flux thimble groups or to storage. A ten-path rotary transfer assembly is used to route a detector into any one of up to ten selectable thimbles. Manually operated isolation valves on each thimble allow free passage of the detector and drive cable when open. When closed, these valves prevent steam leakage from the core in case of a thimble rupture. Provision is made to separately route each detector into a common flux thimble to permit cross calibration of the detectors.

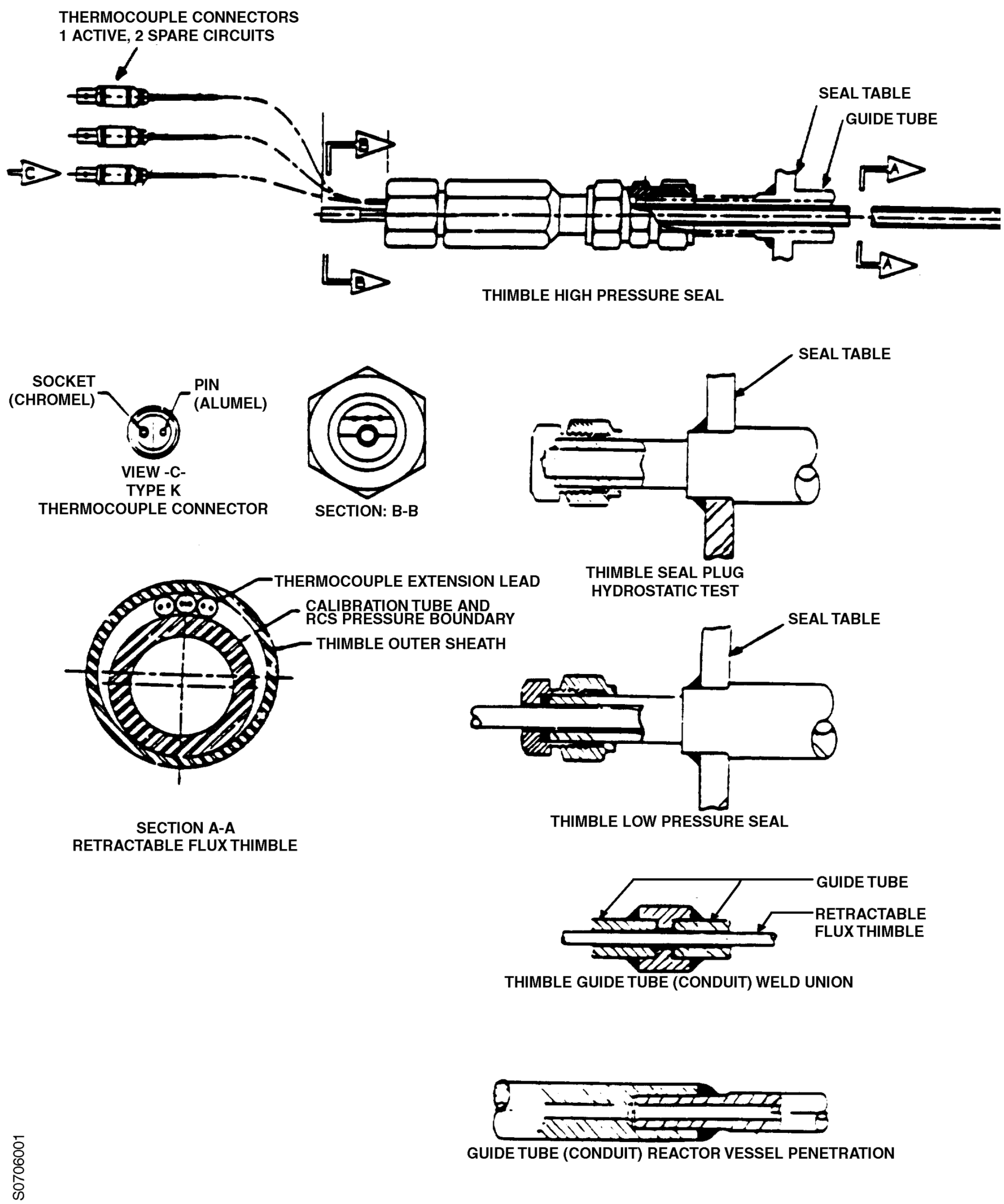
The control room contains the necessary equipment for control, position indication, and flux recording. Panels are provided to indicate the position of the detectors, and for plotting the flux level versus the detector position. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting, and gain controls. A flux-mapping operation consists of selecting (by panel switches) flux thimbles in given fuel assemblies at various core locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot (position vs. flux level) is initiated with the slow withdrawal of the detectors through the core from the top to a point below the bottom. In a similar manner, other core locations are selected and plotted.

Each detector provides axial flux distribution data along the center of a fuel assembly. Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

7.6.3 System Evaluation

The thimbles are distributed nearly uniformly over the core, with about the same number of thimbles in each quadrant. The measured nuclear peaking factor (F_Q) is increased by 8% to account for uncertainties, prior to being compared to its limit. An appropriate allowance for the measurement uncertainty for the nuclear hot-channel factor ($F\Delta h$) has been incorporated into the statistical DNBR limit. If either factor exceeds its limit, core power is reduced until the violation is eliminated.

Figure 7.6-1
INCORE INSTRUMENTATION - DETAILS WESTINGHOUSE DESIGN



Upon Completion of Design Change 00-003, this figure will no longer be applicable. The configuration of the flux thimble tubes will be as shown on Figure 7.6-2.

Figure 7.6-2
INCORE INSTRUMENTATION - DETAILS REPLACEMENT DESIGN

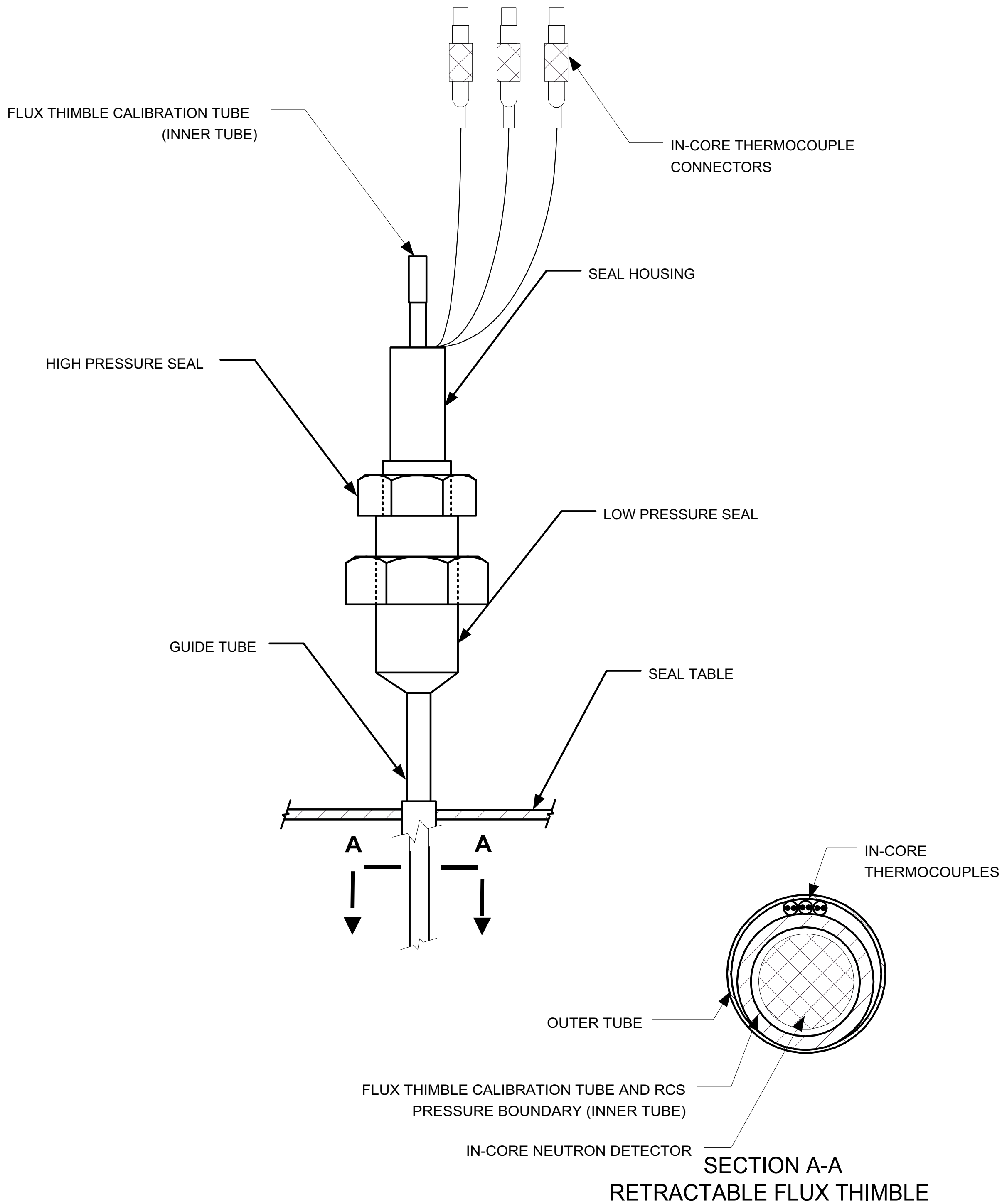
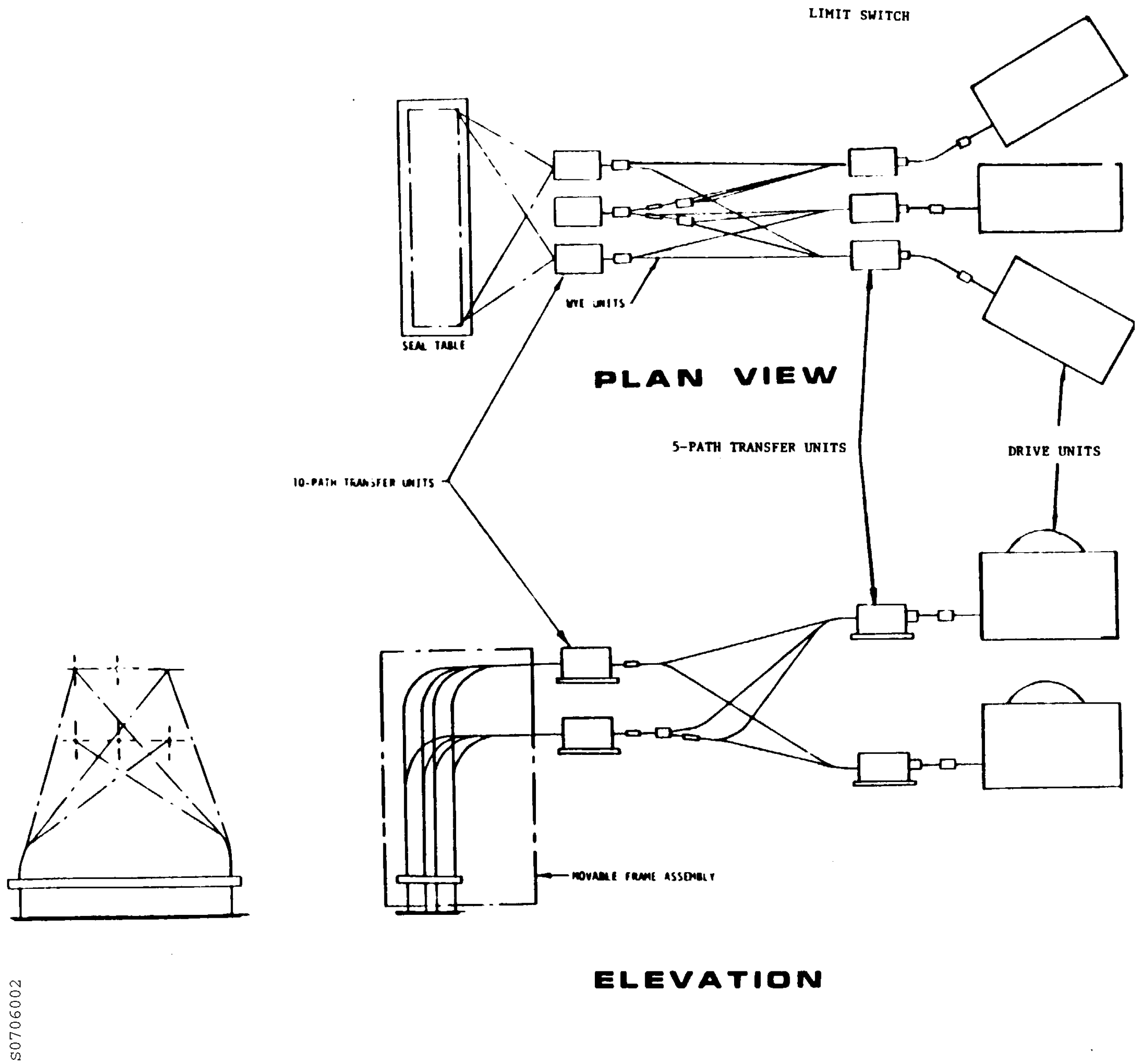


Figure 7.6-3
INCORE MECHANISMS



7.7 OPERATING CONTROL STATIONS

The control room, located in the service building, contains controls and instrumentation necessary to start up, operate, or shut down both units. It is one of the most important parts of the station, with pertinent interrelated information presented for the safe and reliable operation of the plant, including periods of transient and accident conditions. In the event that this area becomes inaccessible, the reactors can be brought to and maintained in a hot-shutdown condition at auxiliary control stations located in the Emergency Switchgear Rooms below the control room. There is a separate auxiliary control station for each unit. In addition, controls for certain auxiliary systems not directly involved with power generation, such as water treating and waste disposal, are located at remote control stations. The control room is shown in Figure 7.7-1 and Reference Drawing 1.

7.7.1 Design Bases

The station is equipped with a control room that contains controls and instrumentation necessary for operation of the reactors and turbine-generators under normal and accident conditions.

The control room, which is continuously occupied by qualified operating personnel under all operating and design-basis accident (DBA) conditions, is designed to permit single operator supervision of the units during normal steady-state conditions and to use additional operators to assist the control room operator during abnormal conditions.

The control room has three independent communication systems. One system consists of telephones leased from the local telephone company. These telephones and several outside trunk lines service the station for outside calls. This system may or may not be available under emergency conditions. A second system, a communication and voice paging system, is provided to interconnect the entire station. This system is energized from the emergency power buses. The third system is sound-powered, with telephone jacks and interconnecting wires at each major control point for test purposes. Sound-powered telephones are installed at various stations in the reactor containment. This system is accessible so that roving operators or service personnel may have easy communication with the control room or one another. This system does not rely on any power source, so it will be available at all times.

In addition to the above communications systems, onsite and offsite communications equipment has been installed to provide for notification of the NRC, as well as corporate, state, and local authorities on a 24-hour basis. A tri-band trunked radio system with redundant systems exists for radiological monitoring teams and security and recovery operations. Communications with the Corporate Emergency Response Center (CERC) are also provided on redundant systems.

Also, additional offsite communication equipment is installed and staged on-site using mobile satellite phones for a beyond design basis (BDB) event.

Sufficient shielding, distance, and containment integrity are provided to ensure that control room personnel shall not be subjected to doses that in the aggregate would exceed the limits in 10 CFR 50, Appendix A, GDC 19 during occupancy of, ingress to, and egress from the control room. All equipment in this area has been designed to minimize the possibility of a condition that could lead to possible inaccessibility or evacuation. For events analyzed to implement the alternate source term, which is described in Regulatory Guide 1.183, the control room dose limits are specified in 10 CFR 50.67.

The auxiliary control stations, also highly protected, are designed with a minimum of simple control actions required to bring and maintain the reactor in a hot-shutdown condition. It is not desirable to include marginal controls that would require more operator coordination, bypassing or deactivating of protective circuits, and unorthodox operating procedures.

Temperature in the control room and adjoining equipment room is maintained for personnel comfort at 75±10°F. The electronic equipment is tested and calibrated at the factory for the design temperature range from 40°F to 110°F. Qualification testing has demonstrated that the protective instrumentation remains operable up to 120°F, as there is a possible calibration shift above this range. The Plant Computer System equipment in the control room is designed to operate up to 95°F. This 120°F limit establishes the maximum temperature above which plant shutdown is required. Thus, there is a wide margin between design limits and the normal operating environment for control room equipment.

7.7.2 System Description

The primary objectives in the control room layout are to provide the necessary controls to start, operate, and shut down each unit, with sufficient information display and alarm indication to ensure safe and reliable operation under normal and accident conditions. Special emphasis is given to maintaining control integrity during accident conditions.

The equipment in the control room is arranged to reflect the fact that certain systems normally require more operator attention than others. The main control board is the central item in the control room. The control board for Unit 1 is completely independent of the control board for Unit 2. Each control board has a bench section, and a vertical section located behind the bench section. Most of the essential instruments and controls for power operation, and protective equipment that is immediately needed in cases of emergency, are mounted on the bench console sections in functional groupings. Recorders and indicators are mounted on the vertical back panels in agreement, wherever appropriate, with the functional groupings of the bench sections. The engineered safeguards section of the control board is designed to minimize the time required for the operator to evaluate the system performance under accident conditions.

Auxiliary vertical panels are provided in the control room, where their use simplifies control of certain auxiliary systems, or systems that only require occasional operator attention, such as turbine supervision, radiation monitoring, and liquid and gaseous waste disposal.

Illuminated window and audible alarm units are incorporated into the control room to warn the operator if abnormal conditions are approached by any system. Independent annunciator systems for each unit have their own identifying alarm horn tones. Indications and alarms are also provided so that the control room operator is made aware of any deviation from normal conditions at remote control stations. Many of these conditions are also alarmed by the unit performance-and-alarm monitoring system. Audible containment alarms are initiated automatically by the radiation monitoring system. Audible alarms are sounded in appropriate areas through the station if high-radiation conditions are present.

Instrumentation and control equipment is designed with reliable components. The temperature in the control room and emergency switchgear and relay rooms may vary from 65°F to 85°F. Safety systems, such as process instrumentation, nuclear instrumentation, and relay racks will continue to function within design accuracy in ambient temperatures up to 120°F. In addition, a reliable source of electric power, described in Section 8.4.3, is provided to ensure continual operation of vital unit and station instrumentation. Emergency lighting is also provided. The control room is further discussed in Section 11.3.6.

Two 100% redundant air handling units, fed from different power sources, are provided for the main control room and emergency switchgear and relay room of each unit. Each air handling unit is supplied chilled water by one of two chillers connected to the same power source as the respective air handling unit. Since the main control rooms are common, if only one of the four control room cooling units remains operable, the control room temperature will level off under 90°F. As the latent heat is negligible, humidity is not a factor. A double failure (both operating air-handling units failing concurrently) is required to jeopardize the temperature control. In this very unlikely event, the control room would reach 120°F in about 45 minutes, which would still provide sufficient time to start the redundant air handling units or shut down the reactor. Onsite testing was performed to prove the installed performance of the air-conditioning systems.

Qualification testing has been performed on various safety systems, such as process instrumentation, nuclear instrumentation, and relay racks. This testing involved demonstrating operation of safety functions at elevated ambient temperatures to 120°F for control room equipment and in full postaccident environment for required equipment in containment. Detailed results of some of these tests are proprietary to the suppliers, but are on file at the suppliers and available for audit by qualified parties.

The control room is designed to be available at all times. Accessibility to this area is from three points, thus ensuring entry for emergency personnel. Safe occupancy of the control room during an abnormal condition is provided for in the design of the service building. Adequate shielding and air conditioning are used to maintain tolerable radiation and air temperature levels in the control room. Ventilation consists of totally contained redundant recirculating air-conditioning systems designed to continue operation under all normal and emergency conditions. Fresh air intake and exhaust for normal use are from other independent systems, which can be valved off to stop the intake of airborne activity if monitors indicate that such action is appropriate. Makeup air, under emergency conditions, is available from emergency ventilating units supplying air through high-efficiency charcoal filters. With all normal outside air makeup shut off, the quality of the air will be maintained with the carbon-filtered emergency ventilation.

To limit the possibility and potential magnitude of a fire in the control room, the following are incorporated into its design:

1. Noncombustible materials are used in construction.
2. Control and instrumentation cable and switchboard wiring are used that meet the flame test described in Insulated Power Cable Engineers Association, Publication S-61-402, and National Electrical Manufacturers Association, Publication WC5-1968.
3. The main control boards are wired with flame-retarding switch-board-type conductors. The two main control boards are physically separated.
4. Control room furnishings are of metal construction with the exception of chairs, Corian desktops for the Senior Reactor Operator console and Plant Computer consoles, anti-fatigue flooring, and carpeting.
5. All control information is transmitted to the control room by electrical signals or low-pressure air signals. Transmitted signals from the containment structure and any other high-radiation areas are electrical.
6. Combustible supplies, such as records, logs, procedures, manuals, etc., are minimized.
7. Fire detection alarms are provided in the control room. These alarms are actuated from remote detectors sensitive to smoke and located in the vicinity of instrumentation cabinets, air-conditioning system ducts, and in other areas susceptible to fire.
8. All areas of the control room are readily accessible for extinguishing.
9. Portable fire extinguishers and breathing apparatuses are provided.
10. The control room is occupied at all times by an operator who has been trained in fire extinguishing techniques.
11. The control room is separated from the emergency switchgear and relay rooms by a 3-hour fire-resistant barrier. The emergency switchgear and relay rooms of each unit are separated from each other by a 3-hour fire wall.

Further description of the fire protection provisions is given in Section 9.10.

Therefore, any fires in the control room are expected to be of such small magnitude that they could be extinguished by a hand fire extinguisher. The resulting smoke and vapors are removed by the ventilation system. In addition, the control room is protected from outside fire, smoke, or airborne radioactivity by pressure-tight penetrations, weather-stripped doors, absence of windows, by the positive air pressure maintained in the area during normal operation, and by the ability to isolate the control room envelope during emergency conditions. Fire-rated doors are installed as access doors leading into the control room complex.

The probability of the control room becoming inaccessible as a result of fire or other causes is considered extremely small. However, if the operator must leave the control room, operating procedures require that he trip the reactors and turbine-generators before leaving so as to bring the station automatically to the no-load condition, thus ensuring control at the auxiliary control stations. Each reactor unit can be brought to and maintained in a hot-shutdown condition from its auxiliary control station, which is provided with the following alternate control provisions:

1. Removal of core residual heat.
2. Boration of the reactor coolant system.
3. Maintenance of pressurizer level and pressure.

These functions require the operation of auxiliary feedwater pumps, charging pumps, and boric acid transfer pumps. Appropriate process instrumentation, such as pressurizer pressure and level, and steam generator pressure and level, are provided in the auxiliary control stations. This equipment is sufficient to safely maintain the unit or units for an extended period of time in a hot-standby condition.

The principal point of control in the auxiliary control station is an instrument panel. The following equipment is controlled at this panel:

1. Turbine driven auxiliary feed pump start-stop control switch.
2. ‘A’ auxiliary feed pump motor start-stop control switch.
3. ‘B’ auxiliary feed pump motor start-stop control switch.
4. Motor-operated valves - auxiliary feed pump discharge open-close control switches (6).
5. Steam generator wide range water level indicators.
6. No. 1A charging pump motor start-stop control switch.
7. No. 1B charging pump motor start-stop control switch.
8. No. 1C charging pump motor start-stop control switch.
9. No. 1A boric acid pump motor start-stop control switch.
10. No. 1B boric acid pump motor start-stop control switch.
11. Charging flow control valve control switch.
12. Boric acid filter discharge to charging pump suction motor-operated valve control switch.
13. Pressurizer pressure indicator.
14. Pressurizer level indicator.

15. Pressurizer heater backup groups control switch.
16. Main steam header pressure indicators.
17. Main steam pressure indicators
18. Charging flow indicator

The capability of operating the residual heat removal pumps and component cooling water pumps from the emergency switchgear room, as discussed in Sections 9.3.2.1, 9.4.3.1, and 9.10.4.1, has been incorporated by the addition of a transfer switch and a control switch on each pump's breaker compartment at the switchgear. This capability, which has been incorporated in both units, has been installed to be used in the event a fire disables or causes evacuation of the control room. These plant features have been added in accordance with the requirements of 10 CFR 50 Appendix R.

Additional remote monitoring panels have been installed in the cable tray area of Unit 1. The panels provide indication of two reactor coolant loops hot- and cold-leg temperatures, RCS and steam generator pressures, pressurizer level, and steam generator wide range water levels, and source and wide-range excore neutron flux. The panels are shared by both units.[1] Signals to the panels are transmitted from instruments dedicated to the panel via cables independently routed from cables transmitting the same data to instrumentation in the control room and on the auxiliary shutdown panel.

Seismically-qualified transmitters are installed in the containments of each unit, parallel to existing RCS and steam generator pressure transmitters, and the pressurizer level, and steam generator wide-range level transmitters. Sensing lines for these transmitters are connected to the existing transmitter sensing lines, outside the crane wall, and are seismically qualified. The spare elements of existing dual head hot-leg RTDs are used and connected to temperature transmitters mounted in the remote monitoring panel. One element of the dual element cold-leg RTD's is used to provide the cold-leg temperature to the remote monitoring panel. Cables inside and outside the containment servicing the transmitters for the remote monitoring panel and spare RTD elements are routed independently from the cables for associated parallel transmitters and RTD element, furnishing identical information to control room and auxiliary shutdown panel instrumentation. In order to meet the requirements of 10 CFR 50 Appendix R additional transmitters and cables providing indication at the remote monitoring panels for RCS pressure, pressurizer level, and steam generator wide-range water levels have also been installed. Instrumentation sensing lines are routed independently with fire barriers as required to maintain specific separation from at least one parallel channel of indication available in the control room or auxiliary shutdown panel. This separation meets the requirements of Appendix R.

---

1. Panel RMP is powered from either unit's Appendix R Distribution Panel by a selector switch. Panel ASC-RMP, Unit 1 section is powered from Unit 2. Panel ASC-RMP, Unit 2 section is powered from Unit 1.

One remote monitoring panel (ASC RMP-1) contains one indicator for each of the following RCS parameters with a selector switch which aligns the indicator to either the Unit 1 or Unit 2 instrument transmitter outputs.

Steam Generators A, B, and C Wide-Range Levels

Pressurizer Level

RCS Wide-Range Pressure

RCS Loop 1 Hot-Leg Temperature (Units 1 & 2)

RCS Loop 2 Hot-Leg Temperature (Unit 1)

RCS Loop 3 Hot-Leg Temperature (Unit 2)

The 120V ac power from the Appendix R Panels is isolated by a selector switch, which aligns to either Unit's power, and protective relays. Loss of either unit's power at the panel is alarmed by an annunciator on the auxiliary ventilation panel (VNTX) which is shared by both units in the main control room.

The second remote monitoring panel (PNL-REM) contains six indicators for each unit. Indicators are provided for:

Steam Generator A Pressure

Steam Generator B Pressure (Unit 1 only)

Steam Generator C Pressure (Unit 2 only)

RCS Loop 1 Cold Leg Temperature

RCS Loop 2 Cold Leg Temperature (Unit 1 only)

RCS Loop 3 Cold Leg Temperature (Unit 2 only)

Source Range Neutron Flux

Wide Range Neutron Flux

Power for Unit 1 instrumentation on each remote monitoring panel is supplied by the Unit 2 Appendix R power system. Similarly, the Unit 2 instrumentation is supplied by the Unit 1 Appendix R power system. This assures that power will be available to the instrumentation of the affected unit following a fire in that unit's emergency switchgear room, cable tunnel or cable vault. Power to both Remote Monitoring Panels can also be supplied by a portable generator should power be lost to both Unit 1 and 2.

Alternative shutdown instrumentation for either unit's reactor is provided by the remote monitoring panels, which can be used in conjunction with the operation of the unaffected unit's charging pumps and the manual operation of applicable valves in the affected unit. The panels are to be utilized in the event that a fire disables the instrumentation on the affected unit's main board and auxiliary shutdown panel.

Should an Extended Loss of AC Power (ELAP) occur to both Units, backup power to both Remote Monitoring Panels is available for 12 hours via uninterruptable power supply (UPS). This ensures continuous monitoring capability is available until a portable generator can be deployed.

7.7.3 System Evaluation

7.7.3.1 Control Room

The control room is designed to provide the operator with the controls, indication, and alarms necessary to control the station during normal or abnormal conditions.

Necessary information is available to the operator in the control room following a LOCA. Monitored information is available for postaccident analysis.

7.7.3.2 Detailed Control Room Design Review

NUREG-0737, "Clarification of TMI Action Plan Requirements" (Reference 1), published in October 1980, provided a comprehensive and integrated plan to improve safety at power reactors. NUREG-0737 item I.D.1, "Control Room Design Reviews," required the development of a Detailed Control Room Design Review (DCRDR) to identify and correct control room design deficiencies. The NRC subsequently issued Supplement 1 to NUREG-0737 (Reference 2) to clarify and replace the previous DCRDR requirements in NUREG-0737.

In accordance with NUREG-0737 Supplement 1, Vepco submitted a DCRDR Program Plan (Reference 3). This was confirmed by the Commission's Order dated June 12, 1984 (Reference 4). Surry performed a human factors engineering (HFE) review of the SPS Units 1 & 2 control room. A Vepco letter from July 1984 (Reference 5) subsequently changed the DCRDR Program Plan by providing replacement pages reflecting the authorization of the use of the Westinghouse Owners Group Emergency Response Guidelines as the basis for the Task Analysis and the Verification and Validation activities. The result of the HFE review was submitted in a DCRDR Final Summary Report (Reference 6). This HFE review used the accepted human factors principles in NUREG-0700 (Reference 7) and NUREG-0801 (Reference 8) as guidance. The NRC reviewed the Vepco DCRDR Program Plan and Final Summary Report and concluded that Vepco's DCRDR program satisfied the requirements of item I.D.1 of Supplement 1 to NUREG-0737 (Reference 9). Following the initial NRC approval, a reassessment of the remaining DCRDR corrective actions were submitted (Reference 10, Reference 11, Reference 12) and approved in accordance with the NRC's safety evaluation reports (Reference 13, Reference 14).

The following HFE activities were performed as part of the initial SPS Units 1 & 2 DCRDR. These activities were required by the Commission's Order (Reference 4) which confirmed the commitment to implement a CRDR Program Plan per NUREG-0737 Supplement 1. The performance of these activities was reviewed and approved by the NRC, as documented in the NRC Safety Evaluation (Reference 9), per the guidelines set forth in Chapter 18.1 of NUREG-0800 (Reference 15) and other accepted human factors principles. These activities confirmed that the control room is capable of being used to safely operate the plant during emergency conditions.

- Operating Experience Review
- Control Room Survey
- System Functions and Task Analysis
- Control Room Inventory
- Verification of Task Performance Capabilities
- Validation of Control Room Functions
- Assessment of Human Engineering Deficiencies (HEDs)

7.7 REFERENCES

1. NUREG-0737 *Clarification of TMI Action Plan Requirements*, dated November 1980.
2. NRC Generic Letter 82-33, NUREG-0737 Supplement 1, *Requirements for Emergency Response Capability*, dated December 17, 1982.
3. *Control Room Design Review Program Plan for North Anna and Surry Power Stations*, Virginia Electric and Power Company, date March 1984 (ML18141A530).
4. NRC Confirmatory Order dated June 12, 1984, *Implementing Post TMI DCRDR* in Supplement 1. to NUREG-0737 (enclosure to Generic Letter 82-33) (ML012470030).
5. VEPCO letter of 7-27-84 providing replacement pages for the *DCRDR Program Plan*. (ML18142A021).
6. *Control Room Design Review Final Summary Report* (SPS) Volumes 1 and 2, March 1986 (ML18130A411).
7. NUREG-0700, *Guidelines for Control Room Design Review*, dated September 1981.
8. NUREG-0801, *Evaluation Criteria for Detailed Control Room Design Revie*w, dated October 1982.
9. NRC letter *Safety Evaluation for Detailed Control Room Design Review (DCRDR): North Anna Power Station, Units 1 and 2 (NA-1&2) and Surry Power Stations, Units 1 and 2 (Surry-1&2) (Tac Nos. 56142, 56143, 56170 and 56171*), dated February 1990 (ML20012A053).

10. Vepco letter *Virginia Electric and Power Company Surry Power Station Units 1 and 2 Control Room Design Review Corrective Action Reassessment Results*, dated July 1992 (ML18150A452).

11. Vepco letter *Virginia Electric and Power Company Surry Power Station Units 1 and 2 Control Room Design Review Reassessment – Response to Safety Evaluation Open Item and Identification of Design Change Discrepancies*, dated May 1994 (ML18153A955).

12. Vepco letter *Virginia Electric and Power Company Surry Power Station Units 1 and 2 Control Room Design Review Alternate Indication Clarification*, dated July 1994 (ML18153B024).

13. NRC letter *Surry Power Station Units 1 and 2 – Safety Evaluations Regarding the Detailed Control Room Design Review Reassessment (TAC Nos. M84511 and M845512)*, dated April 1993.

14. *Safety Evaluation by the Office of Nuclear Reactor Regulation – Detailed Control Room Design Review Reassessment for Surry Power Station Units 1 and 2*, Nuclear Regulatory Commission, dated October 1994 (ML18153B113).

15. NUREG-0800, *Standard Review Plan,* Section 18.1*, Control Room*, dated September 1984.

7.7 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FE-27A	Arrangement: Main Control Room, Elevation 27'- 0"

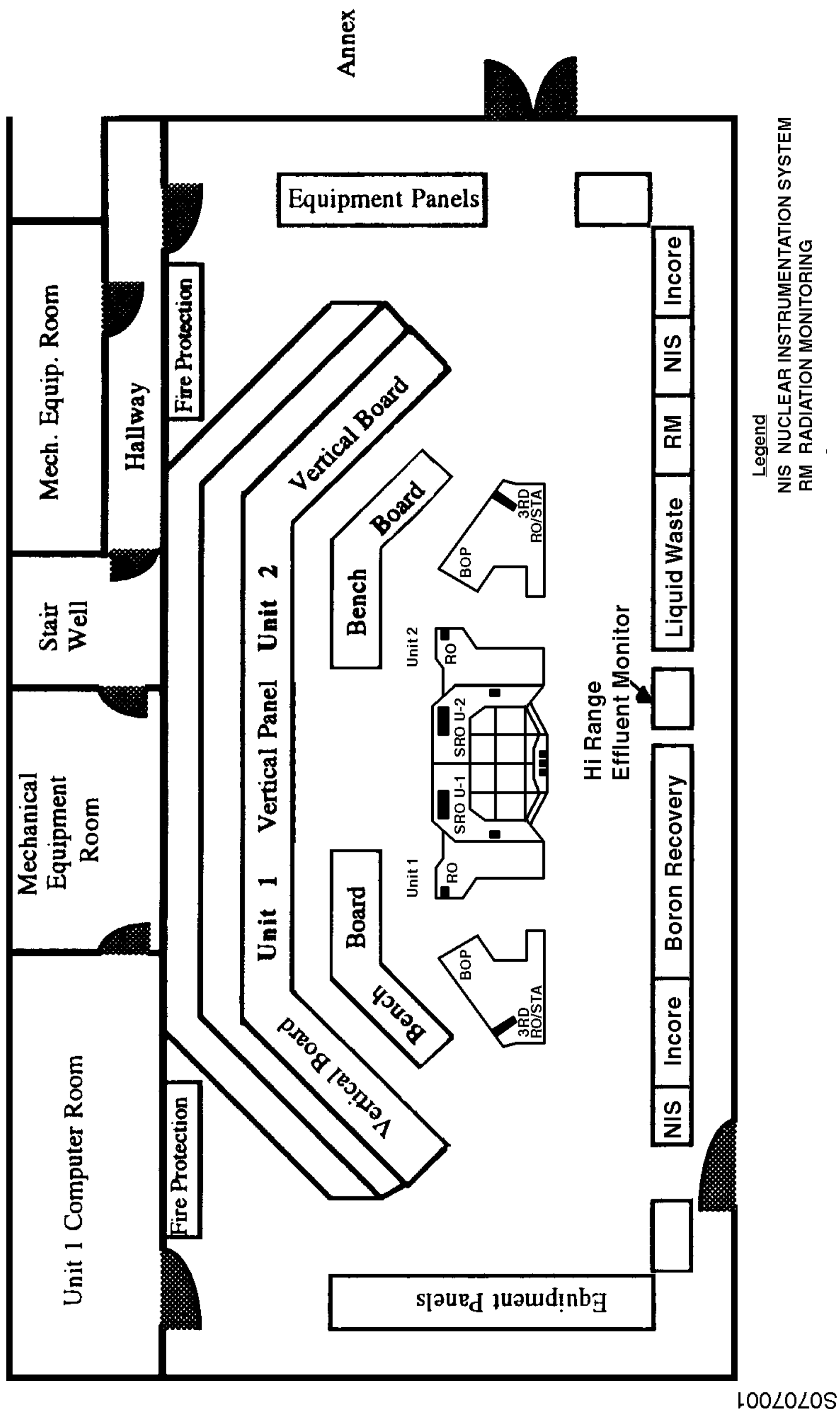


Figure 7.7-1
MAIN CONTROL ROOM ARRANGEMENT

Intentionally Blank

7.8 COMPUTER SYSTEM

7.8.1 Design Bases

The main purposes of the computer are to provide supplementary information to the operator, to effectively assist him in the operation of the nuclear steam supply system and turbine-generator cycle of each unit, to inform him of off-normal conditions, and to provide data communication, display and control functions for non-safety related equipment at the Low Level Intake Structure. The design of the control boards provides the operator with sufficient information for proper and safe operation of the unit if the computer system is unavailable.

7.8.2 System Description

The Plant Computer System (PCS) is designed to obtain data by scanning analog and digital field sensors and retrieve data from the Emergency Response Facility (ERF) data acquisition system, feedwater heater level control system and other peripheral plant systems. Operator (OWS) and Engineering (EWS) workstations act as primary data collection devices and then transmit that data to a secondary system historian, which will store easily retrievable data. Engineering workstations also provide the means to program the system. The PCS provides data and trending on visual displays, which can be printed. The system has the capability to log trip and post-trip data, and alarm when various off-normal conditions exist. Monitoring programs are also included for surveillance of reactor control and protection system operations and for nuclear process calculations and performance checks of systems and components. In addition to operator support functions, the PCS also serves as the Emergency Response Facility System, fulfilling the requirements of NUREG-0737 and NUREG-0696.

7.8.2.1 **Analog Scanning**

The computer continuously scans all preselected analog inputs at rates consistent with system requirements. Provisions are included for scanning some points faster than others. Those inputs that can change rapidly, or those associated with safety of the unit and associated with trip functions, are scanned at a rate suitable for detecting abnormal changes.

A limit-checking program is provided for determining that the analog values are within allowable instrument ranges. Out-of-range inputs are recorded and documented.

7.8.2.2 **Alarming**

Multiple high and/or low alarm setpoints can be assigned to each analog input. During each scan cycle, the analog values are compared to the associated setpoints to determine if they are outside the preset limits. A value in alarm is printed out or displayed on the OWS alarm screen and accompanied by an audible signal.

When the off-normal point returns to normal, the system again prints out or indicates a suitable message to this effect.

For example, a Delta-Flux Alarm Program monitors delta-flux in the reactor core and alerts the operator when a delta-flux alarm condition exists. There are two alarm states. They are: (1) above a preset power level when delta-flux has exceeded its allowable limit, and (2) below this power level if the allowable limit has been exceeded for a preset cumulative amount of time in the past 24 hours. Either alarm condition will set a computer contact closure output to actuate an annunciator alarm on the main control board. The annunciator will not clear until both of the computer alarms have returned to normal. Additionally, the alarm screen on the PCS OWS will indicate the associated system alarm point has changed state and requires operator attention. Most PCS alarms do not go to the annunciator system. They are displayed on the PCS alarm screens only.

7.8.2.3 **Alarm Review**

The operator may request a printout of all off-normal alarm inputs. This alarm review program documentation is very useful to a new shift, or for the operator to quickly determine the status of all station measurements.

7.8.2.4 **Analog Trend**

The analog trend function is used for recording suspected fluctuations or ramps in any measurements, or for obtaining data for future analysis of transients during start-up or load changing.

7.8.2.5 **Digital Trend**

The PCS provides visual displays of trends on the OWS. Any point in the system can be monitored on the workstation.

7.8.2.6 **Digital Display**

Visual displays are included on the operator workstations. Any analog input or addressable value can be displayed on this display.

7.8.2.7 **Sequence of Events**

These inputs usually are directly or closely associated with tripping the unit. A review of these events, in proper sequence, helps to analyze the causes and effects of unit trips and assists in trouble-shooting and returning the unit to service.

7.8.2.8 **Normal and Summary Logging**

Normal and summary logging for analog inputs, and calculated unit calorimetric variables, are provided.

7.8.3 System Evaluation

The PCS associated with each unit functions independently from the normal reactor control and protection system and engineered safeguards. The PCS provides control, communication, and display functions for non-safety related systems that do not provide reactor control functions.

Intentionally Blank

7.9 INADEQUATE CORE COOLING (ICC) SYSTEM

In response to NUREG-0578 (Reference 1), instrumentation to detect inadequate core cooling has been installed at Surry Units 1 and 2.

7.9.1 Design Bases

The Inadequate Core Cooling (ICC) system meets all the requirements of Regulatory Guide 1.97 (Reference 2). The ICC system, per unit, consists of the following three redundant subsystems that share common redundant calculator devices and continuous control room displays; Core Exit Thermocouple System, Core Cooling Monitor System, and Reactor Vessel Level Instrumentation System.

The system provides means for acquiring data only, and performs no operational unit control. Redundant displays in the control room graphically depict selected parameters, parameter trends, and system diagnostic information. An alarm is actuated in the control room on ICC system failure.

The safety-grade signal inputs, calculator devices and displays are qualified to IEEE-323 (Reference 3) or IEEE-344 (Reference 4).

7.9.2 System Description

7.9.2.1 **Core Exit Thermocouple (CET) System - Subsystem of ICC System**

The Core Exit Thermocouple System uses inputs from all the incore thermocouples to calculate and display temperature of the reactor coolant as it exits the core.

The CET system consists of Type K, grounded, stainless steel sheathed thermocouples. Refer to UFSAR Section 7.6.1, 7.6.2.1, and 7.6.2.2 for description of the quantity and design of the thermocouples.

One safety-related thermocouple from each flux thimble (25 for Train A and 25 for Train B) is wired to the redundant ICC calculators in the control room via the electrical penetrations and Station Multiplexer System.

The Cold junction compensation is performed internally at the remote multiplexer (MUX).

The thermocouples measure the core exit temperature in a range of 0 - 2300°F.

7.9.2.2 **Reactor Vessel Level Instrumentation Systems (RVLIS) - Subsystem of ICC System.**

The Reactor Vessel Level Instrumentation System (RVLIS) uses various parameters to calculate and to display the water level height in the reactor vessel during all plant conditions.

RVLIS uses differential pressure (d/p) measuring devices to measure vessel level or relative void content of the circulating primary coolant system fluid. The system is redundant and includes automatic compensation for potential temperature variations of the impulse lines. Essential information is displayed in the main control room in a form directly usable by the operator.

The functions performed by the RVLIS are as follows:

- Assist in detecting the presence of a gas bubble or void in the reactor vessel
- Assist in detecting the approach to ICC
- Indicate the formation of a void in the RCS during forced flow conditions

Refer to Figure 7.9-1 for the RVLIS schematic

The RVLIS utilizes two redundant sets of three differential pressure (d/p) cell transmitters. These cells measure the pressure drop from the bottom of the reactor vessel to the top of the vessel, and from the hot legs to the top of the vessel.

This d/p measuring system utilizes cells of differing ranges to cover different flow behaviors with and without reactor coolant pump operation as follows:

- Reactor Vessel - Upper Range. The d/p cell, LT1, shown in Figure 7.9-1 provides a measurement of reactor vessel level above the hot leg pipe when the reactor coolant pump (RCP) in the loop with the hot leg connection is not operating.
- Reactor Vessel - Dynamic Head Range. The d/p cell, LT3, shown in Figure 7.9-1 provides a measurement of the pressure drop across the reactor core and internals assemblies for any combination of RCP operation (1, 2, or 3 pumps running). Comparison of the measured pressure drop with the normal, single-phase pressure drop provides an approximate indication of the relative void content or density of the circulating fluid. This instrument monitors coolant conditions on a continuing basis during forced flow conditions.
- Reactor Vessel - Full Range. The d/p cell, LT2, shown in Figure 7.9-1 provides a measurement of reactor vessel level from the bottom of the vessel to the top of the vessel during natural circulation conditions.

To provide the required accuracy for level measurement, temperature measurements (T1 through T7) of the impulse lines are provided as shown on Figure 7.9-1. These measurements, together with the reactor coolant temperature measurements (hot leg RTDs) and wide range RCS pressure, are employed to compensate the d/p transmitters outputs for differences in system density and reference leg density, particularly during the change in the environment inside the containment structure following an accident.

The d/p cells are located outside of the containment to eliminate the large reduction (approximately 15%) of measurement accuracy associated with the change in the containments environment (temperature, pressure, radiation) during an accident. The cells are also located outside of containment so that system operation including calibration, cell replacement, reference leg checks, and filling are made easier.

7.9.2.3 **Core Cooling Monitor System - Subsystem of ICC System**

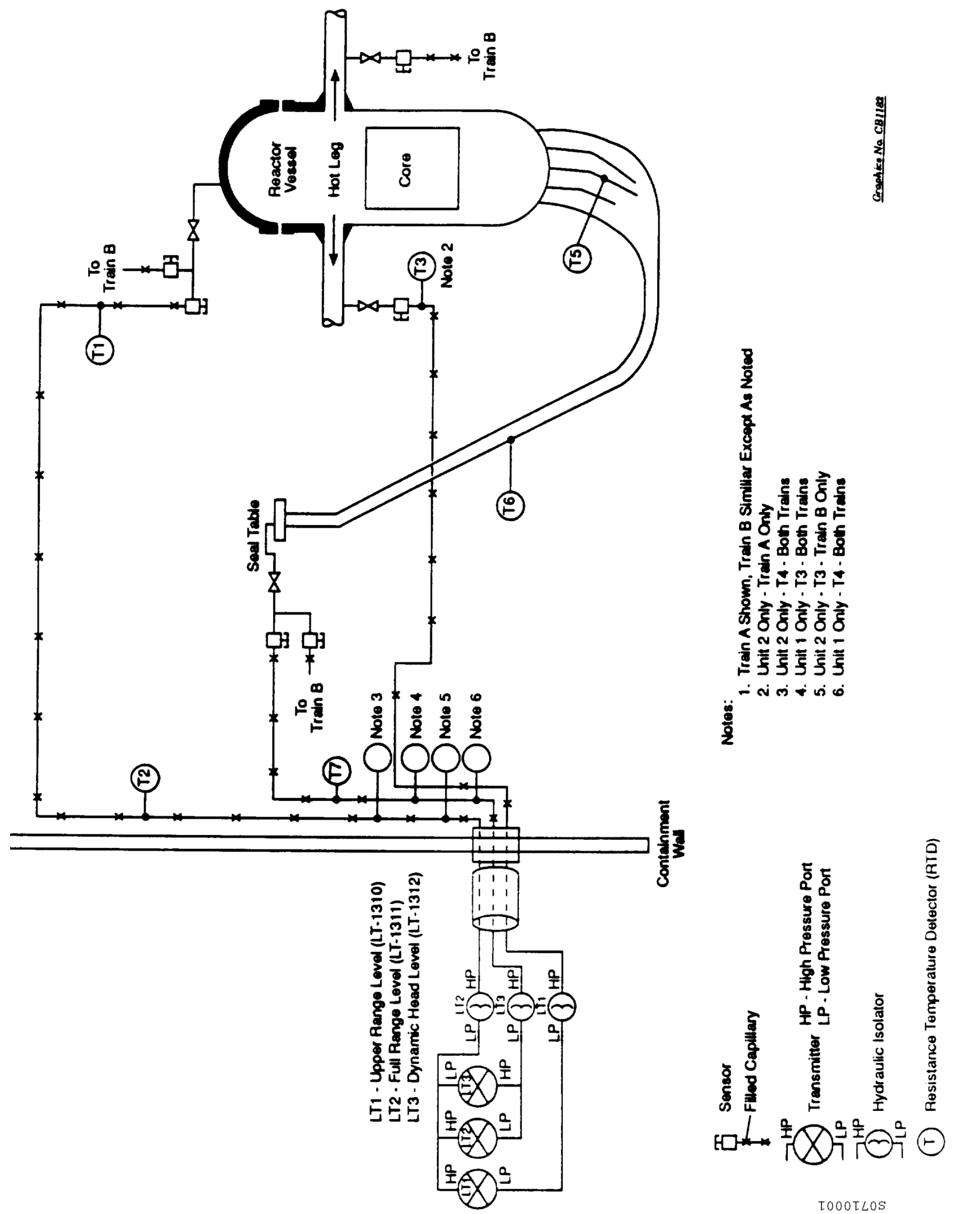
The Core Cooling or Subcooled Margin Monitor System uses various parameters to calculate saturation temperature and subcooled margins for the primary loops during all plant conditions. These input parameters provide the plant operators with complete information on core cooling.

Software algorithms determine the equivalent saturation temperature (T_{sat}) based on RCS wide range pressure. This (T_{sat}) value is used to determine the subcooled margin from the average of the five highest core exit thermocouples. An alarm is actuated in the control room on approach to saturation temperature.

7.9 REFERENCES

1. U.S. Nuclear Regulatory Commission, *TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations,* NUREG-0578, July 1979.
2. U.S. Nuclear Regulatory Commission, *Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident,* Regulatory Guide 1.97, December 1980.
3. IEEE Standard 323-1974, *IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations*, 1974.
4. IEEE Standard 344-1975, *Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations*, 1975.

Figure 7.9-1
REACTOR VESSEL LEVEL INSTRUMENTATION SYSTEM (RVLIS) SCHEMATIC



S0710001

7.10 EX-CORE NEUTRON FLUX MONITOR SYSTEM

7.10.1 Design Bases

The Ex-Core Neutron Flux Monitor System is designed to meet the requirements found in Appendix R of 10 CFR 50 and Regulatory Guide 1.97. These requirements are in addition to those used in the original design basis of the station.

The instrumentation required by R.G. 1.97 is redundant Category I, Seismic Class 1, and Class 1E. R.G. 1.97 requires wide range indication over a range of 10^{-6} to 100% of full reactor power. The system that has been installed provides Source Range Indication over a range of 0.1 to 10^5 cps and Wide Range Indication over a range of 10^{-8} to 200% of full power.

The portions of the system that are required to meet R.G. 1.97 requirements have been designed to meet IEEE-323-1974 and IEEE-344-1975.

7.10.2 System Description and Evaluation

The Ex-Core Neutron Flux Monitor System consists of two redundant Channels. These Channels are made up of detector assemblies, amplifiers and processor units and indicators.

The Ex-Core Neutron Flux Monitor is designed to provide to the operator the reactor neutron flux level from source level (shutdown) to 200% of full reactor power.

Fission chambers were chosen to monitor post-accident neutron flux because of their proven high reliability to a harsh environment and because of their relative insensitivity to a high gamma flux.

The signal from the detector is composed of a series of charge pulses. The pulses result from alpha decay of the uranium coating in the detector, from gamma photon interaction with material in the electrodes of the detector, and from the fissioning of uranium atoms when a neutron is absorbed. The pulse signal from alpha decay and from gamma radiation is an unwanted signal and can be eliminated by amplitude discrimination because the neutron pulse signal is much larger.

The number of pulses per unit time from the detector is proportional to the magnitude of the neutron flux at the detector. The magnitude of the neutron flux in the reactor core is proportional to the fission power being generated in the reactor. Since the magnitude of the neutron flux at the detector is proportional to the magnitude of the neutron flux in the reactor core, the pulse rate from the detector is proportional to reactor power.

The neutron flux monitor measures the number of pulses per unit time from the detector over the range from source level to the level where the error from countrate loss, due to coincident pulses, becomes unacceptable. From about two decades below the upper end of the countrate range to full reactor power, the neutron flux monitor measures the mean square value of the time variant signal from the detector. This mean square value is proportional to the average rate of neutron pulses and is not dependent on the pulses being individually identifiable, yet provides good discrimination against alpha and gamma signal.

The direct current signal from the detector provides a linear measurement of the reactor power. The direct current signal contains the alpha and gamma signal; however, on a linear scale from 0 to 200% of reactor power, it is less than 0.1% of full scale and, therefore, is not a problem. The direct current measurement inherently contains less statistical variation than the countrate or means square measurements and therefore, the measurement can be provided with a faster response time.

Source and Wide Range outputs from the Processor units are transmitted to the following locations (outputs are also available for the Technical Support Center):

Channel #1 (Red)	NIS Panel 1 Remote Monitoring Panel
Channel #2 (White)	NIS Panel 2

Indication at the NIS Panel and Remote Monitoring Panel consists of a set of two vertical edgewise meters. Displays for each area include both source range (0.1 to 10^5 cps) and wide range (10^{-8} to 200% of Reactor Power) neutron flux levels. They are intended to be available during all plant conditions.

The purpose of reactor power level indication is to confirm that the Reactor Shutdown function has been accomplished following an accident (in the case of the NIS Panel and TSC indicators), or fire (in the case of the Remote Monitoring Panel indicators).

In the event of a fire which requires the evacuation of the Control Room or causes the inoperability of control room reactor parameter indication, the Red Channel will be utilized to monitor reactor neutron flux level at the Remote Monitoring Panel.

The Ex-Core Neutron Flux Monitor System is also equipped with circuitry which provides continuous self-diagnostics of the integrity of the detector, cables, and power supplies. Failure of any of these components will generate a “non-operable” alarm in the Control Room.

The Ex-Core Neutron Flux Monitor System is normally supplied power from the 120V Vital AC Distribution System, Channels 1 and 2. In the event of a fire which causes the loss of control room indication and the normal electric distribution system, Channel 1 can be transferred to a back-up power source that is supplied from the other unit. In the event of a complete loss of ac power, a portable generator can be used to feed the Channel 1 Ex-Core system.

The system is designed so that all components which require calibration are located externally to the containment.

Should an Extended Loss of AC Power (ELAP) occur to both Units, backup power to the Channel 1 Ex-Core system is available for 12 hours via UPS. This ensures continuous monitoring capability is available until a portable generator can be deployed.

7.11 LEVEL INSTRUMENTATION TO PREVENT LOSS OF SHUTDOWN COOLING

In order to address concerns associated with loss of residual heat removal (RHR) capability while the Reactor Coolant System (RCS) is partially filled (i.e., mid-loop operation), a level standpipe has been permanently installed in the containment annulus to monitor reactor coolant level during plant shutdown and refueling.

An alternate means of determining the RCS level during mid-loop operation, which is independent of the level standpipe, is the ultrasonic measurement of the water level in the "B" hot leg piping.

7.11.1 System Description

7.11.1.1 Level Standpipe

The level standpipe is connected to the RCS at the top of the pressurizer and at a drain line from the Loop C cold leg. Local visual indication is provided at the standpipe in the containment annulus. Remote indication is also provided on the control room main board. An annunciator, which alarms on low reactor level, is also provided in the control room. The low level setpoint is set at a level prior to reaching RHR pump suction nozzle vortex initiation.

The standpipe and associated instrumentation is used only during shutdown and refueling conditions. During other plant conditions, the standpipe is isolated from the RCS by double isolation valves at each RCS connection.

7.11.1.2 Ultrasonic Level Indication System

An ultrasonic level indication system is installed as a secondary means of monitoring RCS drain down level independent of the level standpipe system. An ultrasonic transducer is mounted on the exterior of the "B" loop hot leg piping to provide RCS level indication. Remote indication is provided via a recorder located on the control room vertical board. A low level alarm is also provided by the ultrasonic level measurement which is connected to the standpipe low level alarm window. Either of the level measurement systems can activate the alarm on low RCS level.

The ultrasonic level indication system is only used in mid-loop operation during shutdown and refueling and is de-energized during normal plant operation.

Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 8

Intentionally Blank

Chapter 8: Electrical Systems
Table of Contents

Chapter 8: Electrical Systems

List of Figures

CHAPTER 8 ELECTRICAL SYSTEMS

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

8.1 GENERAL DESCRIPTION AND SUMMARY

The electrical systems include the equipment and the systems necessary to generate power and deliver it to the high-voltage switchyard. They also include facilities for providing power and controlling the operation of electrically driven auxiliary equipment and instrumentation. The main electrical connections are shown in Figure 8.3-1. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the electrical systems were found to be adequate.

This chapter describes the electrical system for Unit 1. The Unit 2 electrical system is identical but completely independent of Unit 1, with the exception of an emergency diesel generator common to both and used as a backup should the individual unit emergency diesel generators fail. The reserve station service transformer banks are common to both Units 1 and 2, and are sized to start up a single unit or to shut down both units.

The output of the main generator is fed into and operated as an integral part of the overall company electrical distribution system.

The normal station service power system is designed to provide continuous power to the station auxiliaries during periods of generation and to transfer automatically to the reserve station service power system to ensure continued power to equipment when the main generator is off the line.

The plant non-safety-related auxiliary systems are supplied by off site power during start-up, shutdown, or hot standby conditions. Safety-related auxiliary systems are normally supplied by offsite power during all modes of plant operation.

In general, all auxiliaries of major equipment will be connected to the same power distribution branch as the major pieces of equipment, the only exceptions being those appurtenances that will be required to operate when the major piece of equipment shuts down. An example is a pump discharge motor-operated valve that must be closed when the pump stops.

Critical instrumentation is fed from a reliable and stable vital bus system to ensure continuous monitoring and control of critical instrument channels.

There are no ac or dc circuits on safety-related systems that, upon voltage failure, automatically switch to an alternate bus energized from a redundant power source. There are provisions which ensure that, on loss of the normal power source to a particular bus, an alternate power source automatically is placed in service to supply the bus. These capabilities are discussed individually in the applicable sections.

Station batteries are provided for circuit breaker control power, emergency lighting, and operating power for vital equipment until normal power is restored or onsite emergency generation is available.

8.2 DESIGN BASES

The electrical systems are designed to supply electrical power to all essential unit equipment during normal operation and under accident conditions.

The main generator, described in Section 10.3.3, establishes the facility operating limits and requires the plant to be operated between a 0.905 lagging and a 0.96 (0.97 for Unit 2) leading power factor. As system reactive load changes, generator excitation can be adjusted to ensure operation within the required power factor limits. The system grid also has banks of shunt reactors that can be connected in order to adjust the power factor.

Electrical system components vital to unit safety, including the diesel generators, are designed and protected as necessary so that their integrity is not impaired by potential earthquakes, high winds, floods, or disturbances on the external electrical system. Cables, motors, and other electrical equipment required for operation of the engineered safeguards are suitably protected against the effects of either a nuclear system accident or a severe external environmental phenomenon, in order to ensure a high degree of reliability. The enclosures for motors and electrical switchgear are selected to suit the local conditions and are designed in accordance with specifications issued by the National Electrical Manufacturers Association (NEMA).

Essential electrical equipment components are specified to withstand, without loss of function, the maximum conditions expected during normal operating and post-accident environments, and during operation of the safeguard equipment during the accident. It is expected that the maximum accident conditions within the containment will be 280°F at 45 psig for 30 minutes. The environmental qualification of safety-related electrical equipment is discussed further in Chapter 7. Should suitable equipment not be available, the detailed plant design incorporates features to modify the environment to be compatible with the equipment.

In the containment, essential electrical components and conductors are protected from the forces generated during an incident by group separation. By physically separating each group and providing conductor barriers where necessary, the failure of one group does not jeopardize any other group. In the case of multiple instrument channels in one location, such as the channels associated with the single pressurizer, physical separation is carried out as far as possible and the circuitry arranged so that multiple instrument failures are always in the safe direction. Electrical cable connections are run from the instrument transmitter to the area outside the crane support wall using the shortest path while providing separation between redundant channels. The crane wall acts as a further barrier against any forces generated during an accident.

In general, the 4160V and 480V switchgear are of metal-clad deadfront construction with closing and tripping control power taken from the station batteries. Each starter or breaker cubicle is isolated from the adjacent cubicle with metal barriers, and each bus section is physically separated from all others. The main feeds to the 4160V switchgear from the unit station service transformers are shielded single conductors with volcanized chlorinated polyethylene based compound jacket installed in ladder type trays, with 1.00 - 2.00-diameter spacings between conductors. The cable portion of the main feeds to the 4160V switchgear from the reserve transformers A and B are hypalon jacketed with maintained spacing of 0.9 diameter to 1.0 diameter. RSST C main feed to the 4160V switchgear is TS-CPE (thermoset Chlorinated Polyethene) jacketed with maintained spacing between 1.25 diameter to 1.4 diameter. The RSST feeders consist of overhead bus and cable in cable tray. One reserve transformer feeder has separate routing to the 4160V switchgear, physically isolated from all other transformer secondary leads.

All switchgear associated with engineered safeguards equipment is separated from the main switchgear area and is readily accessible in the main control area. For all leads supplying engineered safety equipment, the cable is 3/c with interlocked armor overall, run in ladder trays or properly mounted and supported when run external to ladder trays, or 3-1/c triplexed, run in conduit, with the exceptions of the 480V equipment supplied from motor control centers and the emergency generator leads. The only 480V exceptions are for 30-hp motors and smaller. The emergency generator leads entering the emergency switchgear room from the duct bank have been derated for cable in conduit in accordance with Insulated Power Cable Engineers Association (IPCEA) standards. In Mechanical Equipment Room No. 5, power cables are installed in ladder type trays. In the emergency switchgear room, some of the cables have been run in ladder type trays which have solid covers placed directly on the top of the trays and may have a solid transite or asbestos blanket placed on the bottom of the trays prior to installation of cables. This installation has the same protection integrity as cable in conduit and facilitates installation and inspection of these critical cables.

Power and control cables are distributed from the switchgear and control area by means of rigid metal conduits or ladder type cable trays. Control cables are of single or multiconductor construction with insulation rated at 600 or 1000V and with overall flame-retardant jackets. Low-voltage instrument connections are made using flame-retardant insulated cables, rated at 300 or 600V. These cables are provided with a total coverage electrostatic shield and an overall flame-retardant jacket.

The normal current rating of all insulated conductors is limited to that continuous value which does not cause excessive insulation deterioration from heating. Selection of power conductor sizes are based on *Power Cable Ampacities*, published by the IPCEA. Feeder cables which are greater than 2000 MCM will have their continuous ampacity rating determined and derated utilizing References 1-6 as applicable. Cables using this method are derated for losses due to skin effect, proximity effect, eddy current, thermal losses due to jacket, insulation, dielectric losses and ambient air as well as derated for apparent tray depth for cables with top covers.

Fire-resisting fillers, tapes, binders, and jackets were specified for all cable construction. Cable tray installations have approved fire stops in both horizontal and vertical runs and are provided with a solid raised cover or a corrugated solid aluminum cover if minimum separation distance requirements between trays are not maintained. Covers may be omitted on top trays run under solid floors. All conduit installations consist of plastic conduit encased in concrete or exposed rigid metal conduit.

Electrical equipment and cables are specified such that the application is within the normal rating or temperature rise stated by the manufacturer. During normal operating conditions, electrical equipment or cables that are found operating in excess of the manufacturer's stated normal rating or temperature rise are analyzed for continued use.

All connections at the 22-kV voltage level are made with isolated phase construction designed for self-cooling.

The station batteries are sized to operate circuit breaker controls, instrumentation, emergency lighting, and vital nuclear channels for two hours without benefit of any station power. The battery chargers are connected to the emergency bus and provide charging current to the battery and load when the emergency bus is energized.

Lighting distribution and intensities have been selected in accordance with the recommendations of the Illumination Engineering Society (IES).

8.2 REFERENCES

1. *The Calculation of the Temperature Rise and Load Capability of Cable Systems*, Neher, J.H., and McGrath, M.H., AIEE Transactions, vol. 76, pt. Ill, pp. 752-764.
2. IEEE 835-1994, IEEE Standard Power Cable Ampacity Tables.
3. ICEA P-54-440 (NEMA WCS 1-2009), *Ampacities of Cables Installed in Cable Trays*.
4. ICEA S-93-639-2017 (NEMA WC 74), *5-46 kV Shielded Power Cable for Use in the Transmission and Distribution of Electric Energy*.
5. IEEE 525-2007, *IEEE Guide for the Design and Installation of Cable Systems in Substations*.
6. *Calculation of Current Division in Parallel Single Conductor Power Cables for Generating Station Applications*, IEEE Transactions on Power Delivery Vol. 6, No. 2.

Intentionally Blank

8.3 SYSTEM INTERCONNECTIONS

Unit 1 and Unit 2 are connected with the Vepco system at a transmission substation near the station. The connection is essentially a double one, since it is made through both the 230-kV and 500-kV transmission systems.

Electrical energy generated by Unit 1 at 22 kV is raised to 230 kV by the main transformer and delivered to the 230-kV switchyard. Electrical energy generated by Unit 2 at 22 kV is raised to 500 kV by the main transformer and delivered to the 500-kV switchyard by way of a motor operated air breaker (MOAB) and isolation breakers. The MOAB is located between the Unit 2 main transformer and the generator isolation breakers and permits the isolation breakers to be closed while Unit 2 is off the line. Reclosing the isolation breakers while Unit 2 is off-line is important for ensuring proper voltage levels are maintained offsite and hence grid stability. The MOAB is manually operated from the switchyard and is not designed to be operated under load. Control interlocks prevent the MOAB from being operated unless the isolation breakers are open. Figure 8.3-1 and Reference Drawing 1 are single-line diagrams of the transmission substation for the Surry Power Station.

The main generator feeds electrical power at 22 kV through an isolated-phase bus to the main step-up single-phase transformers and the unit station service transformers located adjacent to the turbine building. The primary side of each 22/4.16-kV station service transformer is connected to the unit isolated-phase bus at a point between the generator terminals and the low-voltage connection of the main step-up transformers. There are three station service transformers per unit. They supply three independent 4160V auxiliary buses and are designed to limit the short-circuit fault duty on any one bus to within the interrupting capability of the 250-MVA air circuit breakers.

During start-up and emergencies, reserve station service power for the auxiliaries of either unit is normally supplied from the Switchyard Transformers No. 1 (which is a 500/36.5-kV transformer that is connected to the 500-kV bus), No. 2, (which is a 230/36.5-kV transformer that is connected to the 230-kV bus #4), or No. 4 (which is a 230/36.5-kV transformer that is connected to the 230-kV bus #3). The 500-kV and 230-kV systems are independent and provide alternative sources of reserve power that can be expanded for future units and lines as required. Each Switchyard Transformer is capable to provide power to an Emergency Bus on each Unit.

The primary sides of the reserve station service transformers are connected to the 36.5-kV windings of either of Transformers Nos. 1, 2 or 4 in the high-voltage switchyard. During start-up, shutdown, or hot standby conditions, station service power is taken from the reserve station service transformers. The screenwell area is supplied through either of two 34.4-kV to 4.16-kV transformers, each of which is supplied from 34.5-kV Buses 5, 6, or 7 in the switchyard. Underground lines are installed to feed each screenwell transformer.

The 230-kV and 500-kV switchyards are of the “breaker and a half” design.

The normal operating ranges are from 220 to 245 kV for the 230-kV switchyard and 505 to 535 kV for the 500-kV switchyard. The emergency buses are serviced by transformers with automatic tap changers that ensure nearly constant load voltages during long-term grid voltage transients. The normal operating range on the emergency buses is 4200 to 4400V.

Two gas turbines are installed at the Surry site east of the 230-kV substation. One unit is rated at 16 MW and the other at 25 MW. These units are a part of the Vepco system and are primarily used for load peaking. One gas turbine has a black start capability with a start-up time of approximately 10 minutes. These two units are controlled and operated locally at the switchyard. The two generators are connected in parallel to the low-voltage side of a 13.2/230-kV transformer. Each generator has a breaker that is used for synchronizing and tripping. The high-voltage side of the transformer is connected to the No. 4 230-kV bus. Four additional combustion turbines rated at 82 MW each are located southeast of the switchyard. These units are controlled and operated independently of Surry Power Station, but their generators are connected to the transmission system via the 230-kV switchyard as shown in Figure 8.3-1 and Reference Drawing 1.

Transmission system connections for Unit 1 consist of the following lines, which are integral parts of the Vepco transmission system:

1. One 230-kV line to the Yadkin substation near Portsmouth, Virginia.
2. One 230-kV line to the Wards Creek substation in Disputanta, Virginia.
3. One 230-kV line to the Chuckatuck substation in Suffolk, Virginia.
4. One 230-kV line to the Churchland substation in Portsmouth, Virginia.
5. One 230-kV line to the Winchester substation in Hampton, Virginia.
6. Two 230-kV lines to the Gravel Neck Combustion Turbines, which are located near Surry Power Station.
7. One 230-kV line to the Colonial Trail substation in Surry, Virginia.

Additional transmission system connections for Unit 2 consist of:

1. One 500-kV line to the Septa substation near Surry, Virginia.
2. One 500-kV line to the Chickahominy substation in Providence Forge, Virginia.
3. One 500-kV line to the Suffolk substation near Portsmouth, Virginia.
4. One 500-kV line to the Skiffe’s Creek substation near Williamsburg, Virginia

Surry Power Station lies along two main transmission line rights-of-way. Each right-of-way includes transmission lines that principally route toward east and west locations in the Vepco system.

The transmission system can handle the full output of both units at Surry upon the loss of any two transmission circuits connected to the Surry substation. Figure 8.3-2 is a location map showing the Surry Power Station, associated transmission lines, and their system connections.

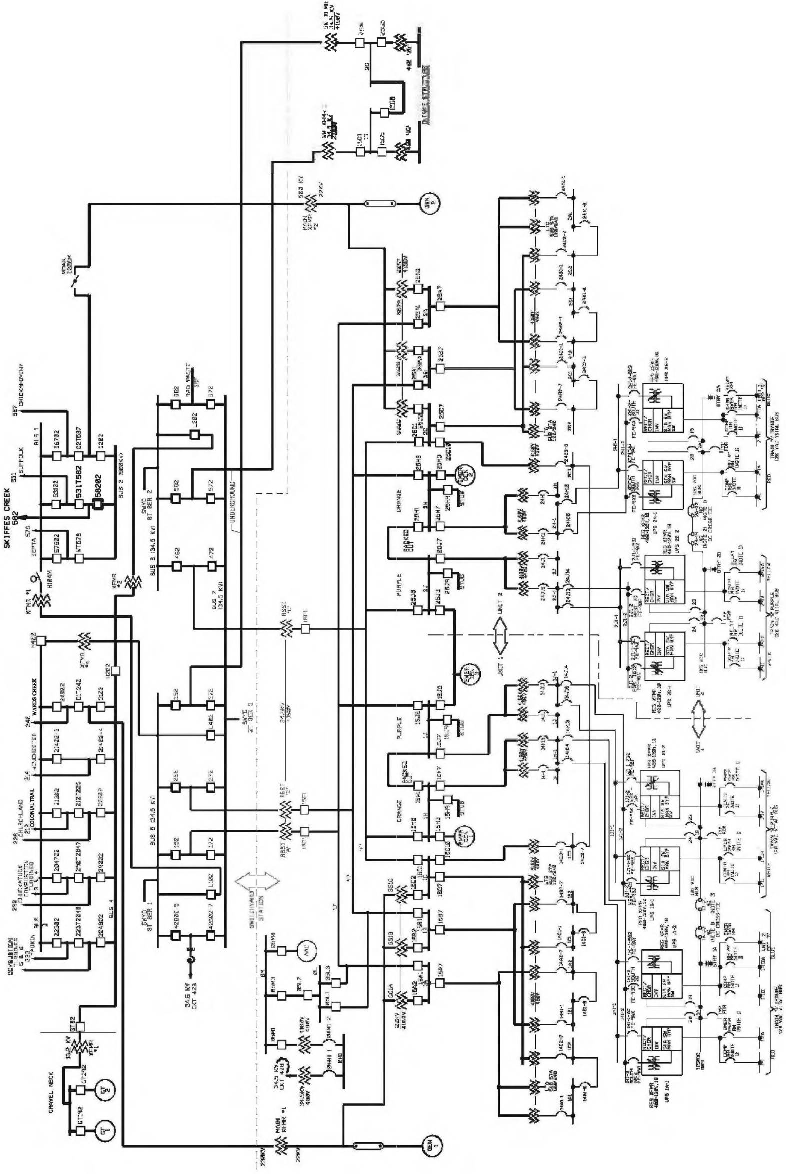
8.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FE-1A2	One Line Integrated Schematic, Electrical Power Distribution, Units 1 & 2

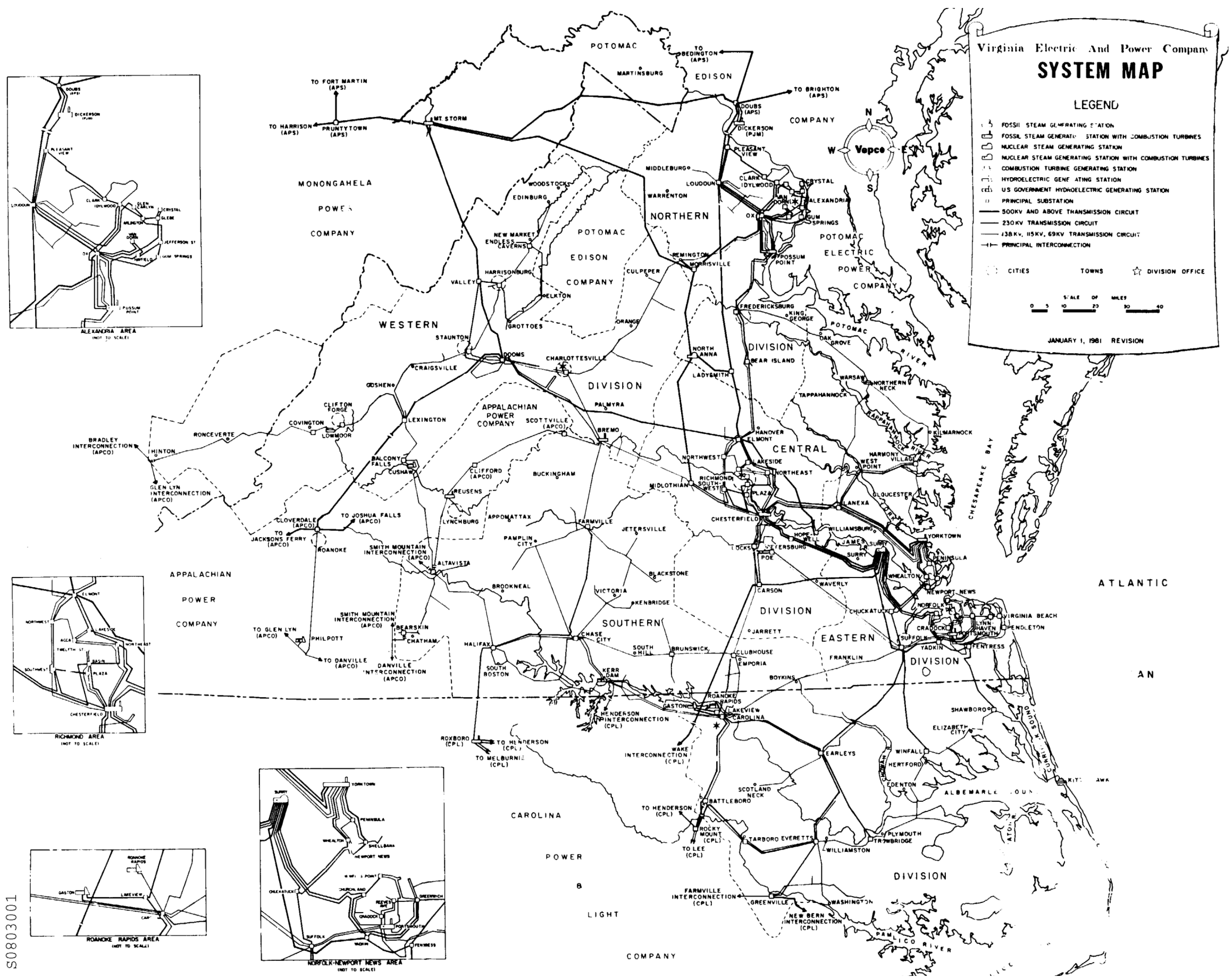
Figure 8.3-1
ELECTRIC POWER DISTRIBUTION

ELECTRIC POWER DISTRIBUTION



The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Figure 8.3-2
TRANSMISSION LINE MAP



Intentionally Blank

8.4 STATION SERVICE SYSTEMS

8.4.1 4160V System

Alternating current station service power is distributed from the 4160V switchgear. This switchgear is energized from the main generator and unit station service transformers during normal operation, or from the reserve station service transformer source during start-up, hot standby, or shutdown operation (Section 8.2). The 4160V system is duplicated for Unit 2.

The 4160V switchgear is arranged in three independent bus sections. Each bus section has a capacity of about 3000A. Each feeder or motor circuit is protected by overcurrent relays that trip the associated breaker for a sustained overload of a sufficient magnitude or a fault.

During unit start-up, the total ac demand of the unit is supplied from the reserve station service source. After the unit has attained operating conditions and the turbine generator is synchronized and connected to the system, the station service load is transferred to the unit station service transformers. This transfer is performed without a power interruption by momentarily feeding the 4160V switchgear from both the reserve and unit station service transformers. The feeds from the reserve station service transformers are then disconnected and the turbine generator will supply its own auxiliaries.

To include the possibility of two-unit simultaneous loading of the reserve station service (RSS) system, within its design capability, a load shedding system was installed to remove the overloads on the RSS system. This system provides for automatic load shedding of selected non-safety-related loads from both units which limits RSST loading to under 4000A per transformer. The scheme ensures that the voltages available on the emergency buses will be within acceptable limits. A manual override switch is provided in the control room to allow manual restarting of the shed loads under a controlled condition. With the addition of bus cooling, the transfer bus feeder breakers and adjacent bus cubicles (15D1, 15D2, 15E1, 15E2, 15F1, 15F2) are rated for 4000A continuously.

To improve the worst case voltage profiles due to large blocks of load receiving simultaneous starting signals under safety injection (SI) conditions and ensure the successful starting of safety-related loads, modifications to the secondary automatic load tap changers (ALTCs) on the reserve station service transformers (RSSTs), and automatic starting of selected large non-Class 1E loads were made. The modifications included:

1. Upon receipt of an SI signal or two unit load shed signal, the adjustable time delay of the RSST ALTC mechanisms will be bypassed. Under normal conditions the ALTCs are designed for a delay of approximately 30 seconds before the tap changing mechanisms react to a voltage change. The result in bypassing this feature is to enable the ALTC to react as quickly as possible to adjust the secondary RSST voltage to the preset level.

2. The automatic starting of selected large non-Class 1E loads is blocked. These loads that are prevented from auto starting are the condensate, bearing cooling, and component cooling pump motors. The auto-start block will remain in effect for 60 seconds following an SI signal and 315 seconds following a Consequence Limiting Safeguards (CLS) signal. This feature will prevent any voltage degradation of the emergency buses as a result of starting of non-Class 1E loads. These motors may be manually started, however, independent of the auto-start block.

Loss of normal supply to any bus section automatically trips the normal source breaker and closes the alternate source breaker.

Motors larger than approximately 300 hp are operated at 4160V and are arranged for across-the-line starting. One circuit from each bus section feeds two 4160/480V station service transformers. The 480V system is described in Section 8.4.2.

Two independent sections of emergency 4160V bus and switchgear are provided. Each section is sized to carry 100% of the emergency load. These emergency sections are energized from the reserve station service transformer during normal operation, start-up, and shutdown. In the event of total loss of offsite power, the emergency 4160V buses are isolated from the normal supply and energized from the diesel generators, as described in Section 8.5.

A manually operated air circuit breaker location is provided so that a 4160V emergency bus section may be connected to the redundant emergency bus section. This feature is used for maintenance or abnormal conditions only, and is under administrative control. The breaker will be tagged in the disconnect position for an operating unit.

8.4.2 480V System

The 480V ac station service system distributes and controls power for all 480V, 240V, and 120V ac station service demands. The source of power for the 480V ac system buses is from the counterpart 4160V ac system buses. The 480V ac system is divided into three double-ended bus sections, and each section is fed from a counterpart 4160V ac bus through individual 4160/480V ac station service transformers. This system is shown in Figure 8.3-1.

The switchgear is metal-clad, with 125V dc operated air circuit breakers, and arranged with six independent bus sections. The 4160/480V transformers are air-cooled.

Normal operation is with the bus sections independent of each other. Motors up to approximately 300 hp are connected to the 480V switchgear. Reduced unit output is possible with two 480V bus sections out of service.

Motor control centers are located throughout the station and are used for 480V power distribution and control of motors rated at 100 hp or less. In most cases, motor control centers are fed from 480V switchgear buses through breakers, while in some instances, motor control centers dedicated to a specific system are fed from other motor control centers via breakers due to physical space constraints and power supply requirements.

Engineered safeguards equipment items operating at 480V are fed from independent 480V buses and switchgear that are energized from either the reserve station service power or the diesel generators. When 480V emergency power sources are connected in a manner which would provide the capability of manually transferring loads from one source to a second source, isolation breakers are used upstream of the transfer switch to ensure that a single failure will not affect both power sources.

8.4.3 120V Alternating Current Vital Bus System

There are four separate 120V ac vital buses, each supplied by an independent 15 kVA inverter power supply. The inverter is housed within an electrical cabinet, which also contains a rectifier/charger, a static transfer switch, a manual bypass switch, and a voltage regulating line conditioner (RLC). This configuration is shown in Reference Drawing 1. The inverters are supplied in pairs by a common station battery. Each inverter pair and one battery form a safety train of uninterruptible power. There are two station batteries and inverter pairs per nuclear unit at Surry, which provide two independent redundant uninterruptible power supply (UPS) electrical trains. Normally, the inverter load is absorbed by the UPS rectifier/charger.

Upon rectifier/charger failure, the battery will pick up the inverter load. The UPS outputs are regulated automatically to a nominal 120V ac and 60 Hz. Upon inverter failure, the static switch will transfer the vital bus load to the RLC alternate source (120V ac, nominal) within 1/4 cycle.

The vital buses constitute a very reliable electrical system and provide a stable source of power to vital instruments and equipment. The redundant batteries are classified as passive components and are therefore subject to passive type failures. The definition of a passive failure is a failure which will not occur until after accident mitigation has entered the recirculation phase (post-RMT). Thus should a LOOP/LOCA occur, then the loss of a battery or dc bus will not credibly occur until after the unit enters the recirculation phase. For circuits that have been designed as energize to operate, analyses have been performed to ensure they meet the requirements for active component failure.

Each remote monitoring panel shares certain instrumentation from both units with the instrumentation from one unit being powered by the emergency power system of the other unit when vital buses are not available due to a disabling fire in the control room. This assures that indications of the selected parameters will be available for both units even if the fire disables the emergency power system of the affected unit. See Section 7.7.2 for additional discussion of this capability which was incorporated to satisfy the requirements of 10 CFR 50 Appendix R. In the event of a complete loss of ac power, a portable generator can be used to feed the Remote Monitoring Panels.

Should an Extended Loss of AC Power (ELAP) occur to both Units, backup power to both Remote Monitoring Panels is available for 12 hours via UPS. This ensures continuous monitoring capability is available until a portable generator can be deployed.

A modification to the vital bus voltage indication was accomplished to prevent a false indication of the loss of vital bus voltage. This could occur if the breaker used for the indication were inadvertently left open when the bus was energized. The modification provides for direct tapping of the vital bus via a 6A in-line fuse in lieu of the breaker.

The 120V, 60-Hz output of each UPS inverter is grounded and connected to two distribution cabinets. The distribution cabinets have 15A and 20A branch circuit breakers to feed reactor protection and other vital instrument channels. Reactor protective schemes have redundant channels and the power sources are provided from redundant vital bus cabinets.

Because of the fail-safe circuitry of the reactor protective instrumentation, a power source failure to an instrument channel results in a reactor trip signal from the affected channel. Multiple power supplies are provided to prevent a common power supply failure from initiating a false reactor trip.

The UPS are assembled from high-quality components, conservatively designed for long life and continuous operation. By avoiding the use of electromechanical devices, routine maintenance downtime is greatly reduced. There are no vacuum tubes or moving parts in the completely static vital bus supply system. Magnetic amplifiers, transistors, and silicon rectifiers are used to provide trouble-free operation.

8.4.4 125V Direct Current System

The Class 1E 125V dc batteries supply power for operation of switchgear, annunciators, vital bus inverters, and emergency lighting, as shown in Reference Drawing 2. The 1A battery provides 1 of 2 concurrent feeds to the Unit 1 main control room Hathaway annunciator. (The other concurrent feed is 120V ac from emergency diesel generator backed control room lighting panelboard 01-EP-LP-1C1.) The 2A battery provides 1 of 2 concurrent feeds to the Unit 2 main control room Hathaway annunciator. (The other concurrent feed is 120V ac from emergency diesel generator backed control room lighting panelboard 02-EP-LP-2C1.) The principal equipment items in this system are two nominal 125V dc lead-acid batteries, two UPS rectifier/charger, and two battery distribution switchboards.

The turbine generator emergency auxiliary oil pumps are connected to an independent black 60-cell battery powered from two static battery chargers supplied from normal motor control centers. Additionally, the normal power feed to the AMSAC inverter is from the same bus. The backup power feed to the AMSAC inverter is provided from a normal motor control center or an emergency motor control center via a transfer switch. This system is shown in Figure 8.4-1.

The batteries are of the central power station type and are designed for continuous duty. Each battery consists of a number of cells connected in series comprising a nominal 125V dc.

Each cell is of the sealed type, assembled in a shock-absorbing, clear plastic container, with covers bonded in place to form a leakproof seal. The batteries are mounted on protected, corrosion-resistant, earthquake-resistant racks for security and to facilitate maintenance. The two Class 1E battery areas are separated from each other and from the switchgear room.

Normally, the two battery bus sections are operated independently, with the bus tie breakers open. The UPS rectifier/chargers supply power for operation of equipment connected to that bus section and maintain a floating charge on the associated battery. The manually operated bus tie breakers provide for parallel operation of the bus sections with either battery out of service for maintenance.

The four UPS static battery rectifier/chargers (two per 125V-dc bus) are identical, each having an output of 350A at 130V dc with an input of 480V ac, three-phase. Each UPS rectifier/charger is equipped with a dc voltmeter, ammeter, ac failure relay, and low dc voltage alarm relay. Low ac or low dc voltage is alarmed in the control room. Battery bus ground indicators are located in the control room. Battery voltage is indicated to the operator on the main control board and continuously recorded on recorders located in the Emergency Switchgear Room. The UPSs are energized from emergency motor control centers.

The battery distribution switchboards are NEMA Class II metal-clad structures, each with a 125V dc, two-wire ungrounded main bus, and two-pole manually operated air circuit breakers.

During normal operation, the 125V dc load is fed from the battery chargers with the batteries floating on the systems. Upon loss of station ac power, the entire direct current load is drawn from the batteries. The batteries are sized for two hours of operation, after which it is assumed that station power or emergency generation power will be available to energize the battery chargers. The basis for sizing the station batteries for two hours without benefit of any station power is a carryover from the criteria used on non-nuclear power stations where emergency generators were not available to provide power to the battery chargers or turbine auxiliaries for safe coastdown. The batteries will be required for approximately 10 seconds between loss of station power and the availability of emergency ac power to supply the Class 1E battery chargers.

For each unit, a separate non-Class 1E battery, battery charger, and distribution switchboard are available for use in the screenwell structure.

8.4.5 Lighting System

Normal lighting for turbine areas, reactor containments, auxiliary building, fuel building, and service buildings is provided from local lighting cabinets located in the area of service. These cabinets except those for the control room, are fed from a double-ended lighting switchboard that is energized from two independent 250-kVA, single-phase, 4160-240/120V dry type, self-ventilated transformers. Normally the two buses of the double-ended switchboard are separate. They are capable of being tied together if one transformer fails.

The two control room lighting cabinets are each fed from local 37.5-kVA, single-phase 480-240/120V, dry type, self-ventilated transformers. The Unit 1 control room lighting transformer is supplied from the 480V 1H1-1 (Unit 1) bus and the Unit 2 control room lighting transformer is supplied from the 480V 2H1-1 (Unit 2) bus. The 1H1-1 and 2H1-1 emergency motor control centers are backed by different emergency diesel generators. Control room lighting cabinet (panelboard) 01-EP-LP-1C1 also provides 1 of 2 concurrent feeds to the Unit 1 main control room Hathaway annunciator. (The other concurrent feed is 125V dc from the Class 1E, 1A battery.) Control room lighting cabinet (panelboard) 02-EP-LP-2C1 also provides 1 of 2 concurrent feeds to the Unit 2 main control room Hathaway annunciator. (The other concurrent feed is 125V dc from the Class 1E, 2A battery.)

Normal lighting for the office building and remote areas is supplied through local 480-120/240V, single-phase, dry type transformers. Emergency lighting for remote areas is provided by local self-contained, battery-powered emergency lighting units.

Emergency lighting for turbine areas, auxiliary building, service buildings and various other locations is normally de-energized. These lights are automatically switched to the dc system upon sensing loss of voltage on the lighting switchboard. Emergency lighting for the reactor containment is energized at all times from an independent dc circuit. The turbine room operating floor also has an independent feed from the battery and automatically comes on if lighting intensity falls below certain levels. Emergency lighting feeds are provided from both units to the control room and turbine room mezzanine to provide the best possible protection.

Additional individually battery-powered emergency lanterns have been installed to facilitate access to and egress from the control room, emergency switchgear and relay rooms, service building cable vaults, cable tunnels, turbine building areas, mechanical equipment room no. 5, containment penetration cable vaults, diesel-generator rooms, first aid room and electric shop. These fixtures are automatically energized upon loss of normal ac bus power. They are powered from self-contained 6V or 12V batteries and static battery chargers, and use directionally adjustable lamps. The light fixtures are designed for eight hours.

Emergency lighting for the Technical Support Center (TSC) automatically transfers to the uninterruptible power supply (UPS) upon detection of the loss of the normal power source. Emergency lighting provides illumination for at least 15 minutes upon transfer to the TSCs UPS which will allow for an orderly shutdown of the Emergency Response Facility Data Acquisition System and exiting the area. The duration of emergency lighting for the TSC can be extended by manual transfer of the backup feed for the TSC UPS to the AAC diesel generator.

A post-fire emergency lighting system has been installed to facilitate operation and/or monitoring of safe shutdown equipment after a postulated fire in any area and access/egress routes thereto. This lighting system incorporates the use of the emergency diesel backed control room lighting system, diesel backed security lighting, self-contained 6V or 12V batteries and static charger units and emergency power units (consisting of self contained batteries, static charger and inverter) all located in the area served. Additionally, portable battery-powered lanterns are available for use in containment. This post-fire emergency lighting system will provide sufficient illumination for a minimum of eight hours to enable an operator to reach the safe shutdown equipment and perform required functions. Added equipment is seismically mounted in areas with safety related equipment and added cables are environmentally qualified in accordance with IEEE 323-1974.

8.4.6 Alternate AC (AAC) System

In response to 10 CFR 50.63, the Alternate AC (AAC) system was installed to provide ac power to one emergency bus on each unit during a Station Blackout (SBO) event. The AAC system is non-safety related and is designed in accordance with Regulatory Guide 1.155 and NUMARC 87-00, Appendix B.2.

The electrical design consists of a single 4160V ac diesel driven generator with a continuous rating of 3300 kW and a 2000-hour rating of 3640 kW. The generator is connected to the station via 4 kV buses 0M and 0L as shown in Reference Drawing 1. Bus 0L is located in the Unit 2 normal switchgear room and provides connection from bus 0M to transfer buses D and E which in turn allows connection to emergency buses 1J and 2H respectively. The diesel generator can provide power to the emergency buses within 10 minutes of determining that an SBO event has occurred and is sized to carry the loads necessary to bring both units to a safe shutdown condition and maintain them in a safe shutdown condition for the postulated 4 hour SBO event duration.

Following the loss of power on either the D or E transfer bus in conjunction with the loss of power on the F transfer bus, the diesel generator receives an automatic start signal. Momentary trip signals to breakers associated with the 0M and 0L buses ensure that the AAC system is initially isolated. Once the generator has reached proper speed and voltage, breakers automatically close to power buses 0M and 0L. Manual action is then required to energize transfer buses D or E. The normal power supply to the TSC UPS and the TSC MCC is from the Unit 2 “C” station service transformer or from RSST “C” via Transfer bus “F.” Following a loss of normal power supply, the TSC UPS and the TSC MCC can be powered from the AAC System via either transfer bus D or E following manual breaker re-alignment.

The AAC diesel generator is independent from the emergency diesel generators. The AAC diesel generator and its auxiliaries are housed in a separate building located south of the Radwaste Facility. The air start system contains sufficient capacity for 5 starts and the fuel oil system for the AAC diesel contains sufficient fuel to operate the diesel generator at 3640 kW for the postulated 4-hour SBO duration. To maintain the system in a standby state, a keep warm system consisting of a jacket water heater with a circulating pump and a lube oil heater with a circulating pump is provided. An ungrounded 125V dc system is provided for the 4 kV and 480V ac switchgear controls, diesel generator controls, and generator protection.

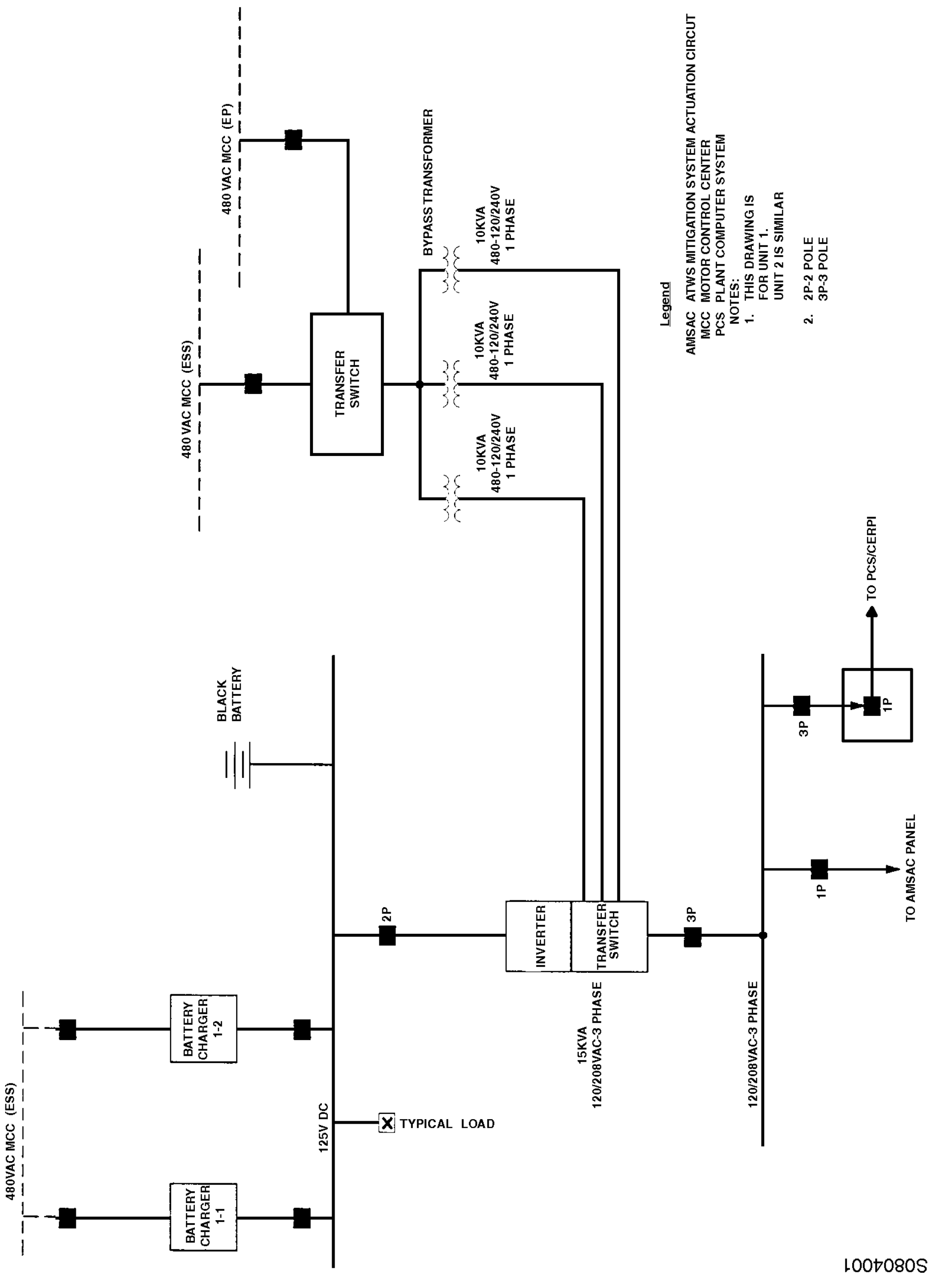
Annunciation is provided in the main control room to alert operators to alarm conditions. An “AAC System Trouble” alarm indicates that a malfunction or system protective action has occurred. An “AAC Diesel Generator Trip” alarm indicates that the diesel generator has tripped due to an engine or generator protective action. An “RSST A Parallel with RSST B” alarm indicates that the two RSSTs have been paralleled through Bus 0L. A “Bus 0L Trouble” alarm indicates that a protective relay actuation or a blown fuse alarm has occurred on this bus. In addition, a local annunciator in the AAC building provides additional details on alarm conditions.

8.4 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FE-1A2	One Line Integrated Schematic, Electrical Power Distribution, Units 1 & 2
2.	11448-FE-1G	One Line Diagram: 125V DC, Unit 1
	11548-FE-1G	One Line Diagram: 125V DC, Unit 2

Figure 8.4-1
BLACK BATTERY (125V DC) SYSTEM



Intentionally Blank

8.5 EMERGENCY POWER SYSTEM

The electrical power distribution system for the Surry Power Station provides duplicate systems for emergency components. Each system is continuously energized from the external system grid or from onsite diesel generators. The system is designed such that should a loss of offsite power (LOOP) occur, the onsite diesel generators will power the emergency power system. A loss of offsite power is defined as a loss of offsite power to both units (see Section 9.9).

Each unit has two 4160V emergency buses to supply safety-related auxiliary loads. These buses are normally supplied from the reserve station service transformers, as described in Section 8.3. The reserve station service transformers have automatic tap changers, which ensure nearly constant load voltages during long-term grid voltage transients. Tap changing is activated by any excursion in the reserve station service transformer output voltage, outside of the load tap changer setpoint range, that lasts for greater than 30 seconds. Upon activation, the load tap changer can step, approximately once every 2 seconds for up to 16 steps from neutral, in either the increase or decrease direction to restore transformer output voltage. The change increments average 0.625% of the neutral tap voltage per step. Emergency bus loads are designed to operate within ±10% of rated voltage, and the automatic tap changer configuration maintains emergency bus voltage within this range.

The circuits that supply power to the emergency buses through switchyard Transformers Nos. 1, 2, and 4 are known as “primary sources.” Each primary source is capable to provide power to an Emergency Bus on each Unit.

In addition to the “primary sources,” each unit has an additional offsite power source, which is called the “dependable alternate source.” This source can be made available in eight hours by removing a unit from service, disconnecting its main generator from the isolated phase bus, and feeding offsite power through the main step-up transformer and normal station service transformers to the emergency buses.

In the event of a complete loss of ac power and no emergency diesels, only dc power from the batteries is available. The only equipment operable would be the steam-driven auxiliary feedwater pump for maintaining makeup to the steam generator, and core heat removal, and the instrumentation supplied by the four vital buses whose power is supplied by the dc/ac inverters. There would be a dc lube-oil pump oil supply to the main turbine and the seal-oil pump oil supply to the main turbine and seal of the system for the main generator. Only natural circulation of reactor coolant would be possible, and makeup to the primary would require restoration of power to the ac emergency buses. The procedures used for station blackout and restoration of transmission systems are considered adequate to cope with the postulated event.

As a backup power source for the emergency buses, an onsite, independent, automatically starting emergency power system is provided. It supplies power to vital auxiliaries if a normal power source is not available and consists of three diesel generators for the two units. The Unit 1 diesel generator and the Unit 2 diesel generator are dedicated to emergency buses 1H and 2H, respectively. A third diesel generator is provided as a “swing diesel” and is shared by Units 1 and 2. Each diesel generator has 100% capacity and is connected to independent 4160V emergency buses. The third diesel is configured to preferentially load to the Unit 2 4160V bus (J Bus) with a loss of offsite power without a SI. If a unit experiences an SI signal that unit’s J Bus will be energized by the third diesel. The Unit 1 and Unit 2 diesel generators also supply power for certain common or shared plant systems/components, such as the Auxiliary Feedwater System pumps and cross connect valves, the Main Control Room and Emergency Switchgear Room (MCR/ESGR) Air Conditioning System chillers and air handling units, MCR/ESGR Emergency Ventilation System fans, Auxiliary Building Ventilation System fans, and the Containment Hydrogen Analyzers.

Each emergency bus provides power to the following operating engineered safeguards equipment:

1. One containment spray pump.
2. One charging pump (high-head safety injection pump). Two charging pumps on ‘H’ Bus (only when normal offsite power is available).
3. One low-head safety injection pump.
4. One recirculation spray pump inside containment.
5. One recirculation spray pump outside containment.
6. One motor control center for valves, instruments, control air compressor, fuel-oil pumps, etc.
7. Control area air-conditioning equipment—two air recirculating units, one water chilling unit, one service water pump, and one chilled water circulating pump.
8. One charging pump service water pump for charging pump intermediate seal coolers and lube-oil coolers.
9. One motor-driven auxiliary feedwater pump.

Safeguards equipment items are duplicated and connected to separate emergency buses. In the event of an equipment failure on one emergency bus coincident with a diesel-generator failure on the other bus, it is possible to connect both electrical buses to one generator so that the equipment normally powered from one diesel generator could be powered from another diesel generator if required. The emergency connection would be made under strict administrative control by manual operation of the bus tie breaker. If the loss of normal power is not accompanied by a loss-of-coolant accident, the safeguards equipment is not required. Under this condition, other plant auxiliary equipment, such as a component cooling pump, residual heat removal pump, etc., may be operated manually up to the capacity of the emergency generators. Instrumentation is provided to indicate diesel-generator loading.

If any safeguard equipment fails to operate automatically, manual operation is possible from the control room or at the switchgear. The switchgear for each diesel generator is physically and electrically isolated from the switchgear for the other diesel generators.

Three of five water chilling units (chillers) and the associated auxiliaries in the main control room and emergency switchgear and relay room air conditioning system are capable of being powered from either one of two emergency buses. In addition to providing operational and maintenance flexibility, this manual transfer capability ensures 100% air-conditioning capacity with any credible single failure.

It should be noted that one charging pump motor can be connected to either emergency bus. If an operator selects emergency bus H to energize the swing motor, he locks out the alternate circuit breaker connection to emergency bus J by means of a control switch on the main control board. In addition, a breaker mechanism interlock is provided to block closing of the alternate feeder breaker, when the selected breaker is closed.

Each diesel generator is reliable in operation. This reliability is achieved by use of duplicate or independent components or subsystems as follows:

1. Fuel system - Duplicate fuel systems with independent fuel and transfer pumps, strainers, and filters are provided.
2. Air supply starting system - Duplicate air starting systems with independent compressor, valves, and accumulators are provided.
3. Control storage battery - Each unit has its own independent control storage battery.
4. Control equipment - Each unit has individual control panels, metering, regulation, and excitation equipment.

Each diesel generator is provided with two starting subsystems. Each subsystem is sized for two engine starts without outside power. During automatic starts, both subsystems are activated to start the diesel generator. Each engine also has an independent day tank (combined base tank and auxiliary wall tank) with capacity for at least one hour of full-load operation. The auxiliary wall tanks are filled by transferring fuel from either one of two buried, tornado-missile-protected fuel-oil storage tanks, each having a 20,000-gallon capacity. Two 100%-capacity fuel-oil transfer pumps are provided for each diesel generator and are powered from the emergency buses to ensure that an operating diesel generator has a continuous supply of fuel. The buried fuel-oil storage tanks contain a 7-day supply of fuel (35,000-gallon minimum) for the full-load operation of one diesel generator. In addition, there is a 210,000-gallon above-ground fuel-oil storage tank onsite that is used for transferring fuel to the buried tanks. Provisions are in place to permit inspection and related repair of a buried fuel-oil storage tank during plant operation. While one buried tank is out of service, the verification of onsite and offsite fuel-oil sources is required to ensure an adequate supply of fuel-oil remains available.

The diesel engine starting circuitry accepts the following signals:

1. Undervoltage/degraded voltage or open phase condition on emergency bus.
2. Safety injection signal.
3. High-High consequences limiting safeguards.
4. Manual.

Conditions that render the diesel generator incapable of responding to an automatic emergency start signal are:

1. Diesel-generator output differential current fault.
2. Diesel-generator output overcurrent fault.
3. No diesel-generator field.
4. Overspeed.

(The above four conditions must be reset prior to any start.)

5. Manual stop from local or remote locations.
6. Control room switch in “exercise” instead of “auto.”
7. Engine control cabinet (at the diesel) switch in “local start.”
8. Necessary circuit breakers in “off” position.
9. Low starting air pressure.
10. Less than required fuel inventory.
11. Low battery voltage.

Alarms and annunciators actuate in the control room and the local diesel-generator control panel when a fault condition associated with the diesel generator exists. An emergency diesel auto-start-disabled alarm is obtained in the control room whenever the local diesel control panel selector switch is in the “local start” position or when the “auto-exercise” switch on the remote control room panel is in the “exercise” position. If any of the other disabling conditions exist, an emergency generator trouble alarm will be received in the control room.

If required, the emergency buses can be powered from the onsite diesel generators. During accident conditions, each diesel generator set is sized to start and accept load in equal to or less than 10 seconds of the start signal. The starting load capacity is 12,500 kVA. The diesel generators have a cumulative 2000-hour rating of 2750 kW. The allowable EDG loading will not exceed these values. Engineering controls and incorporates load additions into worst-case voltage profiles and load calculations to ensure EDG ratings are not exceeded. The starting, accelerating, and loading times of the diesel generators using simulated loads were witnessed and checked before the units were accepted from the engine manufacturer. The continued ability to accept load is tested as described in Section 8.6.

The emergency buses are protected from either a degraded voltage, a loss-of-voltage, or an open phase condition. The voltage of each bus is monitored on each phase with separate single-phase loss-of-voltage relays, two parallel three-phase degraded voltage relays, and three three-phase open phase relays. Each separate set of relays will provide the input to a coincident two-out-of-three logic scheme. The setpoints (setting limits) for these three protection schemes are provided in the Technical Specifications. The system operation is described below:

- Under degraded voltage conditions (nominally, below 92.7% of rated voltage), the two-out-of-three logic scheme will initiate an alarm in the control room at 10 seconds, start the diesel generators at 50 seconds, and initiate the transfer of the Class 1E emergency buses from the offsite source to the diesel generators at 60 seconds. If a safety-injection or consequence-limiting safeguards signal is concurrent with the degraded voltage, the 10-, 50-, and 60-second time delays are effectively bypassed. The diesel generator is started upon receipt of the safety injection or consequence-limiting safeguards signal and, following the degraded voltage signal 7-second delay, the transfer from offsite to onsite power is initiated. Upon transfer initiation with a safety injection or consequence-limiting safeguards condition, the offsite source feeder breakers to the Class 1E buses, the stub bus tie breaker, the residual heat removal pumps, the component cooling pumps, and one of the two “H” Bus charging pumps are automatically tripped.

- On a loss-of-voltage condition (nominally, below 75% of rated voltage), the separate relays will trip and, after a time delay, initiate an automatic transfer of the Class 1E emergency buses from the offsite source to the diesel generator. The time delay for this first level (loss-of-voltage) protection is nominally 2 seconds. Both this time delay and the nominal 7-second time delay for second level (degraded voltage) conditions, discussed above, meet NRC staff positions on undervoltage protection allowable time delays, in that they will allow for system voltage transients while ensuring that the diesel generator energizes the emergency bus within 10 seconds of the loss-of-voltage signal (assumed in the accident analysis), and they will not cause the failure of any equipment attached to, and associated with, the Class 1E power system.

- For an open phase condition (nominally, above 6% negative sequence voltage), the two-out-of-three logic scheme will energize an Undervoltage Protection auxiliary relay for the associated bus which starts the EDG and transfers following the same process as the Undervoltage/Degraded voltage protection scheme. The open phase condition negative sequence voltage relays include an inverse time characteristic which introduces a trip time delay based on the magnitude of negative sequence voltage sensed. A time dial setting of 10 is used for the open phase of less than 5 seconds for any open phase condition sensed at an emergency bus.

For degraded voltage, loss-of-voltage, and open phase conditions, once the diesel generator reaches the necessary voltage and speed (95 ±2% of nominal bus voltage and 870 ±20 rpm, respectively) and the 2.2-second residual voltage time delay is satisfied, the diesel generator output breaker will close. The time delay relay is actuated when the normal feeder breaker opens. This time delay, based upon analysis, is sufficient to permit residual bus voltages to dissipate to allowable levels and prevents equipment damage that could be caused by an out-of-phase transfer. Upon closing of the output breaker, the loss-of-voltage and under-voltage protection schemes are automatically bypassed so that automatic bus unloading will not occur. However, should the diesel-generator breaker(s) open, both protection schemes are automatically reinstated. The open phase protection scheme is blocked when the normal supply breaker is open.

Safety-injection and consequence-limiting safeguards conditions impact loading on the diesel generator. For a safety injection condition, the charging pump and low-head safety injection pump receive immediate starting signals. At 50 seconds after the safety injection, the steam generator auxiliary feedwater pumps are started. At approximately 90 seconds after the safety injection, the filter exhaust fans are started for a consequence-limiting safeguards condition, the charging pump, low head safety injection pump plus the containment spray pumps receive immediate start signals. In addition to the delayed starting of the steam generator auxiliary feedwater pumps, the filtered exhaust fans start at 90 seconds, the inside recirculation spray pumps start at 120 seconds and the outside recirculation spray pumps start at 300 seconds. On a loss of offsite power or open phase event, the emergency diesel generator load sequencing scheme is initiated to ensure that previously running loads are re-energized without exceeding diesel generator operational ratings. This scheme will trip certain loads, if they have been running, and resequence them onto the emergency bus - provided that all other breaker closure permissives are satisfied.

For running loads, the load sequencing scheme is independent of safety injection or consequence-limiting safeguards logic for the affected loads and, therefore, could be concurrent. The affected loads and their resequence times after EDG breaker closure upon LOOP are listed below.

1. Outside recirculation spray pumps are resequenced after 10 seconds.
2. Inside recirculation spray pumps are resequenced after 20 seconds.
3. Filter Exhaust Fans (1-VS-F-58A & B) are resequenced after 30 seconds.
4. Pressurizer Heaters are resequenced after 180 seconds.
5. Auxiliary feedwater pumps are resequenced after 10 seconds with only an SI signal present and after 140 seconds with hi-hi CLS signal present.

The design basis accident analysis discussed in Chapters 5 and 14 considers a loss of coolant accident (LOCA) to occur coincident with a loss of offsite power (LOOP). It is not necessary to evaluate potential impacts on the performance of other systems resulting from a

LOOP subsequent to a LOCA because that scenario is not part of the Surry licensing basis. NRC Information Notice 85-91, *Load Sequencers for Emergency Diesel Generators*, identified a potential problem with the diesel loading sequence if a LOOP should occur subsequent to a LOCA. Virginia Power evaluated this situation with respect to emergency diesel generator loading even though the Surry licensing basis considers the LOOP to occur coincident with the LOCA. The evaluation identified that, after implementation of appropriate modifications to emergency diesel sequencing logics, a LOOP subsequent to a LOCA would not result in overloading of the emergency diesel generators.

Voltage and frequency for the emergency diesel generators are automatically set. However, voltage and frequency can also be adjusted by the operator if outside of the procedural limits. Frequency is controlled to 59.67-60.33 Hz and voltage is controlled to 4000-4400 volts. These procedural limits have been used in hydraulic calculations for maximum horsepower and minimum and maximum flows that are used in the safety analyses.

The single failure of a dc system (e.g., station battery) can adversely affect the shedding of loads and opening of supply breakers in one emergency power system train. However, because of the redundant trains and the diverse dc supplies to the supply breakers, the system design would not be impacted to such an extent that adequate diesel generator operation could be prevented.

The degraded voltage setpoints were chosen to preclude inadvertent load shedding during transient undervoltage conditions that could potentially occur when large loads are started.

The emergency bus is protected (nominally, between 75% and 92.7% of rated voltage) from a degraded voltage condition after a 60-second time delay. However, safety-grade motors were purchased or analyzed to start at 70% of rated voltage (72% for LHSI pump motors 1-SI-P-1A and 2-SI-P-1A and 2-SI-P-1B); thus, the motors will all start and accelerate through the range of degraded voltage.

General Electric SAM timers have been added in the trip circuit of transfer breakers 15D1, 15El, and 15Fl. The timers provide a time-delay trip of 300 milliseconds if the normal feeder breakers to the emergency breakers do not trip. If they do trip, the timers are dropped out of the delay circuit allowing 15D1, 15E1 or 15FI to remain closed. This prevents a loss of power to transfer bus D, E or F due to an under-voltage condition that might exist on emergency bus 1J, 2H or either 1H or 2J, respectively.

Another level of undervoltage protection exists on the 4 kV transfer buses D, E and F. This protection system has a voltage setpoint greater than or equal to 46.7% of nominal voltage. Actuation of the relays will automatically start the auxiliary feedwater pump and align appropriate motor-operated valves under consequence-limiting safeguards.

An additional open phase detection system exists on Switchyard Transformer No. 1. This detection system monitors open phase events on the primary side of that transformer which may not be detected by the negative sequence voltage relays at the 4kV emergency buses. Actuation of this detection system will annunciate a trouble alarm in the main control room. Operators will diagnose and investigate the event.

Control circuits for safety-related loads are designed so that a degraded voltage will not adversely affect operation. All safety-related loads are operated either by circuit breakers or by motor controllers. The circuit breakers are supplied with 125V dc control power, which comes from the station battery bus. The 125V dc control power is supplied via fuses in the individual breakers. The original fuses were replaced by smaller fuses to allow for electrical coordination with the breaker in the 125V dc distribution panel feeding the entire bus. This change was necessary to conform to the requirements of Appendix R to 10 CFR 50 and assures availability of power sources to safe shutdown equipment. (See Section 9.10.3.4 for additional information.) Therefore, operation of these breakers is independent of emergency bus voltage. The motor controllers are supplied with ac control power from an internal transformer, which steps down line voltage to 120V ac. Therefore, motor controller operation is dependent on line voltage. Safety-related motor controllers will operate satisfactorily with line voltage at values greater than the undervoltage setpoint for diesel-generator loading.

Each piece of vital equipment is connected to the auxiliary electrical power system with an exclusive circuit. Each circuit has an air circuit breaker overcurrent fault protection, and a control switch with red, amber, and green indicating lights mounted in the control room. The red lights show that the power circuit is available. The green light is lit when the power circuit is de-energized and monitors the availability of control power. Simultaneous lighting of the amber and green lights indicates an automatic trip of a feeder or source circuit. Major items have meters to indicate circuit current. Isolation of a failed circuit is automatic and is identified by the indicating lights in the control room. Automatic tripping functions also energize an audible signal to alert the control room operator. Individual protective relays have signal targets to indicate that automatic operation has taken place.

Original plant design included two 4160/480V load center transformers per unit, 1H and 1J and 2H and 2J. With the addition of the 1H1, 1J1, 2H1 and 2J1 transformers, studies were performed in 1979 for Unit 1 (Reference 1) and in 1980 got Unit 2 (Reference 2) to confirm the load capability of the 480V emergency power system and to verify the adequacy of voltage profiles on Class 1E buses during various modes of plant operation. (The 480V emergency power system is shown on Figure 8.3-1.)

In accordance with the NRC Generic Letter (Reference 3), dated August 8, 1979, entitled *Adequacy of Station Electrical Distribution System Voltages*, Vepco performed analyses to determine the adequacy of the Surry Power Station electrical distribution system. The review consisted of:

1. Analytically determining the capacity and capability of the offsite power system and onsite distribution system to automatically start as well as operate all required loads within their required voltage ratings in the event of: (1) an anticipated transient, or (2) an accident (such as a LOCA) without manual shedding of any electric loads.
2. Determining if there are any events or conditions which could result in the simultaneous or consequential loss of both required circuits from the offsite network to the onsite electrical distribution system and thus violate the requirement of General Design Criterion 17.

The criteria used in the technical evaluation of the analysis included General Design Criterion 5 (Sharing of Structures, Systems, and Components), General Design Criterion 13 (Instrumentation and Control), and General Design Criterion 17 (Electric Power System) of Appendix A to 10 CFR 50, IEEE Standard 308-1974, ANSI C84.1-1977 and the NRC staff positions and guidelines provided in the August 8, 1979, letter.

In Reference 4 it was concluded that the Surry Units 1 and 2 offsite power system and the onsite distribution system are capable of providing acceptable voltages for worst-case station electric load and grid voltages. Analysis results are included in Reference 5. Continued assurance that acceptable voltages are available is maintained using calculation(s) which are periodically updated.

The voltage level and current loading of all station distribution buses are displayed in the control room. The status of the switchyard breakers and the source of reserve station power are readily available to the operator. Indicating lights show the source of power to each bus. Alternate sources may be manually selected by the operator, but prearranged automatic transfer takes place on failure of the normal source. The following instruments are provided in the control room to monitor emergency bus voltage performance:

1. Battery voltage indication.
2. Battery ground indication.
3. Emergency bus voltage.
4. Emergency bus frequency.
5. Emergency bus undervoltage alarm.
6. Low battery voltage alarm.
7. Emergency bus overvoltage alarm.
8. Hi battery voltage alarm.
9. Emergency bus open phase condition alarm.

Routine control of normal and standby electrical power is from the control room. However, essential loads can also be controlled from the emergency switchgear located below the control room. The emergency switchgear is designed so that local operation is possible with or without control power.

Control switches on the main control board are clearly identified by system. Emergency switchgear and control centers are identified as control devices for essential components.

The diesel-generator panel contains instruments and controls to serve the emergency bus. Provisions for synchronizing the diesel generator manually with the reserve station service power systems are also provided. The generators are manually synchronized with the system and loaded for periodic load tests.

The diesel generators and associated equipment are located in a Class I and tornado-protected structure. Each generator and its associated equipment will withstand, without loss of function, either the design-basis earthquake or the atmospheric pressure drop associated with the design tornado.

Emergency switchgear is located in the shielded control area below the control room. Status of the emergency power bus can be determined at the emergency switchgear. Emergency distribution air circuit breakers can be manually operated at the switchgear (Section 7.7).

Switchgear associated with the electrical feeds to the emergency buses are enclosed in metal housings and protected from the weather.

Essential electrical components and circuits are located and distributed within protected zones. All cables, conductors, motors, pumps, control stations, etc., are identified by a mark number or by function. The markings consist of painted stencils or marked tags applied or attached to each component.

Lines, valves and equipment subject to freezing or crystallization of boron are electrically heat traced and insulated. The heat source is automatically energized when the temperature drops below preset limits. Therefore, icing or crystallization could not interfere with the or injection of coolant during accident conditions.

8.5 REFERENCES

1. Letter from C. M. Stallings, Vepco, to H. R. Denton, NRC, Subject: *Surry Power Station Units 1 and 2 480-V Emergency Power System,* dated June 18, 1979.
2. Letter from B. R. Sylvia, Vepco, to H. R. Denton, NRC, Subject: *Surry Unit 2 480-V Emergency Bus,* dated May 22, 1980.
3. Generic Letter from the U. S. Nuclear Regulatory Commission, to all Licensees, Subject: *Adequacy of Station Electrical Distribution System Voltages,* dated August 8, 1979.

4. Letter from S. A. Varga, NRC, to R. H. Leasburg, Vepco, Subject: *Safety Evaluation Surry Power Station Units 1 and 2, Adequacy of Station Electric Distribution System Voltages,* dated October 6, 1982 (with enclosures).

5. Letter from R. H. Leasburg, Vepco, to H. R. Denton, NRC, Subject: *General Design Criteria 17 Analysis, Surry Unit Nos. 1 and 2,* dated March 31, 1982.

6. Letter from W. L. Stewart, Virginia Electric and Power Company, to NRC, Subject: *Transmittal of Final Survey Report, Emergency Diesel Generator Sequencing*, dated May 4, 1989.

Intentionally Blank

8.6 TESTS AND INSPECTIONS

All electrical equipment was specified for manufacture in strict accordance with the latest requirements of the National Electrical Manufacturers Association (NEMA), the Institute of Electrical and Electronic Engineers (IEEE), or the American National Standards Institute, Inc. (ANSI) standards, where applicable.

Electrical equipment was protected during shipment and was properly stored at the job site during construction.

The installation of all equipment was under the supervision of a qualified electrical construction engineer. Special attention was given to mechanical alignment and electrical ground connections. The dielectric of all insulation was measured and corrected if necessary before the equipment was energized.

The control power for operating major motor starters is supplied from the station batteries. These batteries are kept at a constant voltage, and they are monitored continuously for voltage variations or undesired ground connections.

Each major motor or other piece of electrical equipment is protected by overcurrent relays that will disconnect the device if fault current is present. The protective relays are set and calibrated by Vepco trained personnel.

The availability and proper action of standby equipment are checked periodically while the unit is in operation.

Testing of the automatic operation of the voltage transfer system at the 4160V level can be performed. Successful operation of the 4160V transfer scheme does not prevent a unit shutdown but is designed to provide station service power automatically when a main generator is out of service.

Each standby power system was installed and checked out several months before criticality. The initial installation was tested to verify the starting speed and loading ability before being accepted. After acceptance, the emergency power systems were operated on a routine test schedule. These routine operations for several months before criticality recognized the initial failure rate and were sufficient to achieve a proven and mature standby power system.

The diesel generators are essential parts of the engineered safeguards system. Starting, loading, and full-load operability of the diesel generators are tested in accordance with Technical Specifications. One method of conducting this test is to connect all operating safeguards equipment to an emergency bus that is not to be tested. The alternative emergency bus is then given a full operational test by opening its normal source breaker. The loss of voltage on the bus being tested automatically starts the emergency generator, closes the generator breaker, and re-energizes that emergency bus system. By placing the starters in either the operating or test position, individual components or systems may be checked completely or the test may be limited to the operation of the motor starters. During the testing of one emergency generator system, the alternative system is still available if required.

The Technical Specifications also include a refueling test requirement for simulating the loss of offsite power in conjunction with a safety injection actuating signal. To preclude a potential reactor coolant system pressurization transient, the breakers for the high-head and low-head safety injection pumps are placed in the test mode so that the pumps will not start. (The operability of these pumps is the subject of a separate monthly test.) This refueling test verifies diesel-generator starting and loading, as well as the starting of required loads.

During power operation, the station batteries and diesel-generator batteries are periodically checked in accordance with Technical Specifications to provide an indication of battery cells becoming unserviceable before they fail. An equalizing or overvoltage charge is applied to the batteries and is applied long enough to bring all cells up to an equal voltage. If these tests reveal a weak cell or a weakening trend in any cell, replacements are made as necessary. A disconnected battery or broken cell connector would be revealed during these equalizing charges. Periodically, the battery charger is disconnected and the ability of the battery to maintain voltage and assume the dc load is verified. This test will uncover any high-resistance connections or cell internal malfunctions.

During construction, checks and inspections were made to ensure that complete separation was maintained between vital equipment to ascertain redundant systems. The separation of the dc power supply system was verified before operation by performing functional checks on the two battery trains. Verification was provided by removing one battery train from service and operating the equipment on the other train. Checks were made to ascertain that the proper equipment was actuated. This procedure was followed for checking both dc battery trains.

Surry Power Station
Updated Final Safety Analysis Report

Chapter 9

Intentionally Blank

Chapter 9: Auxiliary and Emergency Systems
Table of Contents

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems
Table of Contents (continued)

Chapter 9: Auxiliary and Emergency Systems

List of Tables

Chapter 9: Auxiliary and Emergency Systems

List of Tables (continued)

Chapter 9: Auxiliary and Emergency Systems

List of Figures

CHAPTER 9 AUXILIARY AND EMERGENCY SYSTEMS

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

9.1 CHEMICAL AND VOLUME CONTROL SYSTEM

The chemical and volume control system is used to:

1. Adjust the concentration of the chemical neutron absorber for chemical reactivity control.
2. Maintain the proper water inventory in the reactor coolant system.
3. Provide the required seal-water flow for the reactor coolant pump shaft seals.
4. Provide high-pressure flow to the safety injection system.
5. Provide for reactor coolant cleanup and degasification.
6. Maintain the proper concentration of corrosion-inhibiting chemicals in the reactor coolant.
7. Provide a means for filling the reactor coolant system.
8. Provide a means for draining the reactor coolant system to the primary drain system by means of the excess letdown flow path.

The chemical and volume control system has provision for injecting the following chemicals into the reactor coolant system, as required:

1. Hydrogen
2. Lithium hydroxide
3. Hydrogen peroxide
4. Hydrazine
5. Zinc Acetate

9.1.1 Design Bases

During normal unit operation, the chemical and volume control system is designed to automatically provide boric acid solution at a preset concentration, which matches the reactor coolant system boron concentration, to compensate for minor leakage of reactor coolant.

The chemical and volume control system design also permits the addition of a preselected quantity of reactor primary-grade makeup water or concentrated boric acid solution at a preselected flow rate to the reactor coolant system.

The chemical and volume control system has the capacity to achieve cold shutdown of both units, each with one control rod assembly completely withdrawn following a refueling shutdown. One boric acid storage tank has sufficient capacity (if maintained above the low-level alarm point) to provide a cold shutdown for one unit with one control rod assembly completely withdrawn.

9.1.1.1 Redundancy of Reactivity Control

In addition to the reactivity control achieved by the control rod assemblies, as detailed in Section 7.3, reactivity control is provided by the chemical and volume control system, which regulates the concentration of boric acid solution in the reactor coolant system. Under postulated system malfunctions, the system is designed to prevent uncontrolled or inadvertent reactivity changes that might stress the system beyond design limits.

9.1.1.2 Reactivity Shutdown Capability

Normal reactivity shutdown capability is provided by control rod assemblies, with boric acid injection used to compensate for the xenon transient and for unit cooldown. Any time that the unit is at power, the quantity of boric acid retained in the boric acid storage tanks and ready for injection always exceeds that quantity required for a cold shutdown.

The boric acid solution is transferred from the boric acid storage tanks by boric acid transfer pumps to the suction of the charging pumps, which inject boric acid into the reactor coolant. Any charging pump and any boric acid transfer pump is capable of being operated from diesel-generator power on loss of primary power. Boric acid is injected by one charging and one boric acid transfer pump at the approximate reactivity insertion rate of -0.14% delta k/k per minute, which shuts the reactor down in 25 minutes with no rods inserted. In 25 additional minutes, enough boric acid can be injected to compensate for xenon decay, although xenon decay below the equilibrium operating level does not begin until approximately 20 hours after shutdown from full power. Additional boric acid is added if it is desired to bring the reactor to cold shutdown conditions.

On the basis of the above, the injection of boric acid provides backup shutdown reactivity capability, independent of control rod assemblies, which normally serve this function in the short-term situation. Shutdown for long-term and reduced-temperature conditions is accomplished with boric acid injection using redundant components.

The reactivity control systems provided are capable of making and holding the core subcritical for any cold shutdown, hot shutdown, or hot operating condition, including those resulting from power changes. The maximum excess reactivity expected for reload cores occurs at the beginning of life, no xenon conditions. A total of 48 control rod assemblies is provided. The assemblies are divided into two categories comprising four control banks and two shutdown banks.

The control banks, used in combination with soluble boron, provide control of the reactivity changes at power throughout the life of the core. The control banks are used to compensate for short-term reactivity changes at power that might be produced due to variations in reactor power requirements or in coolant temperature. The soluble boron control is used to compensate for the slower changes in reactivity throughout core life, such as those due to fuel depletion and fission product buildup and decay.

The reactor core, together with the reactor control system and the reactor protection system, is designed so that the minimum departure from nucleate boiling ratio (DNBR) will not be less than the design DNBR limit (Section 3.2.3) and there will be no fuel melting during normal operation, including anticipated transients.

Shutdown control rod assemblies are provided to supplement the control rod assembly control groups to make the reactor at least 1.77% delta k/k subcritical following trip from any credible operating condition to the hot shutdown condition. This assumes the highest-worth control rod assembly remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to ensure no DNB occurs for the most severe anticipated cooldown transient associated with a single active failure, i.e., accidental opening of a steam bypass valve or relief valve. This is achieved with a combination of control rod assemblies and automatic boron addition via the safety injection system with the highest-worth rod being fully withdrawn. Manually controlled boric acid addition is used to maintain the shutdown margin for the long-term conditions of xenon decay and reactor coolant system cooldown.

9.1.1.3 **Codes and Classifications**

The codes and classifications of chemical and volume control system components are stated in Table 9.1-1.

Both the regenerative and excess letdown heat exchangers are classified Class C according to the ASME Code, Section III. At the time of procurement, these heat exchangers met all of the requirements for Class C vessels. Westinghouse supplemented these minimum requirements with the following additional requirements:

1. Welded tube to tube sheet joints.
2. Gas leak test of tube to tubesheet welds in addition to full differential pressure hydrostatic tests.
3. Special tube to tubesheet weld procedure qualifications.
4. Ultrasonic or eddy current test of tubing.
5. Dye penetrant examination of tube to tubesheet welds and root pass as well as final pass to all other pressure containing welds.
6. Fatigue analysis as required by paragraph 415.1 of Section III to demonstrate that the unit can withstand the transients that it is expected to experience during its design life.

In addition, Westinghouse equipment specifications for the regenerative and excess letdown heat exchangers met the basic requirements of Appendix IX of the ASME Code, except that Westinghouse did not require nondestructive test personnel to be qualified to American Society for Nondestructive Testing procedures. Where the suppliers' personnel were not so qualified, Westinghouse assured that suppliers' personnel were adequately qualified by periodic observation of their performance, and Westinghouse also performed the customary final inspections. As noted above, Westinghouse quality assurance levels and quality control procedures were in excess of standard code requirements for Class C vessels.

The replacement tube bundle for the Unit 1 Excess Letdown Heat Exchanger (1-CH-E-4) was fabricated to ASME Section VIII, Div. 1, 1992 and A92 requirements. Code reconciliation concluded that the original requirements were met or exceeded, including the additional requirements previously specified. The fabrication and testing were witnessed by Virginia Power personnel and by an Authorized Nuclear Inspector, as applicable.

9.1.2 System Design and Operation

The chemical and volume control system is shown in Figure 9.1-1 and Reference Drawings 1 through 3. The system is provided with overpressure devices, such as safety valves, to protect components whose design pressure and temperature are less than the reactor coolant system design limits. System discharge from overpressure protective devices and other system leakages are directed to closed system.

System design enables post-operational hydrostatic testing to applicable code test pressures, with the relief valves gagged. After hydrostatic testing, the relief valves are set at the system design pressure.

The components in the chemical and volume control system that the two units share are the three boric acid storage tanks and the boric acid batch tank. These tanks are listed in Table 9.1-2.

9.1.2.1 **System Description**

During normal unit operation, reactor coolant flows through the letdown line from the reactor coolant pump discharge side of reactor coolant loop number 1 cold leg, and returns through the charging line to the reactor coolant pump discharge side of the cold leg of loop number 2. The charging line has a check valve located downstream of the charging line isolation valve. An excess letdown path from the reactor coolant system is provided in the event that the normal letdown path is nonfunctional. Reactor coolant can be discharged from each reactor coolant loop, or all loops concurrently, through the common loop drain header to the tube side of the excess letdown heat exchanger. Each of the connections to the reactor coolant system loops has an isolation valve located close to the loop piping.

Reactor coolant entering the chemical and volume control system flows through the shell side of the regenerative heat exchanger, where its temperature is reduced. The coolant then flows through the letdown orifices to reduce the coolant pressure. The letdown flow leaves the reactor containment and enters the auxiliary building, where it undergoes a second temperature reduction in the tube side of the nonregenerative heat exchanger, followed by a second pressure reduction by a low-pressure letdown valve. After passing through one of the mixed-bed demineralizers, where anionic and cationic impurities are removed, coolant flows through the reactor coolant filter and enters the volume control tank through a spray nozzle. Reactor coolant letdown flow is diverted to the boron recovery system (Section 9.2) on a high-level signal from the volume control tank.

The cation-bed demineralizer, located downstream of the mixed-bed demineralizer, is used intermittently to control cesium activity in the coolant and also to remove excess lithium, which is formed from B^{10}(n, a) Li^{7} reaction.

Hydrogen is automatically supplied, as determined by pressure control, to the vapor space in the volume control tank, which is predominantly hydrogen and water vapor. The hydrogen within this tank is, in turn, the supply source to the reactor coolant. Fission gases are periodically removed from the system by venting the volume control tank to the vent and drain system (Section 9.7) or by diverting the letdown stream to the primary drain tank and then to the gas stripper in the boron recovery system before a cold or refueling shutdown. The coolant flows from the volume control tank to the charging pumps, which raise the coolant pressure above that in the reactor coolant system. The coolant then enters the containment, passes through and is heated in the tube side of the regenerative heat exchanger, and then returns to the reactor coolant system.

A portion of the high-pressure charging flow is injected into the reactor coolant pumps between the pump impeller and the shaft seal so that the seals are not exposed to high-temperature reactor coolant.

From the injection flow of 8 gpm, 2.5 gpm passes through the pump radial bearing, shaft seal and then on to the chemical and volume control system, and 5.5 gpm passes through the thermal barrier heat exchanger and into the reactor coolant system, where it constitutes a portion of reactor coolant system water makeup. Shaft seal leakage flow is filtered, cooled in the seal-water heat exchanger, and returned to the suction of the charging pumps. Coolant injected through the reactor coolant pump labyrinth seals returns to the volume control tank by the normal letdown flow path through the regenerative heat exchanger. Indication of seal injection flow is provided locally and in the control room.

When the normal letdown flow route is not in service, labyrinth seal injection flow is returned to the suction of the charging pumps through the excess letdown and seal-water heat exchangers.

Boric acid is dissolved in heated water in the batching tank to a concentration of at least 7.0% (but not > 8.5%) by weight. The lower portion of the batching tank is jacketed to utilize low-pressure steam to permit heating of the batching tank solution. One of four boric acid transfer pumps is used to transfer this concentrated solution to the boric acid storage tanks. Small quantities of boric acid solution from the boric acid storage tanks are metered from the discharge of an operating boric acid transfer pump for blending with the water supplied to makeup for normal leakage losses, or for increasing the reactor coolant boron concentration during normal load follow operation. Electric immersion heaters maintain the solution in the boric acid storage tanks at an elevated temperature to prevent precipitation. The design temperature to ensure that the boric acid remains in solution at its highest concentrations is ≥112°F.

During unit start-up, normal operation, load reductions, and shutdowns, liquid effluents containing boric acid flow from the reactor coolant system through the letdown line and are collected in the boron recovery system (Section 9.2). Cover gases displaced during the filling of volume control tanks are vented to the gaseous waste disposal system (Section 11.2.5).

During the unit cooldown phase and when the unit is in cold shutdown, the residual heat removal loop is operated to control Reactor Coolant System (RCS) temperature. Because of the lower pressure in the reactor coolant system, insufficient pressure exists to maintain flow through the letdown orifices. A purification flow path is provided to remove fission and corrosion products, and other solid and liquid impurities. During the time that the RHR system is secured and the reactor coolant system is above 350°F the purification flow isolation valve, 1-RH-HCV-1142, is normally closed and is opened as required to fill the system from letdown.

A portion of the flow leaving the residual heat exchangers passes through the nonregenerative heat exchanger, mixed-bed demineralizers, reactor coolant filter, and volume control tank. The fluid then is pumped by the charging pump through the tube side of the regenerative heat exchanger into the reactor coolant system and, through the auxiliary spray line, into the pressurizer.

The letdown orifice isolation valves and the pressurizer auxiliary spray valves are equipped with quick-disconnect instrument air fittings to allow connection to a portable air source for local operation. The operation of the letdown orifice isolation valves provides an alternate letdown path during plant cooldown following a postulated fire in accordance with the requirements of Appendix R to 10 CFR 50. The analysis for Appendix R requires that the auxiliary spray valve be closed and disabled to ensure pressurizer pressure control. The auxiliary spray valve quick disconnect is not credited in the Appendix R analysis.

A beyond design basis (BDB) piping connection exists off of a 2” connection on the charging pump discharge header. This connection allows for the discharge hose of a portable pump to connect to this header. The hose is connected to the BDB piping via one of two different temporary adapter fittings. The adapter fitting that must be used is dependent on the current reactor operating condition. The purpose of this connection is to allow the portable pump to inject borated/makeup water into the RCS during a beyond design basis external event (BDBEE).

Two RCS injection standpipes are located in the Auxiliary Building. These standpipes can be used as hose extensions to facilitate the rapid deployment of the hoses for the BDB connection on this system. (Note: these standpipes are not physically connected to the Chemical and Volume Control (CH) System.)

Table 9.1-2 lists principle component data for the chemical and volume control system, Table 9.1-3 lists system performance requirements, and Table 9.1-4 gives data for reactor coolant fission product concentrations.

9.1.2.2 Reactor Coolant Activity Concentration, Monitoring, and Control

The parameters used in the calculation of the reactor coolant fission product inventory for the original plant design, including pertinent information concerning the coolant cleanup flow rate and the demineralizer effectiveness, are presented in Table 9.1-5. The results of the calculations are presented in Table 9.1-4. In these calculations, the defective fuel rods are assumed to be uniformly distributed throughout the core and the fission product escape rate coefficients are therefore based upon an average fuel temperature. Volume control tank noble gas concentrations with 1% failed fuel are shown in Table 9.1-6.

The fission product activity in the reactor coolant in the letdown stream of the regenerative heat exchanger during operation with small cladding defects in 1% of the fuel rods is computed using the following differential equations:

For parent nuclides in the coolant,

$$\frac{dN_{wi}}{dt} = DV_i N_{C_i} - \left(\lambda_i + R_{\eta_i} + \frac{B'}{B_O - tB'}\right) N_{wi}$$

For daughter nuclides in the coolant,

$$\frac{dN_{wj}}{dt} = DV_j N_{C_j} - \left(\lambda_i + R_{\eta_i} + \frac{B'}{B_O - tB'}\right) N_{wj} + \lambda_i N_{wi}$$

Where:

N = population of nuclide units

D = fraction of fuel rods having defective cladding

R = purification flow, coolant system volumes per sec

B_o = initial boron concentration, ppm

B' = boron concentration reduction rate by feed and bleed, ppm/sec

t = time, sec or fraction

η = removal efficiency of purification cycle for nuclide

λ = radioactive decay constant

v = escape rate coefficient for diffusion into coolant

Subscript C refers to “core”
Subscript w refers to “coolant”
Subscript i refers to “parent nuclide”
Subscript j refers to “daughter nuclide”

During unit operation, continuous monitoring of the reactor coolant is accomplished by means of high-range and low-range gross activity monitors. These monitors, which are described in Section 11.3.3, are capable of determining any sudden increase in activity level due to failed fuel within the range of 10^{-4} μCi/cc to 10^{3} μCi/cc.

The Technical Specification limit on reactor coolant activity provides adequate protection to the general public. The limits on reactor coolant system leakage and on effluent releases govern the potential release of coolant activity to the environment during normal reactor operation, and have been established on the basis of the limiting values of reactor coolant activity. The reference accident considered for the bases is the steam generator tube rupture (Section 14.3.1).

Rupture of a steam generator tube would allow a portion of the reactor coolant activity to enter the steam and feedwater systems outside the containment. In this event, the radioactive noncondensable gases would be detected by the radiation monitor located in the air ejector effluent line. When the radioactivity level reaches the alarm setpoint of the monitor, trip valves in the effluent line automatically actuate to divert the flow to the containment and to close the vent to atmosphere. Once safety injection is initiated, the air ejector exhaust is automatically isolated from containment. The ejector would then vent to the turbine building via vents in the ejector loop seals. The effluent can also be manually routed through the ventilation vent no. 2 at a location equipped with a high range radiation monitor. The radiological consequences of a steam generator tube rupture have been evaluated and determined to be acceptable as discussed in Section 14.3.1.

9.1.2.3 **Tritium Production**

9.1.2.3.1 Overall Tritium Sources

Within a pressurized light-water reactor, tritium is formed from several sources. The greatest potential source is the fissioning of uranium fuel, which yields tritium as a ternary fission product at a rate of approximately 8×10^{-5} atoms per fission, or 1.05×10^{-2} Ci/MWt/day. Boron-bearing burnable poison and secondary source rods are also a source of tritium. The amount of tritium appearing in the reactor coolant from these three sources is a function of the fuel, burnable poison, and secondary source cladding material permeability to tritium.

A direct source of tritium in the reactor coolant is the reaction of neutrons with dissolved boron used for reactivity control. The boron concentration is approximately 2000 ppm at the beginning of the fuel cycle, and is reduced to zero at the end of the fuel cycle. Neutron reactions with lithium are also a direct source of tritium. Lithium is present for pH control, and as a product of boron reactions with neutrons. The amount of lithium present, however, is carefully controlled to approximately 0.7-3.7 ppm by demineralization and/or chemical additions. A minute amount of tritium is also produced by neutron reactions with naturally occurring deuterium in light water.

9.1.2.3.2 Specific Tritium Sources

9.1.2.3.2.1 *Ternary Fissions - Clad Diffusion.* A program was undertaken by Westinghouse to determine the source of tritium in the reactor coolant in operating plants with both stainless steel and Zircaloy cladding. This program clearly indicated that, for the then-current generation of Westinghouse reactors with Zircaloy-clad fuel, 1% or less of the tritium produced in the fuel would diffuse through the cladding into the coolant.

The Ginna plant (nominal 1455 MWt) has Zircaloy cladding. At one point, after approximately 8 months of operation, the tritium concentrations were less than 0.3 μCi/cc in the reactor coolant. The monthly discharges from the plant averaged approximately 5 Ci/month. Experiences at the Beznau (Switzerland) and Jose Cabrera (Spain) plants were comparable. A program to follow the buildup of tritium at the Ginna plant indicated a potential source from the core which was 1% or less of the ternary fissions generated in the fuel.

Westinghouse has in the past assumed that 30% of the tritium from ternary fissions would diffuse through the Zircaloy-clad fuel. Such fuel was used as a basis for systems and operational design. Present experience indicates that this was conservative.

Like Zircaloy, ZIRLO and Optimized ZIRLO are made of approximately 98% zirconium. The properties of ZIRLO and Optimized ZIRLO cladding relative to tritium release are not expected to differ significantly from Zircaloy (References 2 and 4).

9.1.2.3.2.2 *Boron Reactions.* The neutron reactions with boron that result in the production of tritium are:

B^{10} (n, 2 α) T

B^{10} (n, α) Li^7 (n, n α) T

B^{11} (n, T) Be^9

B^{10} (n, d) Be^{9*} (n, α) Li^6 (n, α) T

Of the above reactions, only the first two contribute significantly to tritium production in a pressurized-water reactor. The B^{11} (n, T) Be^9 reaction has a threshold of 14 MeV and a cross section of 5 mb. Since the number of neutrons produced at this energy is less than 10^9 n/cm^2/sec, the tritium produced from this reaction is negligible. The B^{10} (n, d) reaction may be neglected, since Be^{9*} produced in this reaction has been found to be unstable.

9.1.2.3.2.3 *Lithium Reactions.* The neutron reactions with lithium resulting in the production of tritium are:

Li^7 (n, n α) T

Li^6 (n, α) T

In Westinghouse reactors, lithium is used for pH adjustment of the reactor coolant. The reactor coolant lithium concentration is maintained between 0.7 and 3.7 ppm lithium by the addition of Li^7OH and by the use of cation resin. This demineralizer will remove any excess of lithium such as could be produced in the B^{10} (n, α) Li^7 reaction.

The Li^6 (n, α) T reaction is controlled by limiting the Li^6 impurity in the Li^7OH used in the reactor coolant and by lithiating the demineralizers with 99.9 atom% Li^{7}.

9.1.2.3.2.4 *Control Rod Sources.* In a fixed burnable poison rod the two primary sources of tritium generation are the B^{10} (n, 2 α) T and the B^{10} (n, α) Li^7 (n, n α) T reactions. Unlike the coolant where the Li^7 level is controlled at 0.7-3.7 ppm, there is a buildup of Li^7 in the burnable poison rod. Tritium production in a burnable poison rod is approximately 72 Ci/lb B^{10} during its first cycle of exposure.

The control rod materials used are Ag-In-Cd, which are not tritium sources.

9.1.2.3.2.5 *Secondary Source Rods.* In a Secondary Source rod, the primary source of tritium generation is the irradiation of Beryllium. The neutron reactions that result in the production of tritium are:

Be^9 (n, α) He^6 (β) Li^6 (n, α) T

Be^9 (n, γ) Be^{10} (n) Li^8 + T

Be^9 (n) Li^7 + T

Li^7 (n, n α) T

Of the above reactions, the first reaction is the primary source of tritium production from the sources. The permeability of the secondary source pellets and cladding (stainless steel) to tritium is high. Secondary sources were not analyzed as potential sources of tritium in the reactor for the original plant design and are not included in Table 9.1-7. As stated in Section 9.1.2.3.2.1, conservative assumptions regarding the release of tritium from the fuel (30%) were made in the original analyses. The original analyses, with this assumption, account for potential tritium release from the source rods.

9.1.2.3.2.6 *Deuterium Reactions.* Since the amount of naturally occurring deuterium in water is less than 0.0015, the tritium produced from this reaction is negligible (less than 1 Ci per year).

9.1.2.3.2.7 *Total Tritium Sources.* Tritium sources in the reactor coolant systems of the Surry units are listed in Table 9.1-7. They are presented on the basis of the original plant design of 12 months of operation at 2546 MWt and a 0.8 load factor.

Two columns are presented in the tables; a previous design value and the presently expected tritium release value to the reactor coolant. The design values are based on a release of 30% of the tritium produced being diffused through the fuel cladding.

A tritium limit is established to meet the allowable concentration in the circulating water discharge. For one unit, the production rate of tritium due to ternary fission is calculated to be 7850 Ci/yr., and 30%, as a design basis, is assumed to be released to the coolant by recoil through the cladding. (See Table 9.1-7.) To this is added tritium from other sources, for a total of approximately 2745 Ci/yr. of total tritium activity added to the reactor coolant during the initial fuel cycle, and 2750 Ci/yr. during an equilibrium fuel cycle. Using the projected turnover rate of four reactor coolant system volumes per year or more, the tritium activity in the primary coolant should never increase beyond about 2.5 μCi/cc.

9.1.2.4 **Reactor Makeup Control**

Reactor makeup control consists of an instrument and control group arranged to provide a manually preselected makeup composition to the charging pump suction header or the volume control tank. The makeup control functions are designed to maintain desired operating fluid inventory in the volume control tank and to adjust reactor coolant boron concentration for chemical shim reactivity control.

Makeup for normal primary system leakage is regulated by reactor makeup control, which is set by the operator to blend water from the primary-water tanks with concentrated boric acid to match the reactor coolant boron concentration. Makeup is added automatically if the volume control tank level falls below a preset value.

Reactor makeup control is designed to operate from the control room by manually preselecting makeup composition to the charging pump suction header or the volume control tank. This maintains the desired operating fluid inventory in the volume control tank and adjusts the reactor coolant boron concentration for proper reactivity control. The operator can stop the makeup operation at any time in any operating mode by remotely closing the makeup stop valves, or by placing the makeup mode control switch to stop.

One primary-water supply pump and one boric acid transfer pump normally are operated. If either pump trips, an alarm alerts the operator to a deviation of flow rate from the control setpoint. The standby primary water makeup pump will start automatically due to low header pressure, or it may be started manually. The standby boric acid transfer pump is started manually.

Makeup water to the reactor coolant system is provided through the chemical and volume control system from the following sources:

1. The primary-water tanks, which provide water for primary coolant dilution when the reactor coolant boron concentration is to be reduced.
2. The boric acid storage tanks, which supply a concentrated boric acid solution when reactor coolant boron concentration is to be increased. Water chemistry for the boric acid storage tanks is shown in Table 9.1-8.
3. The refueling water storage tank, which supplies borated water for emergency makeup.

4. The chemical mixing tank, which is used to inject small quantities of solution when additions of a pH control chemical are necessary.

Seal-water inleakage to the reactor coolant system requires a continuous letdown of reactor coolant to maintain the desired inventory. In addition, bleed and feed of reactor coolant is required for removal of impurities and adjustment of boric acid in the reactor coolant.

9.1.2.4.1 Automatic Makeup Mode

The automatic makeup mode of operation of the reactor coolant water makeup control scheme provides boric acid solution at a preset concentration to match the boron concentration in the reactor coolant system. The automatic makeup compensates for minor leakage of reactor coolant without causing significant change in the boron concentration of the coolant.

Under normal unit operating conditions, makeup control is set for automatic operation. A preset low-level signal from the volume control tank level controller causes the automatic makeup control action to increase the speed on the normally running boric acid transfer pump, open the makeup stop valve to the charging pump suction, modulate closed the concentrated boric acid control valve, and modulate open the reactor primary-water makeup control valve. One primary-water supply pump is always in operation. The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the volume control tank to rise. At a preset high-level point, the makeup is stopped, the reactor primary-water makeup control valve closes, the boric acid transfer pump returns to low speed, the concentrated boric acid control valve opens, and the makeup stop valve to the charging pump suction closes.

9.1.2.4.2 Dilution Mode

The dilution mode of operation permits addition of a preselected quantity of reactor primary-grade water makeup at a preselected flow rate to the reactor coolant system. The operator selects the dilution mode, sets the reactor primary-water makeup flow controller setpoint to the desired flow rate, sets the reactor primary-water makeup batch integrator to the appropriate quantity if desired, and initiates system start. This opens the primary-grade water makeup control valve, which delivers primary-grade water to the volume control tank. Excessive rise of the volume control tank water level is prevented by automatic actuation of a three-way diversion valve, which routes the reactor coolant letdown flow to the boron recovery system. When the appropriate quantity of reactor primary-water makeup is added, the batch integrater causes the reactor primary-water makeup control valve to close, or the operator stops the makeup by placing the makeup mode control switch to stop.

9.1.2.4.3 Boration Mode

The boration mode of operation permits the addition of a preselected quantity of concentrated boric acid solution at a preselected flow rate to the reactor coolant system. The operator selects the boration mode, sets the concentrated boric acid flow controller setpoint to the desired flow rate, sets the concentrated boric acid batch integrater to the appropriate quantity if desired, and initiates system start. This opens the makeup stop valve to the charging pumps suction and the boric acid control valve. It also increases the speed on the normally operating boric acid transfer pump, which delivers a boric acid solution of at least 7.0% (but not 8.5%) by weight to the charging pump suction header.

When the appropriate quantity of concentrated boric acid solution is added, the batch integrator causes the boric acid transfer pump to return to low speed and closes the makeup stop valve to the suction of the charging pumps. The operation may be terminated manually at any time by actuating the makeup stop valve, or placing the makeup mode control switch to stop.

The operator usually initiates the boration mode of operation. There is no automatic actuation of the system except in the case of a volume control tank low-low-level signal. In this event, the charging pump suction is aligned to the refueling water storage tank, which contains boron nominally at 2400 ppm.

The maximum rate of boration of the primary system with the 60-gpm discharge of a boric acid transfer pump directed to the charging pump suction is 14.1 ppm/minute assuming 7.0 weight percent boric acid in the tanks. This provides compensation for a cooldown rate of approximately 4.9°F/min at the end of core life when the moderator temperature coefficient is most negative.

The maximum rate of boration corresponding to charging and letdown at the maximum design letdown flow rate of 120 gpm and assuming suction from the refueling water storage tank at the nominal (mid-point of range) concentration of 2400 ppm, is 5.5 ppm/min. At the end of cycle, this boration rate is adequate to compensate for a cooldown rate of 1.9°F/min.

9.1.2.4.4 Alarm Functions

Reactor makeup control is provided with alarm functions to call the operator’s attention to the following conditions:

1. Deviation of reactor primary-water makeup flow rate from the control setpoint.
2. Deviation of concentrated boric acid flow rate from the control setpoint.
3. High-level and low-level in the volume control tank. The high-level alarm indicates that the level in the tank is approaching a high level resulting in 100% diversion of the letdown stream to the boron recovery system. The low-level alarm indicates that the level in the volume control tank is approaching a low-low or emergency level in a case where the primary makeup control selector is not set for the automatic makeup mode and the volume control tank level drops below the makeup initiation point.
4. Low-low level in the volume control tank.

9.1.2.5 **Charging Flow Control**

Three single-speed horizontal centrifugal charging pumps are used to supply charging flow to the reactor coolant system and to perform the safety injection function, as discussed in Sections 6.1 and 6.2. The charging mode and the safety injection mode represent separate operating ranges on the pump head curves.

A flow transmitter on the charging line upstream of the regenerative heat exchanger transmits a signal to an indicator-controller in the control room. The controller regulates a throttling valve in the charging line to maintain a preset charging flow. A reactor coolant system pressurizer water level error signal resets the charging flow setpoint to provide corrective action. If the pressurizer level increases, the error signal changes the charging flow setpoint to a lower value which causes the control valve to move towards the closed position. The controller is provided with adjustable maximum and minimum flow limits. Maximum flow is limited to prevent entry into the safety injection mode and start-up of the standby charging pump during normal unit transient conditions. Minimum flow is limited to prevent flashing downstream from the letdown orifices.

Flow verification is provided by charging flow indication or, when the system is aligned to the fill header, by fill header flow indication. Separate power sources supply each indication. This increases the system reliability so that if a loss of a vital bus occurs, the operator could verify a flow of water entering the cooling system by re-aligning flow through the unaffected flow path.

A pressure switch in the charging pump discharge header actuates an alarm and starts a standby charging pump if the discharge header pressure falls to a preset low level.

The safety injection signal overrides any other associated control signal.

9.1.2.6 **Components**

A summary of principal component data is given in Table 9.1-2.

9.1.2.6.1 Regenerative Heat Exchanger

The regenerative heat exchanger is designed to recover the heat from the letdown stream by reheating the charging stream during normal operation. This exchanger also limits the temperature rise that occurs at the letdown orifices during transient periods when letdown flow exceeds charging flow.

The letdown stream flows through the shell of the regenerative heat exchanger, and the charging stream flows through the tubes. The exchanger is fabricated of austenitic stainless steel, and is of all-welded construction. The regenerative heat exchanger is capable of withstanding the thermal and pressure stresses resulting from the expected transients in working fluid temperature and pressure.

9.1.2.6.2 Letdown Orifices

Parallel letdown orifices are used to control the flow of the letdown stream during normal operation and reduce the coolant pressure to a value compatible with the nonregenerative heat exchanger design. Two orifices are used to attain maximum purification flow at normal reactor coolant system operating pressure, and the third orifice serves as a spare.

The orifices are placed in service by remote manual operation of their respective isolation valves. The standby orifice is used in parallel with the normally operating orifices in order to increase letdown flow when the reactor coolant system pressure is below normal. This arrangement provides standby capacity for control of letdown flow. Each orifice is constructed of austenitic pipe containing a corrosion-resistant and erosion-resistant insert bored to the diameter required.

9.1.2.6.3 Nonregenerative Heat Exchanger

The nonregenerative heat exchanger cools the letdown stream to the operating temperature of the mixed-bed demineralizers. Reactor coolant flows through the tube side of the exchanger while component cooling water flows through the shell. The letdown stream outlet temperature is automatically controlled by a temperature control valve in the component cooling water outlet stream. The unit is a multiple-pass-tube heat exchanger. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel.

9.1.2.6.4 Mixed-Bed Demineralizers

Two flushable mixed-bed demineralizers maintain reactor coolant purity by the use of a Li^7 cation resin and a hydroxyl-form anion resin. These resins remove fission and corrosion products and, in addition, the borated reactor coolant converts the anion resin to the borate form. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream (except for cesium, tritium, and molybdenum) by a minimum factor of 10.

Each demineralizer is sized to accommodate the maximum letdown flow. One demineralizer serves as a standby unit for use when the operating demineralizer becomes exhausted during operation.

The demineralizer vessels are fabricated of austenitic stainless steel and are provided with suitable connections to facilitate resin replacement. The vessels are equipped with a resin retention screen. Each demineralizer has sufficient capacity to operate for one core cycle with 1% defective fuel rods.

9.1.2.6.5 Deborating Demineralizers

When required, two anion demineralizers remove boric acid from the reactor coolant system fluid. The demineralizers are intended for use near the end of a core cycle when boron concentrations are low, but can be used at any time if required. Hydroxyl-based ion-exchange resin is used to reduce reactor coolant system boron concentration by releasing a hydroxyl ion when a borate ion is adsorbed.

When the resin is saturated, it is flushed to the spent-resin storage tank and new resin is added.

Each demineralizer is sized to remove that quantity of boric acid from the reactor coolant system necessary to maintain full-power operation near the end of core life without the use of the boron recovery system.

If desired, one of the two anion demineralizer vessels can be loaded with cation resin and used as a cation demineralizer to support control of Cesium and Lithium.

9.1.2.6.6 Cation-Bed Demineralizer

A demineralizer using a flushable cation resin bed in the hydrogen form is located downstream from the mixed-bed demineralizers and is used when required to control the concentration of Li^7 that builds up in the coolant from the B^{10} (n, α) Li^7 reaction. The demineralizer also has sufficient capacity to maintain the cesium-137 concentration in the coolant below 1.0 μCi/cc with 1% defective fuel. The demineralizer is used to control cesium as necessary during operation. The demineralizer vessel is fabricated of austenitic stainless steel and is provided with suitable connections to facilitate resin replacement when required. The vessel is equipped with a resin retention screen.

9.1.2.6.7 Reactor Coolant Filter

The filter collects resin fines and particulates using a filter element with a particle retention of 25 μm or less if such fines should carry over into the letdown stream. The vessel is fabricated of austenitic stainless steel, and is provided with connections for draining and venting. Design flow capacity of the filter is equal to the maximum purification flow rate.

Disposable synthetic filter elements are used. The reactor coolant filter is considered for replacement when there is a high-pressure differential across the filter or when a portable radiation monitor exceeds a dose rate limit.

9.1.2.6.8 Volume Control Tank

The volume control tank is the collecting point in the system for letdown flow, makeup, and chemical additions. It has surge capacity to compensate for changes in reactor coolant volume resulting from power level increases and the deadband in the reactor control temperature instrumentation.

A hydrogen gas overpressure is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant between 5 and 50 cm^3/kg of water at standard temperature and pressure. A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides liquid-to-gas contact between the incoming liquid and the hydrogen atmosphere in the tank.

A remotely operated vent valve discharging to the vent and drain system permits removal of gaseous fission products, when desired, which are stripped from the reactor coolant at this location. The volume control tank also acts as a head tank for the charging pump suction header. The tank is constructed of austenitic stainless steel.

9.1.2.6.9 Charging Pumps

Three charging pumps inject coolant into the reactor coolant system. These pumps also perform the safety injection function as discussed in Sections 6.1 and 6.2. The pumps are of the single-speed horizontal centrifugal type, and all parts in contact with the reactor coolant are constructed of austenitic stainless steel or other material of adequate corrosion resistance. These pumps have a mechanical seal and auxiliary gland bushing. This arrangement minimizes the possibility of reactor coolant leakage to the outside atmosphere. Pump leakage is collected in a catch container with overflow routed to the auxiliary building sump for disposal. The pump design prevents lubricating oil from contaminating the charging flow.

Each pump is designed to provide the full charging flow and the reactor coolant pump seal-water supply during normal seal leakage. Each pump is designed to provide rated flow against a pressure equal to the sum of the reactor coolant system safety valve pressure and the piping, valve, and equipment pressure losses at the design charging flows. The capacity of each charging pump permits operation at normal charging line flow with one reactor coolant pump shaft seal operating normally while the other two reactor coolant pumps are operating with significant seal flow. The capacity of each pump includes margin for recirculation flow. The recirculation flow is sufficient to protect the pumps when pump discharge valves are closed during testing or when pump discharge flow is low at minimum charging conditions.

9.1.2.6.10 Chemical Mixing Tank

The primary use of the chemical mixing tank is for the preparation of solutions for pH control and oxygen scavenging; it has a capacity more than sufficient to prepare a solution of pH control chemical for the reactor coolant system. It is fabricated of austenitic stainless steel. The capacity of the chemical mixing tank is determined by the quantity of 35% hydrazine solution necessary to increase the concentration in the reactor coolant by 10 ppm. The chemical mixing tank may also be used to add hydrogen peroxide to the reactor coolant. This occurs during refueling outages and is used to solubilize crud for controlled removal.

9.1.2.6.11 Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown if the normal letdown path is blocked. It is designed to cool a letdown flow equal to the nominal injection rate through three reactor coolant pump labyrinth seals. The unit is designed to reduce the letdown stream temperature from the cold-leg temperature to 195°F. The letdown stream flows through the tube side, and component cooling water circulates through the shell side. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel. All tube joints are welded. The unit is designed to withstand 12,000 step changes in the tube fluid temperature from 80°F to the cold-leg temperature.

9.1.2.6.12 Seal-Water Heat Exchanger

The seal-water heat exchanger removes heat from three sources: reactor coolant pump seal-water, reactor coolant discharged from the excess letdown heat exchanger, and charging pump recirculation flow. Reactor coolant flows through the tubes, and component cooling water is circulated through the shell side. The tubes are welded to the tubesheet because undesirable leakage could occur in either direction. All surfaces in contact with reactor coolant are austenitic stainless steel, and the shell is carbon steel.

The exchanger is designed to cool the excess letdown flow and the sealwater flow to the temperature normally maintained in the volume control tank if all the reactor coolant pump seals are leaking at the maximum design leakage rate.

9.1.2.6.13 Seal-Water Filter

The filter collects particulates using a filter element with a particle retention of 25 μm or less from the reactor coolant pump seal-water return from the excess letdown heat exchanger flow. The filter is designed to pass the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump seals. The vessel is constructed of austenitic stainless steel and is provided with connections for draining and venting. Disposable synthetic filter elements are used.

9.1.2.6.14 Boric Acid Filter

The boric acid filter collects particulates using a filter element with a particle retention of 25 μm or less from the boric acid solution being pumped to the charging pump suction line or boric acid blender. The filter is designed to pass the design flow of two boric acid pumps operating simultaneously. The vessel is constructed of austenitic stainless steel, and the filter elements are disposable synthetic cartridges. Provisions are available for venting and draining the filter.

9.1.2.6.15 Boric Acid Storage Tanks

Boric acid solution mixed in the batching tank is stored in three electrically heated boric acid storage tanks shared by both units. One tank is normally aligned for each unit and supplies boric acid for reactor coolant makeup. Makeup to the boric acid storage tanks is typically done by a batching process applied to the third tank which is not assigned to either unit. As needed, the aligned tanks may be filled from the third “unaligned” tank in order to maintain an adequate boric acid supply to each unit. The three tanks combined have sufficient boric acid capacity to provide cold shutdown for the two units, each with one control rod assembly completely withdrawn, following a refueling shutdown on both units. Each tank, if maintained above the low-level alarm point, can supply sufficient boration to provide cold shutdown for one unit with a control rod assembly completely withdrawn.

During reactor operation, it is necessary to recirculate the boric acid solution in the boric acid storage tanks and the associated piping in order to prevent localized precipitation of boric acid. Sampling frequency and water chemistry requirements to preclude precipitation are found in Table 9.1-8.

The concentration of boric acid solution in storage is at least 7.0% (but not > 8.5%) by weight. Periodic manual sampling and corrective action, if necessary, ensure that these limits are maintained. As a consequence, measured amounts of boric acid solution can be delivered to the reactor coolant to control the boron concentration. Each boric acid storage tank has an overflow with a water loop seal that is connected to the high level liquid waste tanks. The boric acid storage tanks are constructed of austenitic stainless steel.

9.1.2.6.16 Batching Tank

The batching tank is sized to hold one week's makeup supply of boric acid solution for transfer to the boric acid storage tanks. The basis for makeup is reactor coolant leakage of 0.5 gpm at beginning of core life. A local sampling point is provided for verifying the solution concentration prior to transferring it to the boric acid storage tank or for draining the tank. A tank manway is provided with a removable screen to prevent entry of foreign particles. In addition, the tank is provided with an agitator to improve mixing during batching operations. The tank is constructed of austenitic stainless steel and is not used to handle radioactive substances. The tank is provided with a steam jacket for heating the boric acid solution to ≥128°F.

9.1.2.6.17 Boric Acid Storage Tank Heaters

Two 100%-capacity electric immersion heaters in each boric acid storage tank are designed to maintain the temperature of the boric acid solution at ≥128°F with an ambient air temperature of 40°F, thus ensuring a temperature in excess of the solubility limit (108°F for a 14,858-ppm boron solution). The heaters are sheathed in incoloy.

9.1.2.6.18 Boric Acid Transfer Pumps

Four centrifugal two-speed pumps are used to circulate or transfer the boric acid solution. The pumps circulate the boric acid solution and inject boric acid into the charging pump suction header or furnish boric acid to the boric acid blender. Although one pump normally is used for boric acid batching and transfer for each unit and one for boric acid injection for each unit, either pump may function as standby for the other. The design head of one pump is sufficient, considering line and valve losses, to deliver rated flow to the charging pump suction header when volume control tank pressure is at the maximum operating value. All parts in contact with the solutions are austenitic stainless steel or other suitable corrosion-resistant material.

The boric acid transfer pumps are operated either automatically or manually from the control room. A main control room annuciator alarms when the system is in the nonautomatic control mode. Reactor makeup control operates one of the pumps automatically when the boric acid solution is required for makeup or boration.

9.1.2.6.19 Boric Acid Blender

The boric acid blender promotes thorough mixing of the concentrated boric acid solution and primary-grade water for the reactor coolant makeup circuit.

The blender consists of a conventional pipe fitted with a perforated tube insert. All material is austenitic stainless steel. The blender decreases the pipe length required to homogenize the mixture.

9.1.2.6.20 Electrical Heat Tracing

Electrical heat tracing is installed under the insulation on all pumps, piping, valves, line-mounted instrumentation, and components normally containing a concentrated boric acid solution. The heat tracing is designed to prevent boric acid precipitation due to cooling, by compensating for heat loss.

Exceptions are:

1. Lines that may transport concentrated boric acid but are subsequently flushed with reactor coolant or other liquid of low boric acid concentration during normal operation.
2. The boric acid storage tanks, which are provided with immersion heaters.
3. The batching tank, which is provided with a steam jacket.

Heat tracing tapes are resistant to mechanical, chemical, and heat damage, and are covered by protective and heat-retaining insulation. Duplicate tracing on sections of the chemical and volume control system normally containing boric acid solution provides backup if the operating tracing malfunctions. Monitoring electrical equipment allows functional testing of the heat tracing. The existence of a condition requiring redundant tracing to be operated will be indicated by an alarm in the control room. Circuit test results are documented in appropriate test procedures.

9.1.2.6.21 Valves

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges directly, or via a floor drain, to the vent and drain system. All other valves have stem leakage control. Globe valves are installed with flow over the seat when such an arrangement reduces the possibility of leakage. An exception to this preference includes the charging pump recirculation MOVs which are installed in a configuration that will expose the valve packing to the inlet pressure when the valve is closed. Basic material of construction is stainless steel for all valves except the batching tank steam jacket valves, which are carbon steel.

Isolation valves are provided at all connections to the reactor coolant system. Connections to the reactor coolant system that pass through the containment are equipped with isolation devices, as described in Section 5.2.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Pressure relief for the tube side of the regenerative heat exchanger is provided by a spring-loaded check valve around the charging line isolation valve. The valve relieves to the reactor coolant system.

All relief valves used in systems handling radioactive fluids are of the closed bonnet design and are constructed of stainless steel.

9.1.2.6.22 Piping

All chemical and volume control system piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing. Piping, valves, equipment, and linemounted instrumentation, which normally contain concentrated boric acid solution, are heated by electrical tracing to ensure solubility of the boric acid.

Portions of the stainless steel piping systems may contain stagnant oxygenated borated water during plant operations. Stagnant borated water in these portions may exist for periods of time longer than one week. Piping integrity is verified by periodic inservice inspection.

9.1.2.6.23 Zinc Injection System

Zinc is injected into the RCS for dose reduction and/or mitigation of Primary Water Stress Corrosion Cracking. The zinc injection system includes an injection skid which provides a small, continuous flow into the CVCS system. The skid is comprised of a common zinc solution tank and two separate pumping trains to ensure uninterrupted flow to the CVCS. Each train consists of a 5 ml/min max. positive displacement pump, pressure gauge and appropriate valves. Either pump can draw from the tank. The system injects into the Letdown Radiation Monitor line before it empties into the Volume Control Tank.

9.1.3 System Design Evaluation

9.1.3.1 **Availability and Reliability**

A high degree of functional reliability is ensured in the chemical and volume control system by providing standby components where performance is vital to safety and by ensuring safe response to the most probable mode of failure. Special provisions include duplicate heat tracing with alarm protection of lines, valves, and components normally containing concentrated boric acid.

The chemical and volume control system has three high-pressure charging pumps, each capable of supplying the required reactor coolant pump seal and makeup flow. The two units' charging systems are cross-connected to allow the use of the opposite unit's charging pumps to bring the disabled unit to cold shutdown during certain emergency conditions. Operation of the safety related manual cross-connect isolation valves is procedurally controlled. Reactor coolant pump seal injection is isolated on the fire affected unit prior to aligning the cross-connect during certain fire scenarios.

The electrical equipment of the chemical and volume control system for each unit is arranged so that redundant items are powered from two separate independent emergency electrical distribution systems consisting of 4160V and 480V buses (Figure 8.3-1). One charging pump and one boric acid transfer pump are powered from each train of the emergency electrical distribution system. A third charging pump is available which can be powered from either 4160V emergency bus. In case of loss of normal ac power, the emergency buses are automatically powered from the standby emergency diesel generators.

9.1.3.2 **Control of Tritium**

An analysis of the production of tritium in the reactor coolant is presented in Table 9.1-7. Even if all the tritium produced in the reactor coolant is discharged from the plant, the concentration of tritium in the discharge canal would be 4.8×10^{-6} Ci/cm^3 or less than 0.2% of that allowed by 10 CFR 20. This analysis was based in part on 30% of the fission-produced tritium diffusing through the clad. The expected diffusion with zirconium clad is less than 1%.

During normal operation, tritium will be present in the following systems:

1. Reactor coolant system.
2. Chemical and volume control system.
3. Sampling system.
4. Vent and drain system.
5. Liquid waste system.
6. Refueling water storage system.

The distribution of tritium among these systems will be dependent on the operating parameters of the plant.

Essentially all of the tritium is in chemical combination with oxygen as a form of water. Therefore, any leakage of coolant to the containment atmosphere carries tritium in the same proportion as it exists in the coolant. Thus, the level of tritium in the containment atmosphere, when it is sealed from outside air ventilation, is mainly a function of tritium level in the reactor coolant. In addition, it depends on the cooling water temperature at the ventilation cooling coils, and the presence of leakage other than reactor coolant as a source of moisture in the containment air.

All effluents discharged from the liquid waste system will be sampled and analyzed before release. Tritium releases to the environment resulting from primary system leakage will be accounted for by analysis of the containment atmosphere prior to containment purging and by periodic analysis of the steam generator blowdown.

There are two major considerations with regard to the presence of tritium in the reactor coolant, neither of which is limiting in the operation of the Surry units:

1. Possible station personnel hazard during access to the containment, since leakage of reactor coolant during operation causes an accumulation of tritium in the containment atmosphere.

2. Release of tritium to the environment.

9.1.3.3 Leakage Provisions

All chemical and volume control system valves and piping for radioactive services are designed to permit essentially zero leakage. The components designated for radioactive service are provided with welded connections to prevent leakage. However, flanged connections are provided on each charging pump suction and discharge, on each boric acid pump suction and discharge, on the relief valve inlets and outlets, on three-way valves, and on the flow meters to permit removal for maintenance.

The centrifugal charging pumps are provided with leakoffs which direct leakage to the auxiliary building sump. All valves that are larger than 2-inch and that are designated for radioactive service at an operating fluid temperature above 212°F are provided with a stuffing box and lantern leakoff connections. All control valves are provided with stuffing box and leakoff connections or are totally enclosed, and leakage is essentially zero for these valves.

Diaphragm valves are provided where the operating pressure is 200 psig or below and operating temperature is 200°F or below. Leakage is essentially zero for these valves.

9.1.3.4 Incident Control

The letdown line and the reactor coolant pump seal-water return lines penetrate the reactor containment. The letdown line contains air-operated valves inside the reactor containment and one air-operated valve outside the reactor containment, which is automatically closed by the containment isolation signal.

The reactor coolant pump seal-water return lines contain one motor-operated isolation valve outside the reactor containment, which is automatically closed by the containment isolation signal.

The seal-water injection lines to the reactor coolant pumps and the charging line are inflow lines penetrating the reactor containment. Each line contains two check valves in series inside the reactor containment to provide isolation of the reactor containment should a break occur in these lines outside the reactor containment.

9.1.3.5 **Malfunction Analysis**

9.1.3.5.1 Malfunction During a Loss-of-Coolant Accident

To evaluate system safety, failures or malfunctions are assumed concurrent with a loss-of-coolant accident (LOCA), and the consequences are analyzed. Proper consideration is given to station safety in the design of the system. Results of this analysis are presented in Table 9.1-9.

If a rupture takes place between a reactor coolant loop and the first isolation valve or check valve, a loss of reactor coolant occurs. The first isolation or check valve is always located as close as possible to the reactor coolant loop pipe. The analysis of a LOCA is discussed in Chapter 14.

If a rupture occurs in the chemical and volume control system outside the containment, or at any point beyond the first check valve or remotely operated isolation valve, actuation of the valve limits the release of coolant and ensures continued functioning of the normal means of heat dissipation from the core. For the general case of a rupture outside the containment, the largest source of radioactive fluid subject to release is the volume control tank. The consequences of such a release are discussed in Chapter 14.

9.1.3.5.2 Boration/Dilution Performance

When the reactor is subcritical during Refueling Shutdown, Cold Shutdown, Intermediate Shutdown, and Hot Shutdown, any change in core reactivity is continuously monitored by boron tri-fluoride proportional counters (i.e., SRNI) and indicated in the Main Control Room by visual and audible count rate indicators. In addition, RCS letdown divert valve position, VCT level, PG tank levels and PG header flow rate all provide indication in the Main Control Room of a potential mismatch between charging and letdown and unexpected usage of PG water. A high dilution flow rate event during shutdown operation is precluded by the Technical Specification requirement to close the main primary grade makeup flow path during all shutdown modes.

The boron dilution in shutdown operating conditions is discussed in Section 14.2.5.3. Dilution malfunctions during Power Operation or Reactor Critical are analyzed and the consequences discussed in Section 14.2.5.4.

At least two separate and independent flow paths are available for normal reactor coolant boration, i.e., the charging line or the reactor coolant pump seal labyrinths. The malfunction or failure of either flow path does not result in the inability to borate the reactor coolant system. An alternate flow path is always available for emergency boration of the reactor coolant. As backup to the boration system, the operator can also align the refueling water storage tank outlet to the suction of the charging pumps, if required.

A single malfunction in one of the boron makeup subsystems does not preclude the ability to maintain proper boron concentration in both units simultaneously.

Subsequent to complete loss of seal injection water to the reactor coolant pump seals, low charging pressure in the system header (below a preset value) automatically starts a standby charging pump. Even if the seal-water injection flow is not reestablished, the unit can operate if component cooling water is available, since the thermal barrier cooler cools the reactor coolant flow that passes through the thermal barrier cooler and seal leakoff from the pump volute. How long the unit can operate is determined by monitoring the reactor coolant pump bearing and seal temperatures, to ensure they remain within operating limits (Reference 3).

To ensure an alternate shutdown capability independent of cables, system, or components in the area, a remote monitoring panel which will monitor vital primary parameters and a cross connect between the two units' charging pump discharge lines has been incorporated. Operation of the cross connect is strictly manual. The cross connect is located in the auxiliary building.

9.1.3.5.3 Loss of Boric Acid Tank Concurrent With Loss of Offsite Power

The Surry reactors would not normally be brought to a cold shutdown condition without offsite power, but would remain in the hot standby condition. However, if it became necessary to bring the reactor to a cold shutdown condition in the event of a loss of offsite power, natural circulation and other emergency equipment could be used to do so.

In the event of a complete loss of offsite power and turbine trip, there would be a loss of power to the station auxiliaries, i.e., the reactor coolant pumps, main feedwater pumps, etc. The emergency diesel generators would start automatically to supply plant vital loads. Vital instruments are supplied by buses obtaining power from inverters, which in turn obtain power from the emergency batteries.

The auxiliary feedwater system would start automatically. It consists of two motor-driven auxiliary feedwater pumps that obtain power from the emergency diesels, and one steam-driven auxiliary feedwater pump that utilizes steam from the secondary system and exhausts to the atmosphere. Equipment required to inject boron into the reactor coolant system (the charging pump, and boric acid transfer pump) is supplied by the diesel generator. Feedwater required for cooldown is supplied by the auxiliary feedwater system. Steam would be released to atmosphere via the steam generator atmospheric relief valves, thereby dissipating the reactor heat energy. The air compressor required to ensure the functionality of the atmospheric relief valves is supplied by the diesel generators. Natural circulation could be used to circulate the coolant through the system to effect cooldown, as has been demonstrated by tests on reactors of similar design.

One tank, if maintained above the low-level alarm, can supply sufficient boric acid to provide cold shutdown for one unit with a control rod assembly completely withdrawn (Section 9.1.2.6.15). Similarly, the quantity of boric acid would be sufficient for the condition postulated, where the reactor is to be shut down after power operation shortly after refueling.

9.1.3.6 **Galvanic Corrosion**

The only types of materials that are in contact with each other in borated water are stainless steels, Inconel, and Stellite or other corrosion and wear resistant valve materials, and zirconium alloy (e.g., Zircaloy, ZIRLO, or Optimized ZIRLO) fuel element cladding. These materials have been shown to exhibit only an insignificant degree of galvanic corrosion when coupled to each other.

For example, the galvanic corrosion of Inconel versus 304 stainless steel resulting from high-temperature tests (575°F) in lithiated, boric acid solution was found to be less than -20.9 mg/dm^2 for the test period of 9 days. Further galvanic corrosion would be trivial, since the cell currents at the conclusion of the tests were approaching polarization. Zircaloy versus stainless steel Type 304 was shown to polarize at 180°F with lithiated, boric acid solution in less than 8 days, with a total galvanic attack of -3.0 mg/dm^2. Stellite versus stainless steel Type 304 was polarized in 7 days at 575°F in lithiated boric acid solution, with a total galvanic corrosion of -0.97 mg/dm^2 (Reference 1).

These tests show that the effects of galvanic corrosion are insignificant in systems containing borated water.

9.1.4 Minimum Operating Conditions

The minimum operating conditions for the chemical and volume control system are contained in the Technical Specifications.

9.1.5 Tests and Inspections

Periodic testing, calibration, and inspection are conducted on the various instrument channels to ensure proper instrument response and operation of alarm functions. The minimum frequencies for testing, calibrating, and inspection are contained in the Technical Specifications.

Most components are in use regularly during power operation; therefore, assurance of the availability and performance of the system and equipment is provided.

9.1 REFERENCES

1. D. G. Sammarone, *The Galvanic Behavior of Materials in Reactor Coolants*, WCAP 1844, 1961.
2. S. L. Davidson and T. L. Ryan, *VANTAGE+ Fuel Assembly Reference Core Report*, WCAP-12610-P-A (Proprietary), April 1995.
3. Westinghouse Electric Company, *NSAL 99-005: Reactor Coolant Pump Operation During a Loss of Seal Injection*, June 1, 1999.
4. H. H. Shah and P. Schueren, *Optimized ZIRLO™,* WCAP-12610-P-A and CENPD-404-P-A, Addendum 1-A, July 2006.

9.1 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-088A	Flow/Valve Operating Numbers Diagram: Chemical and Volume Control System, Unit 1
	11548-FM-088A	Flow/Valve Operating Numbers Diagram: Chemical and Volume Control System, Unit 2
2.	11448-FM-088B	Flow/Valve Operating Numbers Diagram: Chemical and Volume Control System, Unit 1
	11548-FM-088B	Flow/Valve Operating Numbers Diagram: Chemical and Volume Control System, Unit 2
3.	11448-FM-088C	Flow/Valve Operating Numbers Diagram: Chemical and Volume Control System, Unit 1
	11548-FM-088C	Flow/Valve Operating Numbers Diagram: Chemical and Volume Control System, Unit 2

Table 9.1-1
CHEMICAL AND VOLUME CONTROL SYSTEM CODE REQUIREMENTS

Regenerative heat exchanger	ASME III[a], Class C
Nonregenerative heat exchanger	ASME III, Class C, Tube Side; ASME VIII, Shell Side
Mixed-bed demineralizers	ASME III, Class C
Reactor coolant filter	ASME III, Class C
Volume control tank	ASME III, Class C
Seal-water heat exchanger	ASME III, Class C, Tube Side; ASME VIII, Shell Side
Excess letdown heat exchanger	ASME III, Class C, Tube Side[b], ASME VIII, Shell Side
Chemical mixing tank	ASME VIII
Cation-bed demineralizer	ASME III, Class C
Boric acid storage tanks	ASME VIII
Deborating demineralizer	ASME III, Class C
Batching tank	ASME VIII
Seal-water injection filters	ASME III, Class C
Pumps	None
Boric acid filter	ASME VIII DIV I
Seal-water filter	ASME III, Class C
Resin fill tank	None
Piping and valves	USAS B31.1[c] and USAS B16.5[d]

a. ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

b. ASME VIII - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII - Division 1, Rules for Construction of Pressure Vessels Division 1 was used to fabricate tube bundle for 01-CH-E-4.

c. USAS B31.1 - Code for Pressure Piping, American Standards Association (supplemented by special nuclear cases where applicable).

d. USAS B16.5 - Code for Steel Pipe Flanges and Flanged Fittings, American Standards Association.

Table 9.1-2
CHEMICAL AND VOLUME CONTROL SYSTEM PRINCIPAL COMPONENT DATA SUMMARY

	Quantity per Unit	Heat Transfer Btu/hr	Design Letdown Flow. lb/hr	Maximum Letdown ΔT °F	Design Pressure, psig shell/tube	Design Temperature, °F shell/tube
I. Heat Exchangers						
Regenerative	1	8.3×10^6 (norm)	29,826	257.4	2485/2735	650/650
		15.4×10^6 (max)	59,700	236.4	2485/2735	650/650
Nonregenerative	1	16.0×10^6	59,700	265	150/600	250/400
Seal water	1	1.5×10^6	111,600	14	150/150	250/250
Excess letdown	1	3.1×10^6	7, 500	400.4	150/2485	250/650
	Quantity per Unit	Type	Capacity, gpm	Head, ft or psig	Design Pressure, psig	Design Temperature, °F
II. Pumps						
Charging	3[b]	Centrifugal	150[a]	5800 ft[a]	2735	250
Boric acid transfer	4[c]	Centrifugal	75	235 ft	150	250

a. Charging mode
b. can be shared by both units using charging cross-connect
c. Shared by both Units.

Table 9.1-2 (CONTINUED)
CHEMICAL AND VOLUME CONTROL SYSTEM PRINCIPAL COMPONENT DATA SUMMARY

	Quantity per Unit	Type	Volume	Design Pressure. psig	Design Temperature °F
III. Tanks					
Volume control	1	Vertical	300 ft^3	75 interior/ 15 exterior	250
Chemical mixing	1	Vertical	5 gal	150	250
Boric acid	3[d]	Vertical	7500 gal	Atmospheric	250
Batching	1[d]	Jacket Stm, bottom	800 gal	Atmospheric	250

d. Shared by both Units.

	Quantity per Unit	Type	Resin Volume, ft^3	Design Flow, gpm	Design Pressure, psig	Design Temperature, °F
IV. Demineralizers						
Mixed-bed	2	Flushable	30	120	200	250
Cation	1	Flushable	20	60	200	250
De-borating	2	Fixed	43	120	200	250

	Quantity per Unit	Design Flow, gpm	Design Temperature °F	Design Pressure, psig	Particle Retention (with 98% efficiency), µm
V. Filters					
Boric acid	1	320	250	200	≤25
Reactor coolant	1	320	250	200	≤25
Seal water	1	320	250	200	≤25
Seal water injection	2	80	200	2735	≤5
Letdown	1	325	250	200	

Table 9.1-3
CHEMICAL AND VOLUME CONTROL SYSTEM PERFORMANCE REQUIREMENTS[a]

Station design life	80 years[b]
Nominal pump seal-water supply flow rate (to reactor coolant pumps)	24 gpm (8 gal/pump)
Nominal pump seal-water return flow rate (from reactor coolant pumps)	9 gpm (3 gal/pump)
Normal letdown flow rate	60 to 120 gpm
Maximum design letdown flow rate	120 gpm
Normal charging pump flow rate (one pump including 60-gpm recirculation flow)	129 to 189 gpm
Normal charging line flow	45 to 105 gpm
Maximum rate of boration using 7% boric acid from the BASTs with one transfer and one charging pump, from initial reactor coolant system concentration of 0 ppm	14.1 ppm/min
Equivalent cooldown rate during the above rate of boration	4.9°F/min
Maximum rate of boron dilution with maximum design letdown flow rate at hot shutdown from initial reactor coolant system concentration of 2500 ppm	950 ppm/hr
Maximum rate of boration using 2400 ppm refueling water assuming an end of life reactor coolant system concentration of 0 ppm	5.5 ppm/min
Equivalent end of cycle cooldown rate during the maximum rate of boration	1.9°F/min
Temperature of reactor coolant entering system at full power with normal letdown and charging line flow rates	540.4°F
Temperature of reactor coolant return to reactor coolant system at full power	488°F
Normal system discharge temperature to boron recovery system	115°F
Approximate amount of 7.0% boric acid solution required to meet cold shutdown conditions	6000 gal[c]

a. Volumetric flow rates in gpm are based on 130°F and 2350 psig.

b. Original design life was 40 years. The evaluation and management of aging of components in this system demonstrate the acceptability of the design life of 80 years.

c. Range of boric acid concentration is 7.0 to 8.5%. The amount of solution is determined from the lower limit of concentration in order to obtain the more conservative figure.

Table 9.1-4
FISSION PRODUCT CONCENTRATIONS IN THE REACTOR COOLANT WITH SMALL CLADDING DEFECTS IN ONE PERCENT OF THE FUEL RODS[a]

Fission Product Isotope	Reactor Coolant Activity Concentration, µCi/cc at 560°F
A. Noble gases	
Kr-85	2.42 (peak)
Kr-85m	1.14
Kr-87	0.78
Kr-88	2.81
Xe-133	1.88×10^{2}
Xe-133m	1.87
Xe-135	5.20
Xe-135m	1.30×10^{-1}
Xe-138	3.50×10^{-1}
Subtotal	202.7
B. Nongaseous	
Br-84	3.0×10^{-2}
Rb-88	2.82
Rb-89	6.5×10^{-2}
Sr-89	2.8×10^{-3}
Sr-90	8.5×10^{-5}
Y-90	1.0×10^{-4}
Sr-91	1.3×10^{-3}
Y-91	4.9×10^{-4}
Sr-92	5.2×10^{-4}
Y-92	5.3×10^{-4}
Zr-95	5.4×10^{-4}
Nb-95	5.4×10^{-4}
Mo-99	2.23
Te-129	4.6×10^{-3}
I-129	2.4×10^{-8}
I-131	1.68
Te-132	1.86×10^{-1}
I-132	6.25×10^{-1}

a. Original plant design assumptions are stated in Table 9.1-5.

Table 9.1-4 (CONTINUED)
FISSION PRODUCT CONCENTRATIONS IN THE REACTOR COOLANT WITH SMALL CLADDING DEFECTS IN ONE PERCENT OF THE FUEL RODS[a]

Fission Product Isotope	Reactor Coolant Activity Concentration, µCi/cc at 560°F
I-133	2.73
Te-134	2.14×10^{-2}
I-134	3.8×10^{-1}
I-135	1.43
Cs-134	1.76×10^{-1}
Cs-136	2.6×10^{-2}
Cs-137	9.75×10^{-1}
Cs-138	4.58×10^{-2}
Ba-140	1.6×10^{-3}
La-140	6.2×10^{-4}
Ce-144	2.1×10^{-4}
Pr-144	2.3×10^{-4}
Subtotal	13.43
Total	216.13

Table 9.1-5
PARAMETERS USED IN THE CALCULATION OF REACTOR COOLANT FISSION PRODUCT ACTIVITIES FOR THE ORIGINAL PLANT DESIGN[a]

Core thermal power, maximum expected rating	2546 MWt
Fraction of fuel containing clad defects	0.01
Reactor coolant system liquid volume (including pressurizer at normal level)	9235 ft^3
Reactor coolant average temperature	560°F
Letdown purification flow rate (normal)	60 gpm
Effective cation demineralizer flow	6 gpm
Volume control tank volume	300 ft^3
Vapor	180
Liquid	120
Fission product escape rate coefficients, sec^{-1}	
Noble gas isotopes	6.5×10^{-8}
Br, I, and Cs isotopes	1.3×10^{-8}
Te isotopes	1.0×10^{-9}
Mo isotopes	2.0×10^{-9}
Sr and Ba isotopes	1.0×10^{-11}
Y, La, Ce, and Pr isotopes	1.6×10^{-12}
Mixed-bed demineralizer decontamination factors	
Noble gases and Cs-134, 136, 137, Y-90, and Mo-99	1.0 DF
All other isotopes (except tritium)	10.0 DF
Cation-bed demineralizer decontamination factor for Cs-134, 136, 137, Y-90, and Mo-99	10.0
Initial boron concentration (equilibrium cycle, hot full power)	1000 ppm
Boron dilution rate	3.46 ppm per full-power day

a. Original plant design parameters used in the determination of RCS fission product inventory include the core thermal power, RCS average temperature, letdown purification flow, and cycle length as indicated by the initial boron concentration.

Table 9.1-5 (CONTINUED)
PARAMETERS USED IN THE CALCULATION OF REACTOR COOLANT FISSION PRODUCT ACTIVITIES FOR THE ORIGINAL PLANT DESIGN[a] (CONTINUED)

Volume control tank noble gas stripping fraction (closed system)

Isotope	Stripping Fraction
Kr-85	2.3×10^{-5}
Kr-85m	2.7×10^{-1}
Kr-87	6.0×10^{-1}
Kr-88	4.3×10^{-1}
Xe-133	1.6×10^{-2}
Xe-133m	3.7×10^{-2}
Xe-135	1.8×10^{-1}
Xe-135m	8.0×10^{-1}
Xe-138	1.0

a. Original plant design parameters used in the determination of RCS fission product inventory include the core thermal power, RCS average temperature, letdown purification flow, and cycle length as indicated by the initial boron concentration.

Table 9.1-6
MAXIMUM VOLUME CONTROL TANK NOBLE GAS CONCENTRATION IN VAPOR PHASE WITH SMALL CLADDING DEFECTS IN ONE PERCENT OF THE FUEL RODS[a]

Isotope	Vapor Phase Activity Concentration µCi/cc
Kr-85	1.84
Kr-85m	36.3
Kr-87	7.30
Kr-88	38.6
Xe-133	3020.0
Xe-133m	32.8
Xe-135	67.8
Xe-135m	0.21
Xe-138	0.72
Total	3206 µCi/cc

a. Original plant design assumptions are stated in Table 9.1-5.

Table 9.1-7
TRITIUM SOURCES IN REACTOR COOLANT OPERATION
(ORIGINAL PLANT DESIGN)

Tritium Source [a]	Released to the Coolant (Ci/ yr)		
	Total Produced	Design Value	Expected value
Ternary fissions	7850	2355	78.5
Burnable poison rods [b] (initial cycle)	350	105	105
Control rods	0	0	0
Soluble poison boron			
Initial cycle [c]	270	270	270
Equilibrium cycle [d]	380	380	380
Li-7 reaction	9.2	9.2	9.2
Li-6 reaction	4.6	4.6	4.6
Deuterium reaction	1	1	1
Totals, initial cycle	8490	2745	468
Totals, equilibrium cycle	8250	2750	473

a. 12 month operating cycle, 2546 MWt at 0.8 load factor.

b. Weight of B_20_3 = 85# (B^{10} 5.23#).

c. Initial boron (hot, full-power, equilibrium xenon) = 700 ppm.

d. Initial boron (hot, full-power, equilibrium xenon) = 1000 ppm.

Table 9.1-8
BORIC ACID STORAGE TANK WATER CHEMISTRY

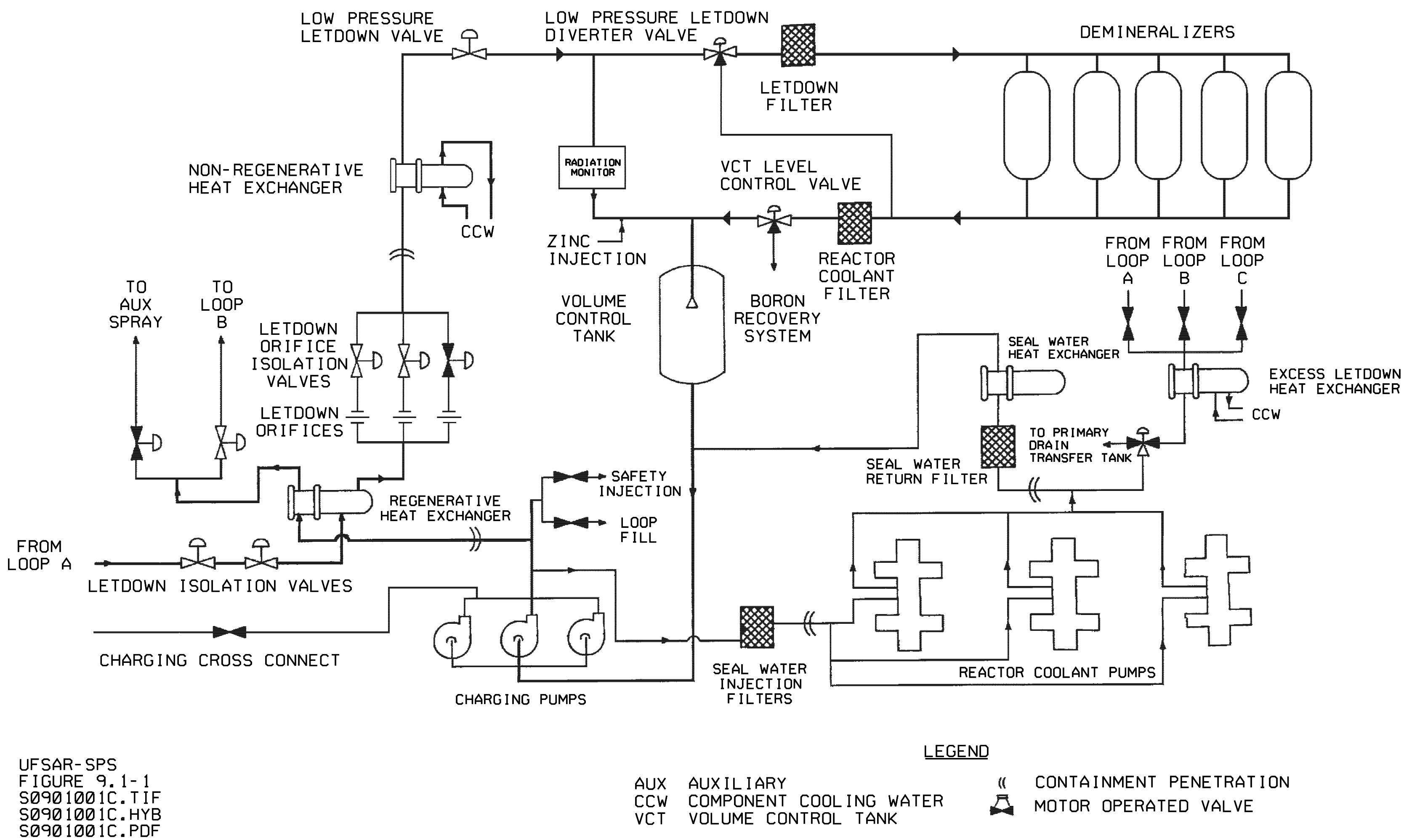
Chemistry Parameter	Requirement	Sampling Frequency
B	7.0 - 8.5% boric acid	Biweekly
$C1^{-}$	≤ 0.15 ppm	Monthly
F^{-}	≤ 0.250 ppm	Monthly

Note: Makeup water is of primary grade.

Table 9.1-9
CONSEQUENCES OF FAILURES OR MALFUNCTIONS OF THE CHEMICAL AND VOLUME CONTROL SYSTEM WITHIN THE REACTOR CONTAINMENT

Component	Failure	Comments and Consequences
Letdown line	Rupture in the line inside the reactor containment	The remote air-operated valve located near the main coolant loop is closed on low pressurizer level is to prevent supplementary loss of coolant through the letdown line rupture. The containment isolation valve in the letdown line outside the reactor containment is automatically closed by the containment isolation signal initiated by the concurrent loss- of- coolant accident. The closure of that valve prevents any leakage of the reactor containment atmosphere outside the reactor containment.
Charging line	Rupture in the line inside the reactor containment	The check valve located near the main coolant loop prevents supplementary loss of coolant through the line rupture. The air operated valve located upstream of the check valve in the defective line can be remote-manually closed to isolate the reactor coolant system from the rupture. The check valve located at the boundary of the reactor containment prevents any leakage of the reactor containment atmosphere outside the reactor containment.
Seal-water return line	Rupture in the line inside the reactor containment	The motor-operated isolation valve located outside the containment is manually closed or is automatically closed by the containment isolation signal initiated by the concurrent loss of-coolant accident. The closure of that valve prevents any leakage of the reactor containment atmosphere outside the reactor containment.

Figure 9.1-1 (SHEET 1 OF 2)
CHEMICAL AND VOLUME CONTROL SYSTEM



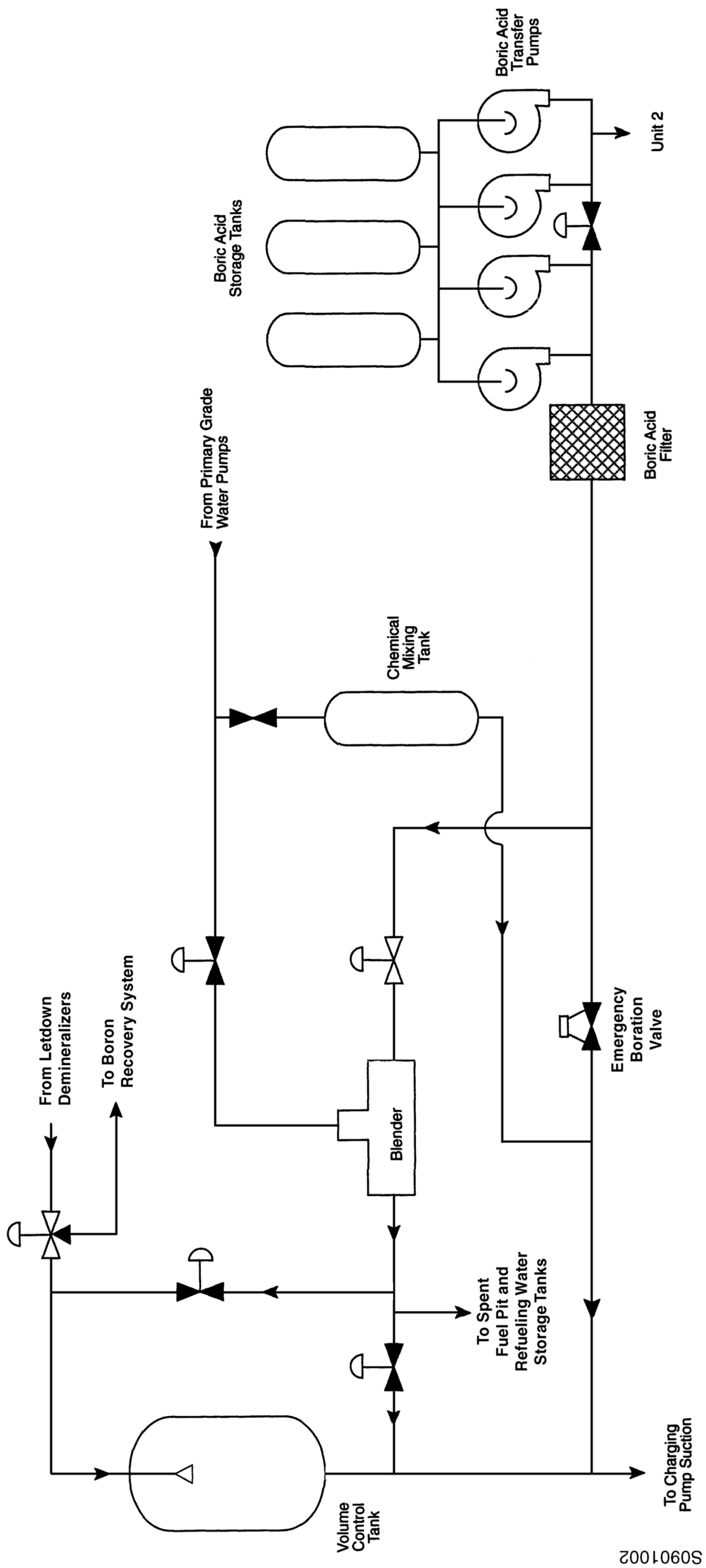


Figure 9.1-1 (SHEET 2 OF 2)
CHEMICAL AND VOLUME CONTROL SYSTEM

Intentionally Blank

9.2 BORON RECOVERY SYSTEM

The boron recovery system, shown in Figure 9.2-1 and Reference Drawings 1, 2, 3 and 4, is a common system serving both units. The system degasifies and stores borated radioactive water letdown by the chemical and volume control system (Section 9.1) to be processed as liquid waste for disposal. The boron recovery system is designed for liquid samples to be taken as appropriate for processing.

The original boron recovery system was designed to process letdown water by evaporators, filters, and demineralizers. This system was capable of producing both primary-grade water and a concentrated boric acid suitable for recycling within the chemical and volume control system. The original boron recovery evaporator and its associated filters and demineralizers are installed in the plant, but they are no longer used to process letdown water.

A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the boron recovery system was found to be adequate.

9.2.1 Design Bases

The original boron recovery system capacity was sized to accommodate the coolant letdown flow produced by two cold shutdowns from full power in one unit plus one cold shutdown from full power in the second unit in a 7-day period. These shutdowns are assumed to occur at that point in core life when the operating boron concentration in the first unit is 100 ppm and the boron concentration in the second unit is 1 month out of phase. The system influent results from shutdown boration bleed, draining one reactor coolant loop for maintenance work, system expansion during heat-up, and dilution bleed to operating boron concentration on start-up. The boron recovery tanks are assumed to be 10% full at the time of a cold shutdown, and the boron evaporators 75% available at rated capacity during the period.

The original boron recovery system was sized to accommodate letdown flow due to daily load following and weekend load reductions on both units to nearly the end of core life with 75% evaporator availability with minimum use of boron recovery tank capacity. The daily load-follow cycle basis consists of 12 hours at full power, a uniform 3-hour ramp reduction to 50% power, 6 hours at 50% power, and a uniform 3-hour ramp increase to full power.

The boron recovery system was modified to allow letdown water processing for disposal at the Radwaste Facility. This provides an additional 120,000-gallon surge capacity and a process rate of 25 gpm.

The system is capable of removing gases from both units simultaneously at the maximum letdown flow rate.

The boron evaporators are capable of processing the average letdown rate of both units producing a distillate with boron content not exceeding 10 ppm boron and concentrated bottoms at 12% boric acid. Although the boron evaporators are still physically installed in the plant, they are no longer used to process letdown water.

The primary drain tank, gas stripper, gas stripper overhead condenser, primary drain tank vent chiller condenser, overhead gas compressors, and gas stripper surge tank in the boron recovery system are designed as Class I components.

Piping in the boron recovery system is type 304 stainless steel and Incoloy 825. The Incoloy 825, which is used in those parts of the system associated with the processing of liquid waste or the concentration of boric acid, is resistant to corrosive attack by the solutions concentrated in the boron recovery system. All piping joints and connections are welded except where flanged connections are required to facilitate equipment removal for maintenance.

All globe valves handling radioactive gas are packless, diaphragm valves. All valves handling primary-grade water or radioactive fluid are stainless steel or Incoloy 825.

All liquid lines, equipment, and accessories containing concentrated boric acid (6% by weight boric acid or greater) are electrically heat-traced with dual circuits to prevent crystallization of boric acid. The boron recovery tanks and primary-grade water tanks are heated by steam. The evaporator bottoms tank is maintained, when in operation, at 150°F minimum by dual electric heaters.

The design data for the boron recovery system components are given in Table 9.2-1.

9.2.2 Description

The boron recovery system is illustrated in Figure 9.2-1 and Reference Drawings 1, 2, 3, and 4. Reactor coolant letdown, with entrained hydrogen and fission gases, enters the boron recovery system via the vent and drain system (Section 9.7). This liquid is pumped under automatic level control from the primary drain tank to the gas stripper, stripped of dissolved gases, and, if necessary, passed through ion exchangers for the removal of soluble fission and corrosion products. After subsequent filtration to remove additional particulate materials, the liquid is held up in the three boron recovery tanks for processing by the liquid waste system. Noncondensable gases removed in the gas stripper are taken off the gas stripper overhead condenser and discharged into the gas stripper surge tank by the overhead gas compressors. The surge tank discharges to the gaseous waste disposal system (Section 11.2.5); however, the capability exist to discharge to the volume control tank to return the hydrogen and radioactive gases to the reactor coolant system (Chapter 4). The surge tank contains sufficient gas to provide a cover gas for the gas stripper to prevent drawing in air, which could form a combustible mixture when the stripper is shut down.

The boron recovery system is designed so that operation of the primary drain tank and gas stripper is automatic when all system control setpoints are established. If used, operation of the evaporators is automatic upon cycle initiation from the control room.

Flanged connections have been provided on the boron recovery system next to the boron recovery tanks to enable the removal of radioactive gases and fluids to external process systems without having to enter high-radiation areas. The connections are provided with isolation valves, with reach rods also provided as needed. The valves and handwheels are so located as to permit access after an accident with reduced radiation exposure to personnel.

9.2.3 Design Evaluation

The design capacity of the gas stripper is 240 gpm, which corresponds to the maximum instantaneous letdown rate of both units. The stripper is controlled automatically at any letdown rate up to its maximum, with no operator action.

The boron recovery tanks, when 10% full, have an additional capacity of approximately 340,000 gallons and the Radwaste Facility has a surge capacity of approximately 120,000 gallons. During 7 days of operation at 75% availability, the radwaste liquid waste system can process approximately 190,000 gallons. This provides a total capability of approximately 650,000 gallons of letdown that can be stored or processed during any 7-day period. This capability is in excess of the estimated 450,000 gallons produced by three cold shutdowns.

9.2.3.1 **System Reliability**

Duplicate, full-capacity pumps and compressors are provided for all equipment except the boron evaporator recirculation pumps, evaporator bottoms tank recirculation pump, waste bottoms pump and the boron evaporator bottoms coolant pump. The primary-grade water pumps, primary drain tank pumps, gas stripper pumps, and gas stripper overhead compressor are provided with automatic controls to start the standby pump if the normal pump fails. The controls of all duplicate pumps are designed to permit alternate duty to equalize operating hours.

The components of this system listed in Section 9.2.1 are designed as Seismic Category I to resist earthquakes and are protected from possible tornado missiles by concrete walls or ceilings.

9.2.3.2 **Malfunction Analysis**

A failure analysis of boron recovery system components is present in Table 9.2-2.

9.2.4 Tests And Inspections

Tests, calibrations, and checks are periodically conducted on the various instrument channels to ensure proper instrument response and operation of alarm functions.

Standby pumps are switched on a periodic basis, and continuously running equipment is inspected periodically to ensure availability. Routine inspections are performed on this system in accordance with maintenance procedures to ensure that standby equipment will perform as required.

9.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-079A	Flow/Valve Operating Numbers Diagram: Boron Recovery System, Unit 1
2.	11448-FM-079B	Flow/Valve Operating Numbers Diagram: Boron Recovery System, Unit 1
3.	11448-FM-079C	Flow/Valve Operating Numbers Diagram: Boron Recovery System, Unit 1
4.	11448-FM-079D	Flow/Valve Operating Numbers Diagram: Boron Recovery System, Unit 1

Table 9.2-1
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Primary Drain Tank		
Number	1	
Capacity	5000 gal	
Design pressure	30 psig	
Design temperature	240°F	
Operating pressure	2 psig	
Operating temperature	125°F	
Material	SS 304	
Design code	ASME III C	
Gas Stripper		
Number	1	
Capacity	1248 gal	
Design pressure	50 psig	
Design temperature	300°F	
Operating pressure	2 psig	
Operating temperature	219°F	
Material	SS 316L	
Design code	ASME III C	
Boron Recovery Tanks		
Number	3 (one per unit)	
Capacity	127,000 gal	
Design pressure	0.5 psig	
Design temperature	180°F	
Operating pressure	Atmospheric	
Operating temperature	130°F	
Material	SS 304L	
Design code	API-650 [a]	
Boron Evaporators	"A" System	"B" System [b]
Number	1	1
Capacity, each	2900 gal	3130 gal
Design pressure	100 psig	100 psig
Design temperature	338°F	350°F
Operating pressure	15 psig	15 psig
Operating temperature	260°F	250°F
Material		
	"A" System	"B" System [b]
Bottoms	Stainless steel	Incoloy 825
Tower	Type 316L	SS 316
Design code	ASME IIIC	ASME VIII, Division I

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Primary-Water Tanks	
Number	2
Capacity, each	180,000 gal
Design pressure	0.5 psig
Design temperature	140°F
Operating pressure	Atmospheric
Operating temperature	125°F
Material	SS 304L
Design code	API-650 [a]
Evaporator Bottoms Tank	
Number	1
Capacity	4000 gal
Design pressure	25 psig
Design temperature	200°F
Operating pressure	Atmospheric
Operating temperature	160°F
Material	SS 316L
Design code	ASME III C
Distillate Accumulators	
Number	2
Capacity, each	550 gal
Design pressure	100 psig
Design temperature	338°F
Operating pressure	15 psig
Operating temperature	250°F
Material	SS 304
Design code	ASME III C
Gas Stripper Surge Tank	
Number	1
Capacity	550 gal
Design pressure	200 psig
Design temperature	300°F
Operating pressure	125 psig
Operating temperature	150°F
Material	SS 304
Design code	ASME III C
Test Tanks	
Number	2
Capacity, each	30,000 gal
Design pressure	0.5 psig
Design temperature	140°F

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.

b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Test Tanks (continued)		
Operating pressure	Atmospheric	
Operating temperature	125°F	
Material	SS 304L	
Design code	API-650 [a]	
Stripper Feed Heat Exchangers		
Number	2	
Total duty	18,000,000 Btu/hr (9,000,000 Btu/hr each heater)	
	Shell	Tube
Design pressure	200 psig	150 psig
Design temperature	300°F	200°F
Operating pressure	125 psig	100 psig
Operating temperature, in/out	219/144°F	100/175°F
Material	SS 304	SS 304
Fluid	Letdown	Letdown
Design code	ASME III C	ASME III C
Stripper Feed Steam Heaters		
Number	2	
Total duty	7,800,000 Btu/hr (3,900,000 Btu/hr each heater)	
	Shell	Tube
Design pressure	200 psig	150 psig
Design temperature	388°F	338°F
Operating pressure	100 psig	100 psig
Operating temperature, in/out	338/338°F	175/240°F
	Shell	Tube
Material	Carbon steel	SS 304
Fluid	Steam	Letdown
Design code	ASME VIII	ASME III C
Stripper Trim Cooler		
Number	1	
Total duty	1,700,000 Btu/hr	
Design pressure	150 psig	200 psig
Design temperature	150°F	220°F
Operating pressure	75 psig	75 psig
Operating temperature, in/out	105/112°F	144/130°F
Material	Carbon steel	SS 304
Fluid	Component cooling water	Letdown
Design code	ASME III C	ASME III C

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Stripper Overhead Condenser		
Number	1	
Total duty	2,800,000 Btu/hr	
	Shell	Tube
Design pressure	150 psig	150 psig
Design temperature	300°F	300°F
Operating pressure	2 psig	75 psig
Operating temperature, in/out	219/219°F	105/116°F
Material	SS 304	SS 304
Fluid	Distillate	Component cooling water
Design code	ASME III C	ASME III C
Primary Drain Tank Vent Chiller Condenser		
Number	1	
Total duty	20,000 Btu/hr	
	Shell	Tube
Design pressure	150 psig	150 psig
Design temperature	300°F	300°F
Operating pressure	2 psig	75 psig
Operating temperature, in/out	219/130°F	75/77°F
Material	SS 304	SS 304
	Shell	Tube
Fluid	Distillate	Chilled component cooling water
Design code	ASME III C	ASME III C
Boron Evaporator Reboilers "A" System		
Number	1	
Duty	11,100,000 Btu/hr	
	Shell	Tube
Design pressure	200 psig	100 psig
Design temperature	382°F	300°F
Operating pressure	100 psig	25 psig
Operating temperature, in/out	338/338°F	253/263°F
Material	Carbon steel	SS 304
Fluid	Steam	1-12% boric acid
Design code	ASME III	ASME III C
Boron Evaporator Reboilers [b] "B" System		
Number	1	
Duty	12,330,000 Btu/hr	
Design pressure	200 psig	100 psig
Design temperature	400°F	350°F
Operating pressure	100 psig	22 psig

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Boron Evaporator Reboilers [b] (continued) "B" System		
Operating temperature, in/out	338/338°F	253/264°F
Material	Carbon steel	Incoloy 825
Fluid	Steam	1-12% boric acid
Design code	ASME VIII	ASME VIII, 1971
Boron Evaporator Distillate Coolers [b]		
Number	2	
Duty, each	1,150,000 Btu/hr	
	Shell	Tube
Design pressure	100 psig	150 psig
Design temperature	338°F	338°F
Operating pressure	50 psig	75 psig
Operating temperature, in/out	240/125°F	105/139°F
Material	SS 304	SS 304
Fluid	Distillate	Component cooling water
Design code	ASME III C	ASME III C
Boron Evaporator Bottoms Cooler [b]		
Number	1	
Total duty	950,000 Btu/hr	
	Shell	Tube
Design pressure	150 psig	150 psig
Design temperature	300°F	300°F
Operating pressure	85 psig	45 psig
Operating temperature, in/out	150/170°F	150/160°F
Material	Carbon steel	SS 304
Fluid	Component cooling water	12% boric acid
Design code	ASME III C	ASME III C
Boron Recovery Tank Heaters		
Number	3	
Duty, each	670,000 Btu/hr	
	Shell	Tube
Design pressure	200 psig	200 psig
Design temperature	388°F	388°F
Operating pressure	100 psig	30 psig
Operating temperature, in/out	338/338°F	40/250°F
Material	Carbon steel	SS 304
Fluid	Steam	Letdown
Design code	ASME VIII	ASME III C

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Primary-Water Tank Heaters		
Number	2	
Duty, each	670,000 Btu/hr	
	Shell	Tube
Design pressure	200 psig	200 psig
Design temperature	388°F	388°F
Operating pressure	100 psig	30 psig
Operating temperature, in/out	338/338°F	40/250°F
Material	Carbon steel	SS 304
Fluid	Steam	Water
Design code	ASME VIII	ASME III C
Primary-Drain Tank Pumps		
Number	2 (one required)	
Type	Horizontal centrifugal	
Motor horsepower	20 hp	
Seal type	Canned pump	
Capacity, each	240 gpm	
Head at rated capacity	222 ft	
Design pressure	150 psig	
Materials		
Pump casing	SS 316	
Shaft	SS 316	
Impeller	SS 316	
Gas Stripper Circulating Pumps		
Number	2 (one required)	
Type	Horizontal centrifugal	
Motor horsepower	30 hp	
Seal type	Mechanical seal with backup breakdown section	
Capacity, each	240 gpm	
Head at rated capacity	250 ft	
Design pressure	200 psig	
Materials		
Pump casing	SS 316	
Shaft	SAE 4140	
Impeller	SS 316	
Boron Evaporator Feed Pumps		
Number	2 (one required)	
Type	Horizontal centrifugal	
Motor horsepower	10 hp	
Seal type	Mechanical seal with backup breakdown section	
Capacity, each	150 gpm	

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Boron Evaporator Feed Pumps (continued)	
Head at rated capacity	117 ft
Design pressure	225 psig
Materials	
Pump casing	SS 316
Shaft	SAE 4140
Impeller	SS 316
Boron Evaporator Circulating Pumps [b]	
Number	2
Type	Horizontal centrifugal
Motor horsepower	50 hp
Seal type	Double mechanical
Capacity, each	2200 gpm
Head at rated capacity	60 ft
Design pressure	230 psig
Materials	
Pump casing	SA 296, Gr. CN-7M
Shaft	SAE 4140
Impeller	SA 266, Gr. CN-7M
Boron Evaporator Bottoms Pumps [b]	
Number	2 (one required)
Type	Horizontal centrifugal
Motor horsepower	1.5 hp
Seal type	Canned pump
Capacity, each	20 gpm
Head at rated capacity	56 ft
Design pressure	150 psig
Materials	
Pump casing	SS 316
Shaft	SS 316
Impeller	SS 316
Boron Evaporator Bottoms Cooler Circulating Pump [b]	
Number	1
Type	Horizontal centrifugal
Motor horsepower	1.5 hp
Seal type	Mechanical
Capacity, each	50 gpm
Head at rated capacity	30 ft
Design pressure	150 psig
Materials	
Pump casing	Cast iron

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Boron Evaporator Bottoms Cooler Circulating Pump [b] (continued)	
Shaft	Carbon steel
Impeller	Cast iron
Boron Evaporator Bottoms Tank Circulating Pump [b]	
Number	1
Type	Horizontal centrifugal
Motor horsepower	1.5 hp
Seal type	Canned pump
Capacity, each, gpm	50 gpm
Head at rated capacity	52 ft
Design pressure	150 psig
Materials	
Pump casing	SS 316
Shaft	SS 316
Impeller	SS 316
Boron Evaporator Distillate Pumps [b]	
Number	2
Type	Horizontal centrifugal
Motor horsepower	5 hp
Seal type	Mechanical
Capacity, each	22 gpm
Head at rated capacity	140 ft
Design pressure	225 psig
Materials	
Pump casing	SS 316
Shaft	SAE 4140
Impeller	SS 316
Test Tanks Pumps	
Number	2 (one required)
Type	Horizontal centrifugal
Motor horsepower	10 hp
Seal type	Mechanical
Capacity, each	100 gpm
Head at rated capacity	142 ft
Design Pressure	225 psig
Materials	
Pump casing	SS 316
Shaft	SAE 4140
Impeller	SS 316

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Primary-Water Supply Pumps	
Number	2 (one required)
Type	Horizontal centrifugal
Motor horsepower	30 hp
Seal type	Mechanical
Capacity, each	350 gpm
Head at rated capacity	255 ft
Design pressure	225 psig
Materials	
Pump casing	SS 316
Shaft	SAE 4140
Impeller	SS 316
Waste Bottoms Pump [b]	
Number	1
Type	Horizontal centrifugal
Motor horsepower	3 hp
Capacity	10 gpm
Head at rated capacity	70 ft
Design pressure	175 psig
Materials	
Pump casing	SA 296, Gr. CN-7M
Shaft	SA 322, Gr. 4140
Impeller	SA 296, Gr. CN-7M
Overhead Gas Compressor	
Number	2 (one required)
Type	Diaphragm
Motor horsepower	10 hp
Capacity, each	2.5 scfm
Discharge pressure at capacity	125 psig
Design pressure	200 psig
Materials	
Cylinder	Carbon steel
Piston rod	Forged steel
Piston	Nodular iron
Diaphragm and parts contacting gas	SS 302/304 or SS 316
Boron Recovery Filters	
Number	2 (one required)
Retention size	1-3 microns
Filter element material	Fiber
Capacity, normal	240 gpm
Capacity, maximum	300 gpm

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.

b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Boron Recovery Filters (continued)	
Housing material	SS 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III C
Boron Evaporator Bottoms Filters [b]	
Number	2 (one required)
Retention size	25 microns
Filter element material	Fiber
Capacity, normal	20 gpm
Capacity, maximum	50 gpm
Housing material	SS 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III C
Boron Cleanup Filter	
Number	1
Retention size	5 microns
Filter element material	Fiber
Capacity, normal	100 gpm
Capacity, maximum	130 gpm
Housing material	SS 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III C
Cesium Removal Ion Exchangers	
Number	2 (one required)
Design flow	25 gpm/ft^2
Resin type	Cation, mono bed
Resin active volume	45 ft^3
Design pressure	200 psig
Design temperature	250°F
Material	SS 316
Design code	ASME III C

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-1 (CONTINUED)
BORON RECOVERY SYSTEM COMPONENT DESIGN DATA

Boron Cleanup Ion Exchanger (Boron Evaporator Feedwater Demineralizer)

Number	2 (one required)
Design flow	10.5 gpm/ft^2
Resin type	Cation-anion, mixed-bed
Resin active volume	45 ft^3
Design pressure	200 psig
Design temperature	250°F
Material	SS 316
Design code	ASME III C

a. In addition to the API-650 Code, the construction process incorporated the requirements of ASME Code Section III C for welding, welding procedure qualification, weld joint efficiency, and weld inspection.
b. Installed but not used.

Table 9.2-2
BORON RECOVERY SYSTEM MALFUNCTION ANALYSIS

Component	Malfunction	Comments and Consequences
Tanks and other components containing letdown liquids with dissolved gasses	Leak	Tanks and other components are protected from over-pressure by automatic controls and relief valves; therefore only minor leaks are considered possible. The total gas content of the gas stripper and associated gas holding tanks is less than the holdup tanks in the gaseous waste gas disposal system (Section 14.4.2), so even a total release via the auxiliary vent system could be accommodated (Section 9.13).
Boron recovery tanks	Leak	Only degassed liquids are normally stored in these tanks, which are protected by dikes capable of retaining the entire contents of the tank. The dikes are Class I structures.
Gas stripper and associated pumps, heater, and controls	Fail to function	Letdown due to boration of the reactor coolant system can be diverted directly to the boron recovery tanks, which are vented through the monitored gaseous waste disposal system. Dilution letdown can be delayed.
One boron recovery evaporator or auxiliaries	Fails to function	The boron recovery evaporators are no longer used to process CVCS letdown. Letdown is processed as liquid waste in the Radwaste Facility by either reverse osmosis and ion exchange or by the radwaste facility evaporators. Furthermore, the Radwaste Facility has an additional collection/surge capacity of approximately 120,000 gallons. Multiple processing options ensure that sufficient letdown processing capacity is available while repairs are being made. Sufficient capability to make boric acid solution for station requirements exists in the boric acid batch tanks, and the primary-grade water tanks can supply adequate quantities of water.
Primary-grade water pump	Fails to function	Two 100%-capacity pumps are provided to permit maintenance.

Figure 9.2-1 (SHEET 1 OF 4)
BORON RECOVERY SYSTEM

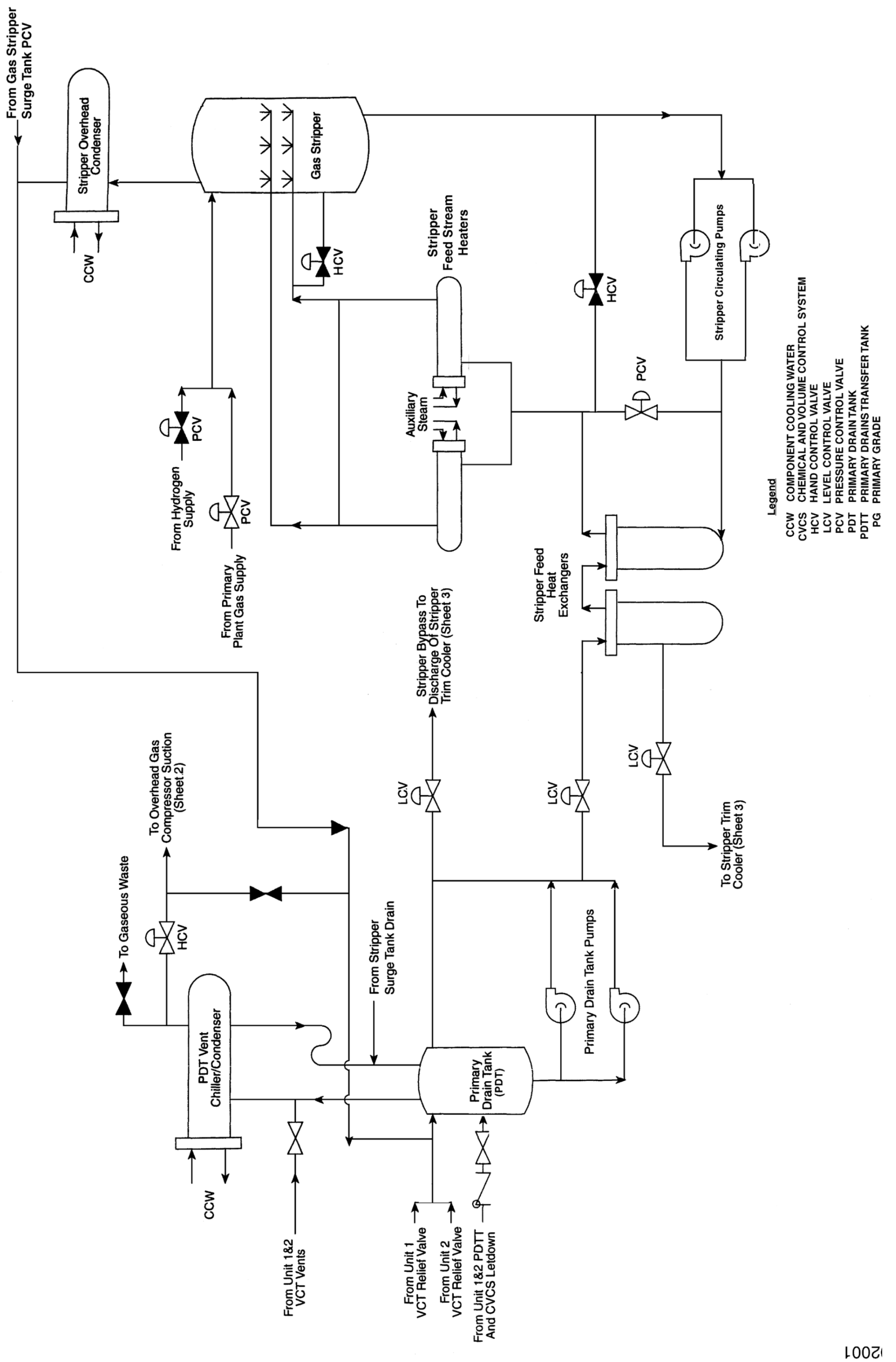
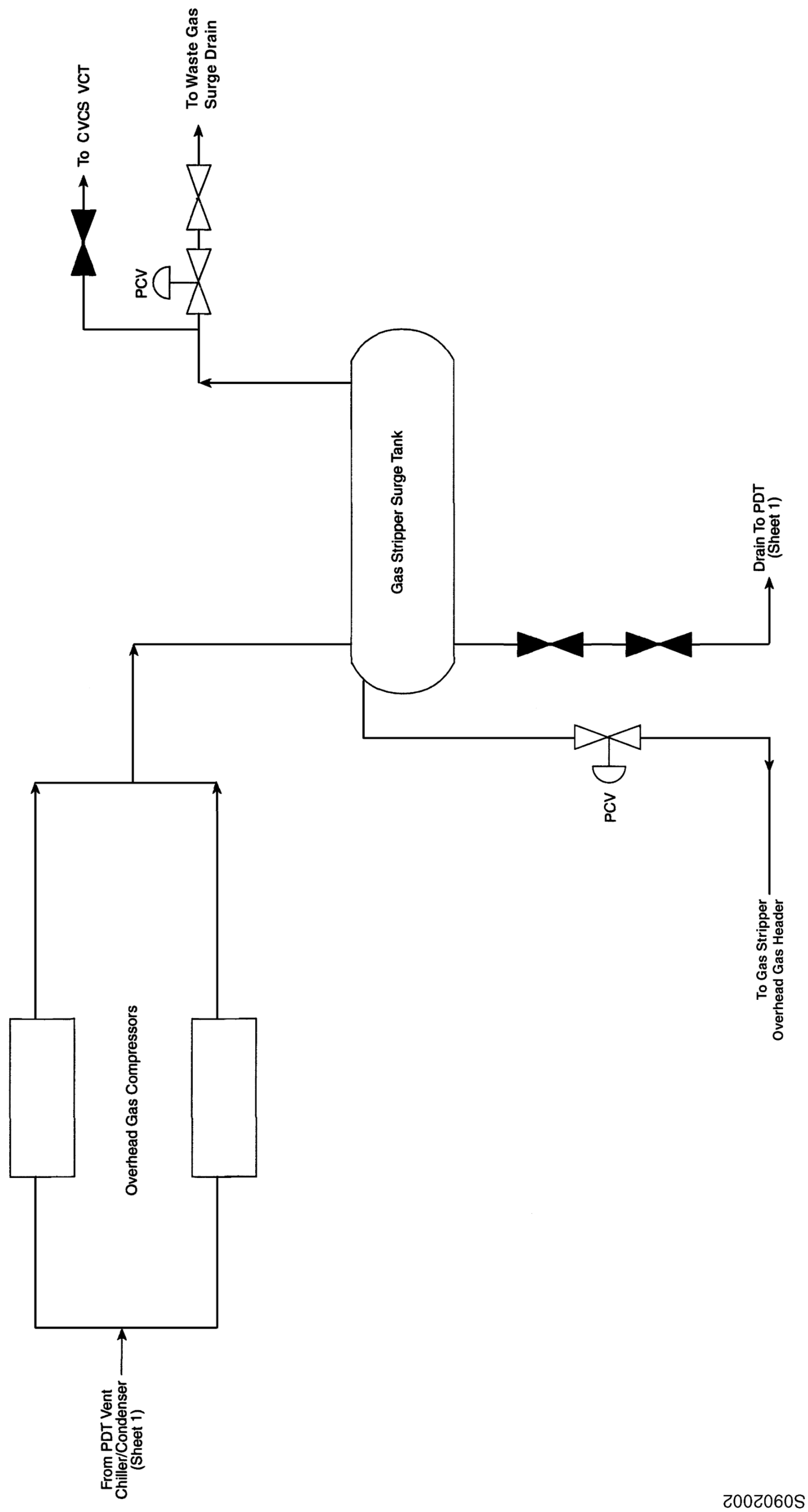


Figure 9.2-1 (SHEET 2 OF 4)
BORON RECOVERY SYSTEM



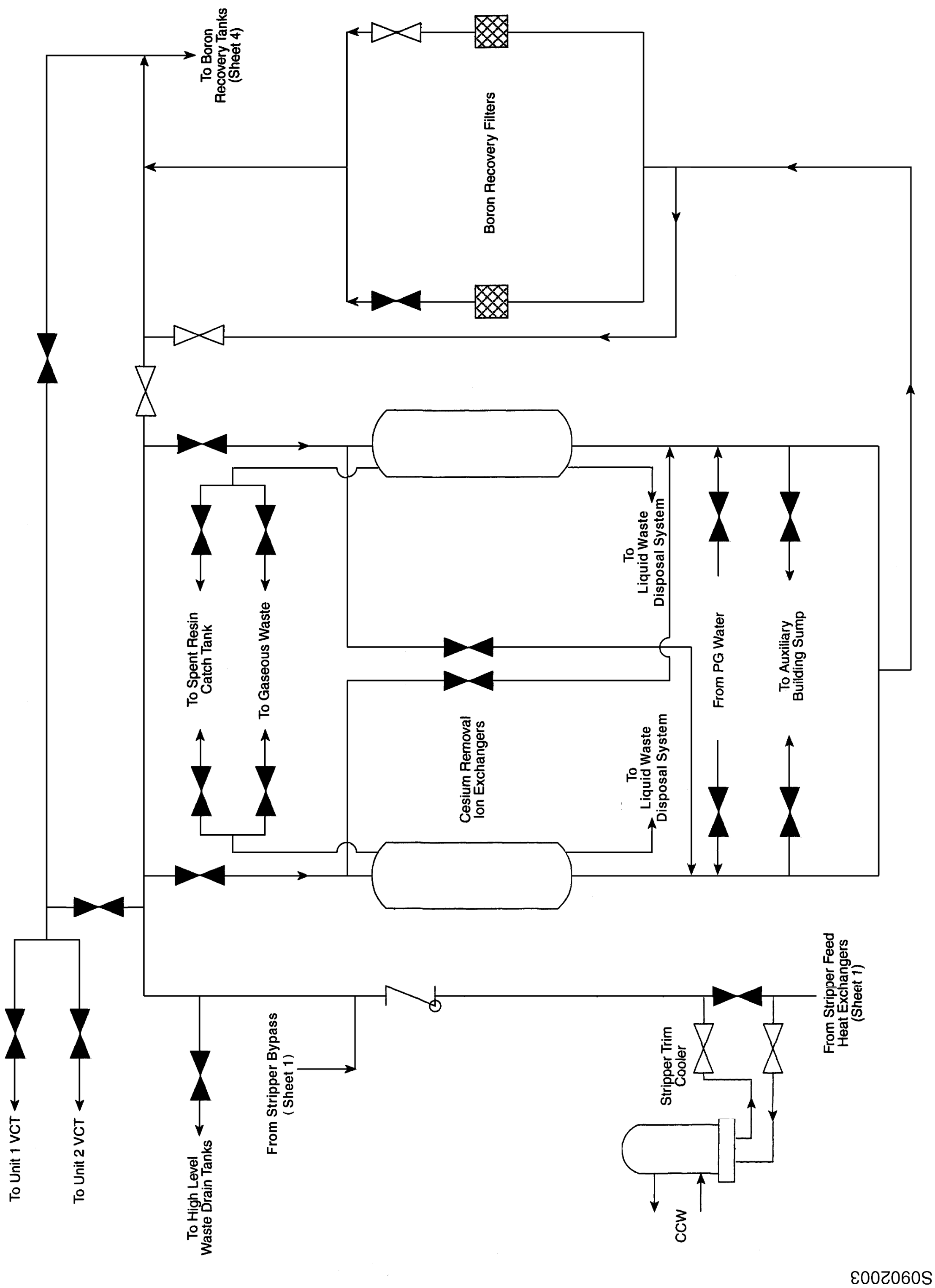
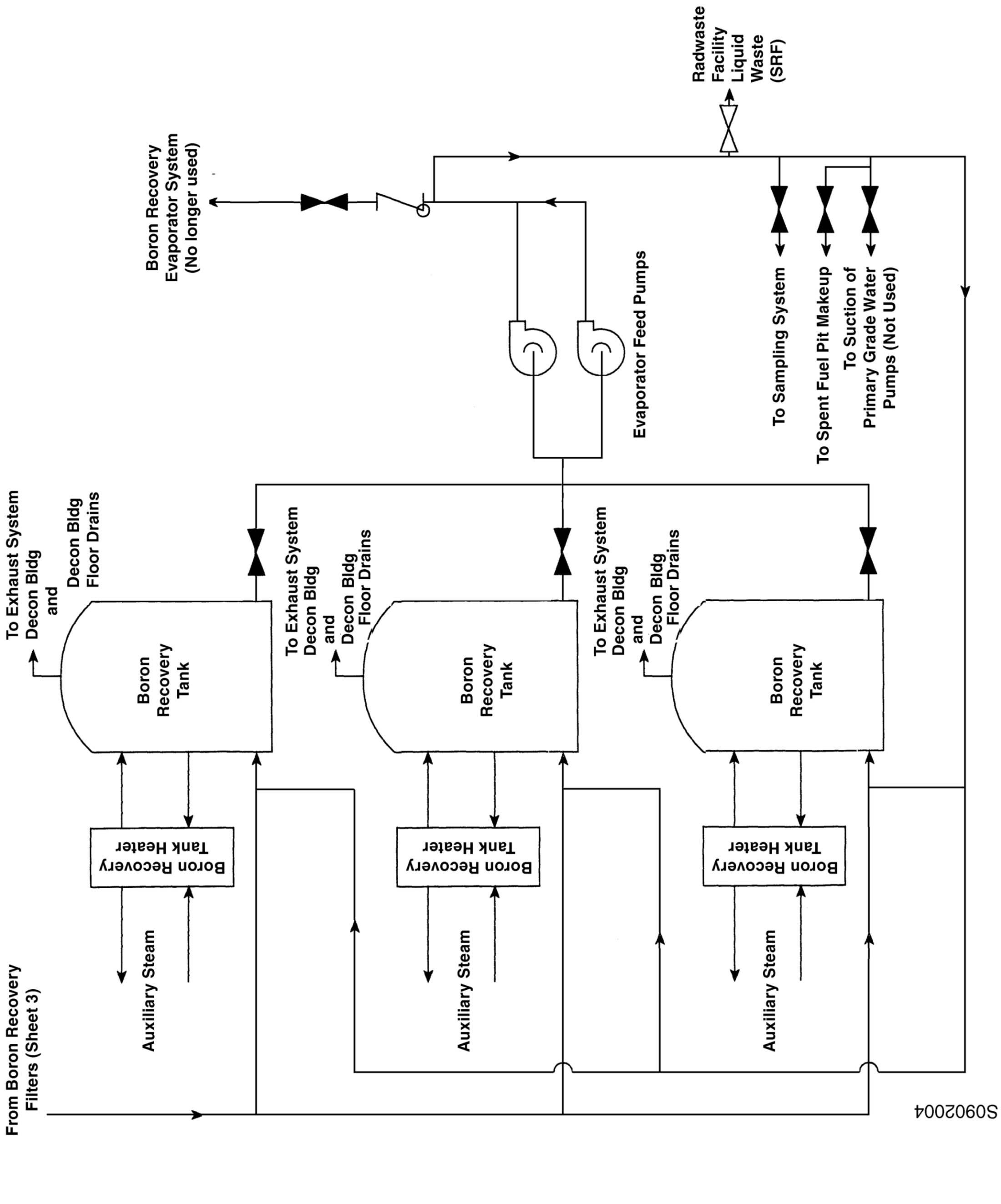


Figure 9.2-1 (SHEET 3 OF 4)
BORON RECOVERY SYSTEM

Figure 9.2-1 (SHEET 4 OF 4)
BORON RECOVERY SYSTEM



9.3 RESIDUAL HEAT REMOVAL SYSTEM

9.3.1 Design Bases

The residual heat removal system is shown in Figure 9.3-1 and Reference Drawing 1. It is designed to remove residual and sensible heat from the core and reduce the temperature of the reactor coolant system during the second phase of unit cooldown. During the first phase of cooldown, the temperature of the reactor coolant system is reduced by transferring heat from the reactor coolant system (Chapter 4) to the steam and power conversion system (Chapter 10).

The residual heat removal system is designed to be placed in operation when the reactor coolant temperature has been reduced to approximately 350°F and the reactor coolant pressure is between 400 and 450 psig. These conditions are assumed to occur approximately 4 hours after reactor shutdown. The residual heat removal system is designed to reduce the temperature of the reactor coolant from 350°F to 140°F over a period of 16 hours. With one pump in service, the residual heat removal system can reduce the temperature of the reactor coolant from 350°F to 200°F within 26 hours, and from 200°F to 140°F prior to beginning refueling operations.

The system design precludes any significant reduction in the overall design reactor shutdown margin when the system is brought into operation for residual heat removal by equalizing the boron concentration and the temperature with the reactor coolant system.

System components, whose design pressure and temperature are less than the reactor coolant system design limits, are provided with redundant isolation means and overpressure protective devices.

A residual heat removal system is provided for each unit.

Any leakage from the residual heat removal system goes either to the containment or to the component cooling system, which is a closed system. Any migration of radioactivity would be detected by the containment particulate and gas monitors (Section 11.3) if the leak was to the containment. If the leak was to the component cooling system, the component cooling water monitor would alarm in the event that the radiation level reached a preset level above the normal background.

All active system components that are relied upon to perform their function are redundant, and the system design includes provisions to enable periodic hydrostatic testing to applicable code test pressures.

9.3.1.1 **Codes and Classifications**

All piping and components of the residual heat removal system are designed to the applicable codes and standards listed in Table 9.3-1. Since the system contains reactor coolant when it is in operation, austenitic stainless steel piping is used. The residual heat removal system is a Seismic Class I system.

9.3.2 System Design and Operation

9.3.2.1 System Description

The residual heat removal system, shown in Figure 9.3-1 and Reference Drawing 1, consists of two residual heat exchangers, two residual heat removal pumps, and associated piping, valves, and instrumentation.

One pump and one residual heat exchanger are enough to perform the decay heat transfer functions for the unit. After the reactor coolant system temperature has been reduced to approximately 350°F and the reactor coolant pressure is between 400 and 450 psig, further system cooling is initiated by aligning the pumps to take suction from the reactor coolant hot leg and discharge through the heat exchangers into the reactor coolant cold leg.

During unit cooldown, reactor coolant flows from the reactor coolant system to the residual heat removal pumps, through the tube side of the residual heat exchangers, and back to the reactor coolant system. The inlet line to the residual heat removal system is located in the hot leg of reactor coolant loop A between the main loop stop valve and the reactor core. The return line connects to the B & C through the safety injection system. The heat loads are transferred by the residual heat exchangers to the component cooling water in the component cooling system (Section 9.4).

During unit cooldown, the cooldown rate of the reactor coolant is controlled by regulating the flow through the tube side of the residual heat exchangers. A single bypass line with a remotely operated control valve around both residual heat exchangers is used to maintain a constant coolant flow through the residual heat removal system while controlling coolant temperature.

To assure that adequate head is available for the RHR pumps during cold shutdown (reactor coolant level below Elevation 24 ft.) and during refueling, reactor coolant level monitoring is available. Level instrumentation to prevent loss of shutdown cooling is discussed in Section 7.11.

The entire residual heat removal system is located inside the containment, with the exception of the line penetrating the containment that connects to the refueling water storage tank.

The residual heat removal pumps are normally controlled from the control room. In the event of a control room evacuation, pumps can be operated at the switchgear in the emergency switchgear room. See Section 7.7.2 for discussion on compliance with 10 CFR 50 Appendix R.

During refueling, the water level in the reactor cavity is lowered by opening a valve at the residual heat removal pump discharge and then pumping the water into the refueling water storage tank, while maintaining as adequate flow to the RHR heat exchanger(s) to ensure the continued removal of residual heat from the core.

The RHR system air operated valves are equipped with quick-disconnect instrument air fittings to provide a method to locally operate the valves with a portable air source. The operation of these valves is required for decay heat removal during plant cooldown following a postulated fire in accordance with the requirements of Appendix R to 10 CFR 50.

The residual heat removal system is not an engineered safeguards system.

9.3.2.2 **Components**

Residual heat removal system component design data are listed in Table 9.3-2.

9.3.2.2.1 Residual Heat Exchangers

The residual heat exchangers are of the shell and U-tube type, with the tubes welded to the tube sheet. Reactor coolant circulates through the tubes while component cooling water circulates through the shell side. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel, and the shell is carbon steel.

9.3.2.2.2 Residual Heat Removal Pumps

The two residual heat removal pumps are in-line vertical centrifugal units with mechanical seals to prevent reactor coolant leakage. All pump parts in contact with reactor coolant are austenitic stainless steel or adequate corrosion-resistant material.

9.3.2.2.3 Residual Heat Removal System Valves

The valves used in the residual heat removal system are constructed of austenitic stainless steel or other adequate corrosion-resistant materials, such as Haynes alloy 25 and 17-4 PH stainless steel.

Manual stop valves are provided to isolate the pumps or the heat exchangers for maintenance. Butterfly valves are provided for control of residual heat exchanger tube-side flow. Check valves prevent reverse flow through the residual heat removal pumps.

Isolation of the residual heat removal system is achieved with two remotely operated stop valves in series in the pipe from a reactor hot leg to the suction side of the residual heat removal pump, and by a check valve (located in the safety injection system) in series with a remotely operated stop valve in each line from the residual heat removal system. System pressure is relieved through a relief valve to the pressurizer relief tank in the reactor coolant system.

Several motor operated valves in the RH System have been modified to prevent valve pressure locking. The valves have been modified to relive pressure that can be trapped between the gate valve disks. The following MOVs have been modified by drilling a hole in the downstream disk: 1-RH-MOV-1720A,B.

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the vent and drain system (Section 9.7).

Manually operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakoff connections are provided where required by valve size and fluid conditions.

9.3.2.2.4 Residual Heat Removal System Piping

All residual heat removal system piping is austenitic stainless steel. Piping is welded, except at the flanged connections of the flow control valves.

Portions of the residual heat removal system potentially contain stagnant oxygenated borated water during plant operation (References 1 & 2). System integrity is maintained by means of periodic sampling and inservice inspection requirements. Residual heat removal system chemistry guidelines are given in Table 9.3-3.

9.3.3 System Design Evaluation

9.3.3.1 **Availability and Reliability**

For reactor coolant system cooldown, the residual heat removal system is provided with two pumps and two residual heat exchangers. If one of the two pumps and/or one of the two heat exchangers is not operative, safe operation of the unit is not affected.

A radiant energy shield is installed between the residual heat removal pump motors to satisfy 10 CFR 50, Appendix R, requirements.

9.3.3.2 **Incident Control**

The suction side of the residual heat removal system is connected to the reactor coolant hot leg of A loop and the discharge side to the cold legs of the B & C loops through the safety injection system. On the suction side, the connection is through two electric motor-operated gate valves in series. Both valves are interlocked with reactor coolant system pressure so that, if the reactor coolant system pressure exceeds a set pressure, the valves do not open. On the discharge side of the residual heat removal system, each connection is made through an electric motor-operated valve in series with a check valve. The motor-operated valves are closed whenever the reactor coolant system pressure and temperature exceed approximately 450 psig and 350°F, respectively.

The fluid operating pressure is higher at all times on the tube side of the residual heat exchanger than on the shell side, varying over an approximate range of 450 to 100 psig, so that in case of leakage, reactor coolant leaks into the component cooling water in the shell side. Abnormally high radiation levels in the component cooling water would be indicated in the control room, at which time the control valve in the vent line from the component cooling surge tank to the process vent would be closed by manual operation of a control switch in the control room, if it had not previously closed automatically due to high-radiation signals from transmitters installed in the component cooling water piping. Inleakage to the component cooling water, if not stopped, results in high level in the component cooling surge tank, and eventually fills the tank.

Excess water from the tank is disposed of by a relief valve discharging to the auxiliary building sump. After the leakage condition is corrected, radioactivity in the component cooling water is reduced by bleed and feed or as discussed in Section 9.4.4.7.

The residual heat removal pumps are driven by drip-proof-type motors with Class B epoxy-type insulation capable of operation in high-humidity conditions. They are equipped with splash barriers to protect the motors in the event of a pipeline break in the area, which could possibly spray and wet the motors.

The inlet line from the reactor coolant system to the residual heat removal system is between the reactor core and the outlet loop isolation valve. Thus, if the outlet or inlet loop isolation valve is closed, the inlet from the reactor coolant system to the residual heat removal system is not blocked.

9.3.3.3 **Malfunction Analysis**

A failure analysis of residual heat removal pumps, heat exchangers, and valves is presented in Table 9.3-4.

9.3.4 Tests and Inspections

The residual heat removal pump flow instrument channels are calibrated during each refueling operation.

The active components of the residual heat removal system are tested in accordance with ASME Code requirements. Periodic visual inspections and preventative maintenance are conducted, following normal industrial practice.

9.3 REFERENCES

1. U. S. Nuclear Regulatory Commission, *IE Bulletin 79-17*, *Pipe Cracks in Stagnant Borated Water Systems at PWR Plants,* July 26, 1979.
2. Virginia Electric and Power Company, *Response to IE Bulletin 79-17,* August 30, 1979.

9.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-087A	Flow/Valve Operating Numbers Diagram: Residual Heat Removal System, Unit 1

Table 9.3-1
RESIDUAL HEAT REMOVAL SYSTEM CODE REQUIREMENTS

Residual heat exchangers	Unit 1 (1-RH-E-1A only): ASME III, Class C, tube side ASME VIII, shell side Unit 1 (1-RH-E-1B only) ASME III, Class 2, tube side ASME III, Class 3, shell side Unit 2 (2-RH-E-1A only): ASME III, Class C, tube side ASME VIII, shell side Unit 2 (2-RH-E-1B only): ASME III, Class 2, tube side ASME III, Class 3, shell side
Residual heat removal piping and valves	USAS B31.1
Residual heat removal pumps	No code

Table 9.3-2
RESIDUAL HEAT REMOVAL SYSTEM DESIGN DATA

General system design, including piping and valves	
Design pressure	600 psig
Design temperature	400°F
Residual heat removal pumps	
Quantity	2
Type	In-line centrifugal
Capacity, each	4000 gpm
Head at rated capacity	230 ft H_2O
Motor horsepower	300 hp
Material	Austenitic stainless steel and equivalent corrosion-resistant materials
Design pressure	600 psig
Design temperature	400°F
Seal type	Mechanical
Residual heat exchangers	
Quantity	2
Type	Shell and U-tube
Design heat transfer rate, each	33×10^6 Btu/hr
Shell (component cooling water)	
Design temperature	200°F
Design pressure	150 psig
Design flow rate	4.45×10^6 lb/hr
Design inlet temperature	105°F
Design outlet temperature	112°F
Material	Carbon steel
Tube (reactor coolant)	
Design temperature	400°F
Design pressure	600 psig
Design flow rate	2.0×10^6 lb/hr
Design inlet temperature	140°F
Design outlet temperature	124°F (1-RH-E-1A and 2-RH-E-1A) 123°F (1-RH-E-1B and 2-RH-E-1B)
Material	Austenitic stainless steel

Table 9.3-3
RESIDUAL HEAT REMOVAL SYSTEM CHEMISTRY GUIDELINES

Chemistry Parameter [a]	Requirement
pH at 25°C [b]	≈4.5
Conductivity at 25°C	< 1 to 40 μmhos [b]
Suspended solids	1.0 ppm max
B	≈2500 ppm
$C1^-$	0.15 ppm max
F^-	0.15 ppm max
O_2 [c]	0.10 ppm max

a. Sampling is performed when the system is in operation.

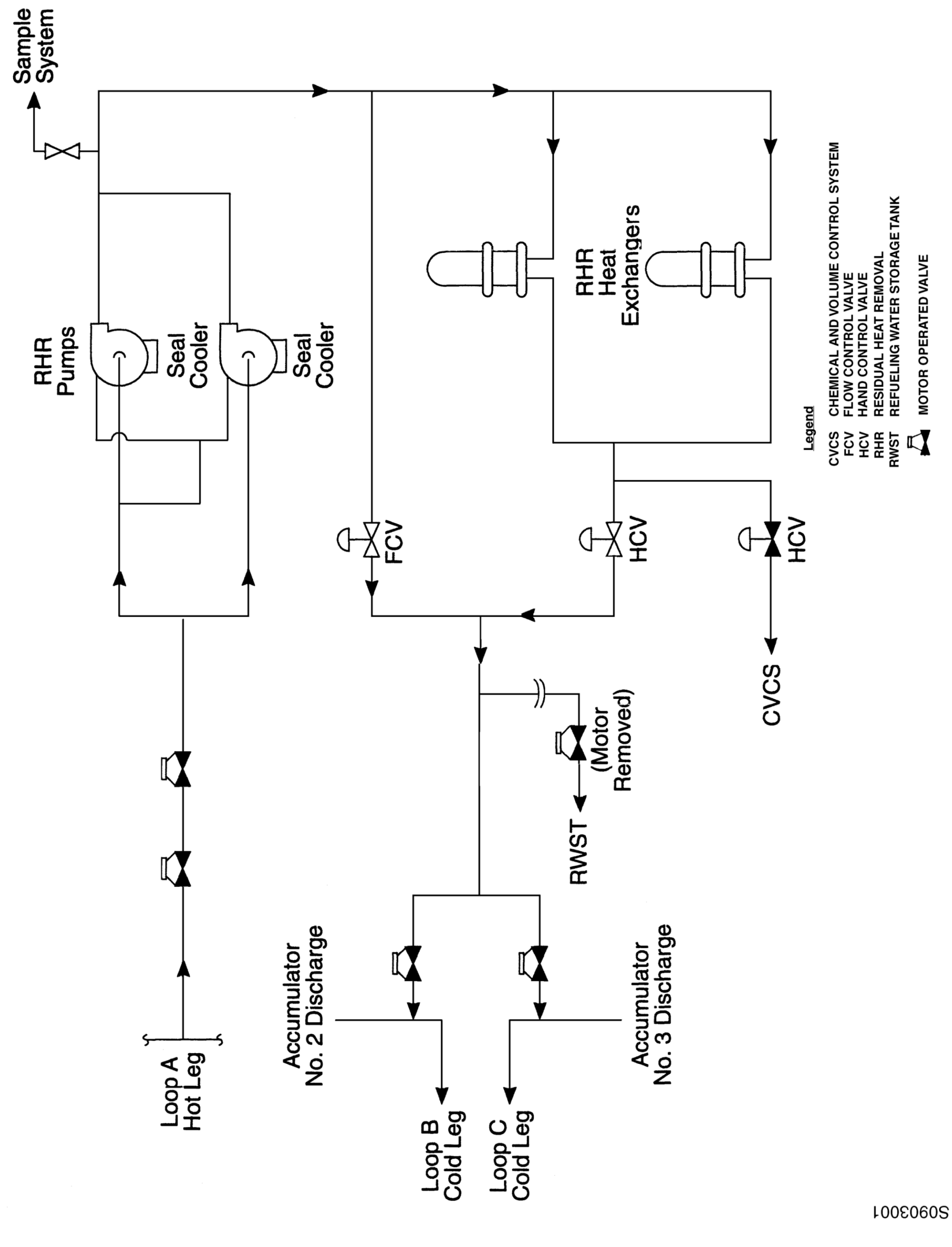
b. Expected value. Determined by the concentration of boric acid and alkali present.

c. Limit not applicable with $T_{avg} \leq 250°F$.

Table 9.3-4
RESIDUAL HEAT REMOVAL LOOP MALFUNCTION ANALYSIS

Component	Malfunction	Comments and Consequences
Residual heat removal pump	Rupture of casing	The casing and shell are designed for 600 psig and 400°F. The pump is protected from overpressurization by a relief valve in the piping discharging to the pressurizer relief tank. The pump can be inspected, and is located in the containment structure with protection against missiles. Rupture is not considered credible.
Residual heat removal pump	Pump fails to start	One operating pump furnishes enough flow to meet the required cooldown rate.
Residual heat removal pump	Manual valve on pump suction is closed	This is prevented by administrative controls during pre-startup and operational check.
Residual heat removal pump	Stop valve in discharge line closed or check valve sticks closed	Pre-startup and operational checks confirm position of valves.
Remote operated valve inside containment in pump suction line	Valve fails to open	Valve position indication light indicates that the valve has not opened. Valve is opened manually or unit is slowly cooled by feed and bleed procedures.
Motor-operated valve inside containment in system discharge line	Valve fails to open	Two valves in parallel. If one fails to open, flow passes through other valve.
Residual heat exchanger	Tube or shell rupture	Rupture is considered very unlikely because of low operating pressure as compared to design pressure. In any event, the faulty heat exchanger can be isolated and the remaining heat exchanger used for cooldown.
Valve in bypass line around residual heat exchangers	Valve sticks open	Part of flow does not pass through residual heat exchangers increases the time for unit cooldown.

Figure 9.3-1
RESIDUAL HEAT REMOVAL SYSTEM



9.4 COMPONENT COOLING SYSTEMS

The component cooling systems consist of the following:

1. Component cooling water system.
2. Chilled component cooling water system.
3. Chilled water system.
4. Neutron shield tank cooling water system.
5. Charging pump cooling water system.

These systems are used separately or in combination to supply cooling water for heat removal from various station components. The component cooling systems are shown on Figures 9.4-1 through 9.4-5 and Reference Drawings 1 through 9. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the component cooling system was found to be adequate.

9.4.1 Design Bases

9.4.1.1 Component Cooling Water System

A common supply of component cooling water serves both units to:

1. Provide cooling water to remove residual and sensible heat from the reactor coolant system during unit shutdown and cooldown.
2. Cool spent-fuel pool water.
3. Cool reactor coolant pump motor coolers.
4. Cool letdown flow in the chemical and volume control system during power operation.
5. Cool reactor coolant pump seal-water return flow.
6. Supply makeup water to the neutron shield tank cooling water system.
7. Supply makeup water to the charging pump cooling water system.
8. Provide the cooling water supply to the neutron shield tank coolers and the containment recirculation air coolers (Section 5.3.1.3.1).
9. Provide cooling water to dissipate waste heat from other reactor and station components.

The component cooling water system is an intermediate cooling system that transfers heat from heat exchangers containing reactor coolant or other radioactive liquids to the service water system (Section 9.9). The maximum heat load occurs during the initial stages of residual heat removal during a reactor unit cooldown. The component cooling water system is designed to reduce the temperature of the reactor coolant to 140°F based on a river water temperature of 100°F.

During normal full-power operation, one component cooling pump and one component cooling heat exchanger can accommodate the heat removal loads for each reactor unit. Operation of two pumps and two heat exchangers is the standard procedure during the removal of residual and sensible heat during unit cooldown, although one pump and one exchanger may be safely used under these conditions.

Operation of the component cooling water (CCW) system is required in the event of a hurricane for the removal of decay heat to attain and maintain long-term safe shutdown. The operation of the CCW system during a design basis hurricane is discussed in Section 2.3.1.2.2. and 9.9.1.3.

Each of the four component cooling heat exchangers is designed to remove the entire heat load from one unit plus half of the heat load common to both units during normal operation. Each heat exchanger is also capable of removing half of the heat load occurring four hours after a shutdown of one unit under conditions representing the maximum allowable cooldown rate.

The Vacuum Priming System ties into each component cooling heat exchanger at the top of the inlet and outlet channel heads, which are the high points of the portion of the service water that supplies the heat exchangers. The Vacuum Priming System is utilized to initiate the siphon action when placing the heat exchangers in service. The design of the component cooling heat exchanger service water piping system does not require that the Vacuum Priming System remain in service for the heat exchanger to be operable. To protect against a break in the vacuum priming lines and subsequent loss of service water flow, design changes were implemented to add a check valve in the vacuum priming line and provide separate float valves for the inlet and outlet channel heads. The portion of the vacuum priming line between the check valve and the channel heads of each heat exchanger is safety-related.

The presence of excess radioactivity in the component cooling water system is detected by two gamma scintillation radiation monitors. High-radiation signals from either of these detectors cause the surge tank vent isolation valve to shut and initiate an alarm in the control room. One detector monitors the supply to Unit 1 and is mounted on the 18-inch combined-discharge line from component cooling heat exchangers 1-CC-E-1A and 1B. The second detector monitors the supply to Unit 2, and is mounted on the 18-inch combined-discharge line from component cooling heat exchangers 1-CC-E-1C and 1D. Both detectors are located in the Unit 1 turbine building to prevent possible interference from background radiation levels in the auxiliary building. Operation of these detectors is described in Section 11.3.3.

Component design data for the component cooling water system are given in Table 9.4-1. A more detailed system description is given in Section 9.4.3.1.

Portions of the component cooling water system are designed as Class I (Section 15.2.1).

9.4.1.2 **Chilled Component Cooling Water System**

The chilled component cooling water system circulates chilled component cooling water to selected components for cooling when normal temperature limits cannot be maintained by the component cooling system. A more detailed system description is given in Section 9.4.3.2.

The chilled component cooling water system can be used to supply water to the following components:

1. Containment recirculation air coolers.
2. Neutron shield tank coolers.
3. Primary drain tank vent chiller condenser (Unit 1 chilled component cooling water system only).
4. Recombiner aftercooler (Unit 1 chilled component cooling water system only).
5. Steam generator recirculation coolers.

Three chilled component coolers and three chilled component cooling pumps are provided for the chilled component cooling water subsystem that serves both units. A pump and cooler serves each unit and one pump and cooler is provided for use as a spare. The piping is arranged so that the spare cooler and pump can be used together for either unit or individually to replace a component normally used for either unit.

Chilled component cooling water system component design data are given in Table 9.4-10.

9.4.1.3 **Chilled Water System**

Chilled water is provided separately for each unit. Each 400-ton capacity chilled water system is designed to supply 1260 gpm of 40°F chilled water.

The chilled water system provides cooling to the chilled component cooling heat exchangers.

Chilled water is also used directly to cool the water in the refueling water storage tank to nominal 45°F after a refueling operation.

Chilled water system component design data are given in Table 9.4-2. Additional system data are given in Tables 9.4-3 through 9.4-5. A more detailed system description is given in Section 9.4.3.3.

9.4.1.4 **Neutron Shield Tank Cooling Water System**

The neutron shield tank cooling water system is designed to circulate and cool the water in the neutron shield tank, which is heated by neutron and gamma radiation.

Two neutron shield tank coolers, a neutron shield surge tank, a corrosion control tank, and all necessary piping and valves comprise the system serving each reactor unit. Each neutron shield tank cooler has 100% capacity. The second cooler is a spare that can be placed in operation remotely by means of motor-operated valves.

Neutron shield tank cooling system component design data are given in Table 9.4-6. A more detailed system description is given in Section 9.4.3.4.

9.4.1.5 **Charging Pump Cooling Water System**

The charging pump cooling water system consists of two separate subsystems: a component cooling water subsystem and a service water subsystem. The charging pump service water system is described in Section 9.9.2.1.

A separate charging pump cooling water system is provided for each reactor unit.

The charging pump component cooling water system is designed to transfer heat from the charging pump mechanical seal coolers to the intermediate seal coolers.

Charging pump component cooling water system component design data are given in Table 9.4-7. A more detailed system description is given in Section 9.4.3.5.

The charging pump component cooling water system is designed as Class I (Section 15.2.1).

9.4.2 Piping and Valves (Check Valves and Manually Operated Gate, Butterfly, and Globe Valves)

Carbon steel pipe is used throughout the system. Joints are welded, except where flanges are used at connections to equipment and to butterfly and check valves in sizes 10-inch and larger. All valves are of steel material except certain butterfly valves, which are cast iron. Selected piping, valves, and supports are designed as Class 2. Expansion joints are provided at the suction and discharge of the component cooling water pumps. The piping system conforms to the requirements of the USA Code for Pressure Piping B-31.1.

Small thermal relief valves are constructed with stainless steel body and trim and carbon steel bonnet and cap. Larger relief valves have carbon steel bodies with stainless steel trim.

9.4.3 System Descriptions

9.4.3.1 **Component Cooling Water System Description**

During operation, component cooling water is pumped through the shell side of the component cooling water heat exchangers, where it is cooled by service (river) water (Section 9.9), and then through parallel circuits that can cool the following components:

1. Reactor coolant pump thermal barriers, bearing oil coolers, and motor stators.

2. Excess letdown heat exchangers (intermittent heat load).
3. Nonregenerative heat exchangers.
4. Various primary and steam generator blowdown sample coolers (intermittent heat load).
5. Seal-water heat exchangers.
6. Residual heat removal pumps seal coolers (during the second phase of unit cooldown, Section 9.3.1).
7. Residual heat removal exchangers (during the second phase of unit cooldown, Section 9.3.1).
8. Boron recovery system equipment (intermittent heat load).
9. Containment penetration cooling coils.
10. Fuel pool coolers.
11. Reactor shroud cooling coils.
12. Primary shield penetration cooling coils.
13. Primary shield water wall coolers.
14. Primary drain coolers.
15. Liquid waste disposal system equipment (abandoned in place, with the exception of the contaminated drain tank pump cooler).
16. Gaseous waste disposal system equipment.
17. Neutron shield tank coolers.
18. Reactor containment recirculation air coolers.
19. Containment instrument air compressor heat exchangers.

The component cooling water system is designed as a closed system, with a surge tank at the pump suctions. The tank is the high point of the system and provides the required net positive suction head for proper operation of the pumps. The heat exchangers are located in the turbine building for Unit 1. Pumps, tanks, and some of the equipment cooled by the system are installed in the auxiliary building; the fuel pool coolers are in the fuel building, the containment instrument air compressors are in safeguards, and the steam generator blowdown sample coolers are in the turbine building; the remainder of the equipment served is located in the reactor containments. Two 18-inch main supply and two 18-inch main return lines are used for each reactor unit. These mains, in full size, are connected directly to the residual heat removal exchangers, located in the reactor containments at the extremities of the two piping loops. Reduced size branches connected to the mains form cross-circuits that serve the remainder of the apparatus being cooled. The majority of equipment common to both reactor units is located in the auxiliary building; the fuel pool coolers are in the fuel building. Associated cross-circuits are double connected to the mains for both reactor units. High-point vents and low-point drains are provided as required by the piping configuration.

Each cooling water outlet line from a piece of equipment contains a valve for controlling flow; the valve is either a manually operated globe type or an automatic air-operated type positioned by pressure or temperature control signals originating in cooled systems.

The system is provided with trip valves for isolating the containment structures in accordance with the requirements of the containment isolation system (Section 5.2).

The RHR heat exchanger component cooling water trip valves are equipped with quick-disconnect instrument air fittings to provide a method to locally operate the valves with a portable air source. The operation of these valves is required for decay heat removal during plant cooldown, following a postulated fire in accordance with the requirements of Appendix R to 10 CFR 50.

The system is monitored from the control room by indicators that display the following data (data of a common nature are displayed on both control boards):

1. Component cooling pump discharge pressure.
2. Radioactivity, temperature, and flow in the supply mains immediately downstream from the component cooling water heat exchangers.
3. Temperature and flow in the residual heat removal heat exchanger return mains at the exits from the reactor containments.
4. Temperature in the return mains at the component cooling pump suctions.
5. Level in the component cooling surge tank.

Pressure switches for automatic starting of standby pumps are installed in the component cooling pump discharge mains. Local indicators for pressure, temperature, level, and flow are provided on a general basis. Selected temperatures are sensed and output signals are fed into the computer monitoring system (Section 7.8), thus providing full- time scanning and alarming. These temperatures can be read out during periods of abnormal values. Other important temperatures, pressures, levels, and flows are alarmed in the control room when abnormal values are reached.

The component cooling water pumps are normally controlled from the control room. In the event of a control room evacuation, pumps can be operated at the switchgear in the emergency switchgear room. See Section 7.7.2 for discussion on compliance with 10 CFR 50 Appendix R.

Thermal relief valves are installed around equipment with a significant potential for overpressurization by a combination of closed component cooling water inlet and outlet valves and heat input from the isolated equipment. The overhead gas compressor, boron evaporator distillate pump, primary drain tank pump, waste gas compressor, residual heat removal pump seal cooler, and containment penetration coolers (inner and outer), are examples of equipment not requiring thermal relief protection, since their overpressurization potential is insignificant. A relief valve and a vacuum breaker valve are provided for the component cooling surge tank. Also, a relief valve is installed on the line supplying makeup to the component cooling surge tank.

The surge tank level is maintained at a level sufficient to accommodate minor system surges and thermal swell due to cooldown operation without overflowing through the relief valve. The makeup line is double connected to both main condensate systems and a tie-in from the bearing cooling makeup pump; this provides redundancy, since it is unlikely that both turbine generators and bearing cooling makeup would be out of service during cooldown of a reactor unit. High level in the tank is lowered by manual operation of system low-point drains. The tank is equipped with a full-length gauge glass.

A 120-gallon-capacity chemical addition tank is connected to the component cooling pump suction and discharge piping. When utilized, the tank is charged with chemicals after being isolated and having its level lowered by manual valves. After closure of the charging and manual level valves and opening of the isolation valves, discharge pressure forces water into the tank and injects the mixture into the system at the pump suctions. Chemicals can also be added using a portable chemical addition pump.

The desired water chemistry is obtained by the addition of potassium chromate for corrosion inhibition with potassium hydroxide and potassium dichromate being added for pH control as needed. The design objective of the chemical treatment is to initially treat the system with a maximum of 500 ppm of chromate with control being maintained between 150-500 ppm of chromate at a pH of 8.0 to 9.5. Control within these parameters may be adjusted according to industry good practices. The 500 ppm maximum chromate limit applies only to subsystems that contain carbon-based mechanical seals. Sampling is performed at the central station in the auxiliary building. Several local sample points are also provided.

9.4.3.2 **Chilled Component Cooling Water System Description**

The chilled component cooling water system can be used to supply water to the following components when the component cooling water system cannot be maintained within normal limits:

1. Containment recirculation air coolers.
2. Neutron shield tank coolers.
3. Primary drain tank vent chiller condenser (Unit 1 chilled component cooling water system only).
4. Recombiner aftercooler (Unit 1 chilled component cooling water system only).
5. Steam generator recirculation coolers.

Typically, the chilled component cooling system is placed in service when the component cooling system supply temperature can no longer be maintained within normal limits. This condition is usually encountered during summer months when river water temperature is high. The heat from the various system loads is transferred to the chilled water system.

The major components associated with the system are three pumps and three heat exchangers. Makeup water and a surge volume for the system are provided by the component cooling system.

The three chilled component cooling pumps are single-stage, centrifugal pumps. They provide the motive force to circulate chilled component cooling water through the system. When this system is in operation, normally two chilled component cooling pumps are running (one for each unit) and the third pump is used as a spare. The spare pump can be used to supply either Unit 1 or 2. The chilled component cooling pumps are controlled from the main control room.

Three chilled component coolers (heat exchangers) are used to transfer the heat from the chilled component cooling system to the chilled water system. Each cooler consists of a horizontally mounted shell, which encloses tubes, and tubesheets. One heat exchanger is provided for each reactor unit, and one is maintained as a spare but can serve either unit. The discharge of the chilled component cooling pump is directed through the shell of the heat exchanger, where heat is rejected to chilled water flowing through the heat exchanger tubes.

9.4.3.3 **Chilled Water System Description**

Each unit has an independent, closed-loop chilled water system. A third full-size spare chiller unit is provided with cross-tie chilled water piping to permit use by either unit. Manual valves are provided for component isolation and for cross-connections.

Each of the closed-loop systems consists of:

1. Full-sized chilled water circulation pumps (three for Unit 1, two for Unit 2).
2. A packaged centrifugal liquid chiller using refrigerant R22 for the vapor compression cycle, with a rotary compressor and motor, oil coolers, purge unit, pre-wired internal controls, indication, and a condenser section.
3. A surge tank with automatic level control and makeup from alternate condensate system sources.
4. Isolation and control valves.
5. Fluid systems and electrical component protection.
6. Necessary instrumentation and controls for local control.

The Unit 1 chiller and swing chiller are located on a platform at Elevation 35 feet in the northeast sector of the Unit 1 turbine building. Piping and valves are provided so that one chilled water pump is normally aligned with each chiller unit, with the third pump serving as backup to either loop. Two surge tanks are provided on the north wall of the Unit 1 operating floor.

The Unit 2 chiller and two full-sized chilled water pumps are located on Elevation 9 ft. 6 in. in the northeast sector of the Unit 2 turbine building. A surge tank for the system is located on the north wall of the Unit 2 turbine building operating floor.

Each chiller uses a rotary compressor, driven by a 468 hp, 4000V, drip-proof motor. Cooling is supplied to the chilled component cooling heat exchangers (Section 9.4.3.2).

For the normal operation of the system, a chilled water pump is started to establish the flow, and the pump minimum flow path is established to a surge tank that maintains constant pressure at the pump suction and provides an area for chemical addition.

Local flow indication as well as low-flow cutoff of the chiller, is provided for chilled water and bearing cooling (BC) water flow. Capacity control is achieved by use of a slide valve which provides fully modulating capacity control from 100% to 10% of full-load. The minimum inlet cooling water temperature to the chiller condensers is 63°F. The supply BC water is normally maintained in a range of 65°F to 95°F by throttling the service water flow to the BC heat exchangers. The BC temperature is monitored and controlled by a station procedure.

Table 9.4-2 lists design conditions for the chilled water units.

Three 100%-capacity, horizontal centrifugal chilled water circulation pumps are provided in Unit 1:

1. One for the Unit 1 chiller.
2. One for the swing chiller.
3. One spare pump as backup to supply either chiller.

Two 100%-capacity, horizontal centrifugal chilled water pumps are provided in Unit 2.

A chilled water circulation pump is manually aligned and started to recirculate water through the chiller and service components.

See Table 9.4-3 for a more detailed description of the chilled water circulation pumps.

The design conditions of the surge tanks are provided in Table 9.4-4.

The chilled water system comprises 150-lb rated carbon steel pipe and valves to meet the existing chilled water system requirements (see Table 9.4-5 for a listing of piping and valve data).

Control of the chilled water system is maintained from local control panels. Important parameters are monitored on the panels, with alarms provided in the control room.

The Chilled Component Cooling Water System has the capability to monitor the following:

1. Flow and temperature measurements at the inlet to the reactor containment air recirculation coolers.
2. Temperature measurement at the outlet of the reactor containment air recirculation coolers.

9.4.3.4 Neutron Shield Tank Cooling Water System Description

A neutron shield tank cooling system is provided for each reactor unit to cool the water in the neutron shield tank, which is heated by neutron and gamma radiation from the reactor. The heated water in the neutron shield tank rises by natural convection to the top of the tank and into the pipe connected to the neutron shield tank cooler. The cool water from the component cooling water system or the chilled water system is circulated through the neutron shield tank cooler, cooling the heated neutron shield tank water. Only one neutron shield tank cooler is required to perform the required cooling; the other cooler is a spare and is isolated from the system by motor-operated valves. A surge tank accommodates thermal expansion of the neutron shield water. A level sensor on the surge tank sends a signal to the control room to indicate low system level. A solenoid-operated valve is actuated from the control room to replenish the system from the component cooling water system. The corrosion control tank is used for the manual addition of a corrosion inhibitor when the reactor is not operating.

9.4.3.5 Charging Pump Component Cooling Water System Description

A charging pump cooling water system for each reactor unit provides component cooling water for the charging pump mechanical seal heat exchangers, which cool the water circulating in the charging pump mechanical seal cooling loops.

Either of two 100%-capacity cooling water pumps circulates the component cooling water in the system. A surge tank accommodates thermal expansion of the component cooling water. A level sensor in the charging pump seal cooling surge tank automatically actuates a makeup valve to replenish the subsystem from the component cooling water system. The pH of the charging pump component cooling system is maintained between 8.0 and 10.5. To ensure that component cooling water is continually available to the mechanical seal coolers, one pump is in operation and the other pump is in standby. The standby pump is automatically actuated on low pump discharge pressure to supply cooling water in the event of failure of the operating pump. Two 100%-capacity charging pump intermediate seal coolers are provided to cool the component cooling water that is circulated to the mechanical seal coolers.

The installation of two full-capacity charging pump component cooling water pumps and two full-capacity charging pump intermediate seal coolers provides 100% redundancy for this component cooling water system. All components of the charging pump component cooling water system, including pumps, heat exchangers, and tanks are designed to Seismic Class I criteria.

The charging pump component cooling water pumps are connected to the emergency electrical bus to ensure that they will operate in the event of a loss of station power.

Regulatory Guide 1.97 requirements for post-accident monitoring of component cooling water system status are satisfied by flow and temperature measurement at the discharge of each charging pump component cooling water pump. Flow and temperature transmitters are environmentally and seismically qualified in accordance with IEEE 323-1974 and IEEE 344-1975 respectively. Control room display is provided through the NUREG 0696 multiplexing system.

9.4.4 Design Evaluation

9.4.4.1 **Component Cooling Water System Availability and Reliability**

The component cooling water system uses machinery and equipment of conventional and proven design. All components are specified to provide maximum economy, safety, and reliability.

The installation of four pumps and four heat exchangers for two reactor units provides 100% backup during normal operation of the two units. During cooldown of one reactor unit, there is 100% backup for it if the other unit is out of service, and 50% backup if the other unit is in normal operation. If only one pump is available for cooldown of a reactor unit, the cooldown time is extended without equipment damage or hazard to the public or operating personnel. Seismic Class I spray barriers protect the component cooling pump motors from water due to operation of fire protection equipment or other causes.

Most of the piping, valves, and instrumentation in the reactor containment are located outside the reactor primary shield wall and above the post-accident water level in the bottom of the containment. The exceptions are the lines for the neutron shield tank coolers and the primary shield penetration and water wall cooling coils; these lines can be secured by valves located outside of the primary shield wall. The equipment in the containment is protected against credible missiles and flooding during post-accident operations. Also, shielding is provided to allow limited maintenance and inspection during power operation.

Equipment not located in the containment may be inspected and maintained during power operation.

Portions of the system are of Class I design and designed to the codes stated in Section 9.4.1. The main piping loops and the loop for the fuel pool coolers are analyzed and designed to meet associated thermal stress requirements.

The following components are located inside the containment: the excess letdown heat exchanger, reactor coolant pump thermal barrier, oil coolers and motor stators, primary shield penetration and water wall coolers, neutron shield tank coolers, reactor shroud cooling coils, primary drain coolers, residual heat removal heat exchangers, containment air recirculation coolers, residual heat removal pump seal coolers, and pipe penetration cooling coils. Isolation of flow from the component cooling water system to the containment is described in Section 5.2.

The component cooling surge tank, which normally operates at atmospheric pressure, is equipped with a vent line connected into the process vent system. The tank vent line contains an automatic shutoff valve; this valve, normally open, closes automatically upon receiving a high-radiation signal from either of the two radiation monitors located on the discharge piping from the component cooling water heat exchangers, and can be manually closed from the control room. The high-radiation condition that caused the valve closure is indicated by an alarm.

An air-operated trip valve is installed in the outlet cooling water header from the reactor coolant pump thermal barriers, in the outlet cooling water line from the excess letdown heat exchanger, and in the outlet cooling water line from the primary drain cooler. A check valve is installed in the inlet cooling water header to the bearing oil coolers, stator coolers, and in the inlet cooling water line to the excess letdown heat exchanger. Two check valves are installed in the inlet cooling water line to the thermal barriers. In the event that a leak occurs in the thermal barrier cooling coil, an alarm annunciates in the control room and the high-pressure reactor coolant is safely contained by closing the appropriate stop valve. A high cooling water outlet flow signal from either the thermal barrier cooling header or the excess letdown heat exchanger automatically closes the associated isolation valves. The air-operated stop valves in the outlet cooling water header from the thermal barriers and in the reactor containment recirculation air cooler outlet lines leaving the reactor containment close on a high-high containment pressure signal. The main cooling water lines from the residual heat removal heat exchangers leaving the reactor containment close on a safety injection signal.

9.4.4.2 **Component Cooling Water System Leakage Provisions**

The component cooling water heat exchangers are located in the turbine building. Provisions are made to preclude the possible spread of radioactive contamination. These precautions include isolation of each heat exchanger by manual shutoff of the inlet and outlet component cooling water valves, treatment of any leakage and water samples from these heat exchangers as radioactive, and installation of the heat exchangers within a curbed area to preclude radioactive contamination of the turbine building floor. Any leakage is then returned to the liquid waste disposal system (Section 11.2.3) via the sump pump which services the curbed area. The component cooling heat exchanger curbed area consists of a trough covered by grating surrounding the heat exchangers to direct any leakage to the sump pump. Welded construction is used almost exclusively throughout the system to minimize possibility of leakage from pipes, valves, and fittings.

Small leakage inside the containment is not considered to be objectionable. Contamination could result from the following: side-to-side leakage in a heat exchanger in the chemical and volume control, residual heat removal, or sampling systems, or a leak in the thermal barrier of a reactor coolant pump. Leakage from the system is primarily detected by falling surge tank level. Temperature, level, and flow indicators in the control room may be used to detect leakage at certain points. Elsewhere, leaks can be located by inspection or isolation.

9.4.4.3 **Incident Control**

The piping mains have the following valves at the containment walls: shutoff valves outside containment and check valves inside containment in supply lines; trip and shutoff valves outside containment in return lines. The trip valves close upon receiving the containment isolation signal from safety injection. Piping for the reactor coolant pumps, reactor shroud cooling coils, and containment recirculation air coolers is valved in an identical manner; however, the valves close on a high-high containment pressure signal (Section 5.2.2).

A backup air bottle supply is provided to ensure the RHR component cooling outside containment isolation trip valves will fail closed in the event of a loss of primary air supply. The RCP thermal barrier component cooling inside and outside containment isolation trip valves have an air lockup valve which will maintain air pressure to hold the trip valve open on a loss of normal air supply, but will not prevent the trip valve from closing on a loss of air to the actuator or on any valid close signal.

During periods of warmer river water, chilled component cooling water supplies the cooling water to the reactor containment recirculation air coolers. The transfer, or supply and return between the two systems, is accomplished by the use of air-operated flow-diverting valves. These valves are operated remote manually by means of a switch mounted on the ventilation panel in the control room. In warmer weather, the containment air coolers remain on chilled component cooling water supply unless a minor incident occurs.

9.4.4.4 **Component Cooling Makeup Water**

Makeup for the component cooling water system is provided from the discharge of the main condensate pumps, which draw on the condenser hotwell. Operation of engineered safety features will not be affected by loss of makeup water to the component cooling water system if offsite power is lost, since the component cooling water system is not required for operation of engineered safety features.

During normal prolonged outages of both units (with station power available), a separate makeup pump supplies makeup water to the closed-loop component cooling and bearing cooling systems.

To maintain component cooling water to the fuel pool cooling system (Section 9.5), a component cooling water pump can also be operated from the emergency electrical bus during a complete loss of offsite power. The component cooling water system is closed, and leakage from this system will be at a very slow rate. In addition, the component cooling water surge tank is a source of reserve water, which must be exhausted before makeup to the component cooling water system is required. If the component cooling water system requires makeup before offsite power is restored, a portable pump can be connected to supply makeup.

9.4.4.5 Cooling Water Support for Other Systems

In the event of a single failure in the component cooling water system (e.g., at the discharge header), cooling water for the reactor coolant pumps, the excess letdown heat exchanger, the residual heat removal system, and the nonregenerative heat exchanger would be lost. The charging pumps would not be affected because they have been provided with a separate system.

In the unlikely event of a total loss of component cooling water, the operator would bring the reactor to a safe shutdown, or hot standby condition, with all reactor coolant pumps tripped and letdown flow discontinued, but with charging pumps operating to supply seal-water injection flow to the reactor coolant pump seals. This condition can be maintained until the pressurizer has been filled by the injected seal-water, thereby providing time for restoration of component cooling water.

Boron adjustments may be made, if required, by shifting the charging pumps' suction to the refueling water storage tank. Additional adjustments can be made by aligning the boric acid storage tanks directly to the suction of the charging pumps, thereby introducing concentrated boric acid to the reactor coolant system through the seal-water injection flow to the reactor coolant pump seals.

The charging pump component cooling water system cannot be totally disabled by a single passive failure. The system has been designed with cross-connect piping and sufficient valves so that any single passive failure can be isolated, which will allow the system to continue to operate and provide cooling water to at least two charging pumps (Reference Drawing 9).

The isolation of a single passive failure and arrangement of the operable portion of the system to continue to provide the cooling water must be performed manually by the plant operators. In addition, the standby charging pump may have to be placed in operation, since the isolation of the single passive failure might prevent cooling water from reaching the operating charging pumps. The complete system is expected to be accessible during an accident; however, if the course of an accident were to result in gross fuel failure, the local area radiological dose rates may substantially restrict auxiliary building access. For this situation, the continued operation of the charging pump component cooling water system is not essential for the proper operation of the charging pumps.

9.4.4.6 Component Cooling Water System Malfunction Analysis

A failure analysis of equipment, components, and system interconnections is presented in Tables 9.4-8 and 9.4-9.

9.4.4.7 Component Cooling Cleanup

In the event the Component Cooling Water System becomes contaminated through leakage at interface points with radioactive systems, a means for removing the contaminants and reducing radiation levels is provided. Cleanup is provided from the Chilled Component Cooling Water

Subsystem which recycles a portion of the chilled water flow through one or both of the Boron Cleanup Ion Exchangers (1-BR-I-2A & B). Once through the ion exchanger(s), the processed component cooling water is returned to the Chilled Component Cooling Water pumps' suction header. Flow through the cleanup piping is monitored and maintained by local flow indication and a manual throttling valve. All piping and valves conform to Section 9.4.2.

9.4.5 Tests and Inspections

The component cooling system is subject to the applicable inservice inspection and inservice testing requirements of the ASME Code, as required by 10 CFR 50 (Code of Federal Regulations, Title 10, Part 50). Following installation of spare parts or piping modifications, visual inspections are conducted to confirm normal operation of the system. Routine pre-startup inspections are performed, along with periodic observation during operation.

9.4.6 Minimum Operating Conditions

Minimum operating conditions for the cooling water systems, if any, are given in the Technical Specifications.

9.4 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-072A	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
	11548-FM-072A	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 2
2.	11448-FM-072B	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
	11548-FM-072B	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 2
3.	11448-FM-072C	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
	11548-FM-072C	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 2
4.	11448-FM-072D	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
	11548-FM-072D	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 2

5.	11448-FM-072E	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
6.	11448-FM-072F	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
7.	11448-FM-072G	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
8.	11448-FM-072H	Flow/Valve Operating Numbers Diagram: Component Cooling Water System, Unit 1
9.	11448-FM-071B	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 1
	11548-FM-071B	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 2

Table 9.4-1
COMPONENT COOLING WATER SYSTEM COMPONENT DESIGN DATA

I. Pumps		
Number	4 (2 required for normal operation of 2 reactor units)	
Type	Horizontal, centrifugal, single-stage	
Motor horsepower	600 hp	
Seal	Single mechanical	
Capacity	9000 gpm	
Head at rated capacity	200 ft	
Design pressure	130 psig	
Design temperature	180°F	
Materials		
Pump casing	Cast iron	
Shaft	Alloy steel, ASTM A107, Grade 1045	
Impeller	Cast iron	
II. Heat exchangers		
Number	4 (2 required for normal operation of 2 reactor units)	
Duty, each	50.3×10^6 Btu/hr	
	Shell	Tube
Design pressure	150 psig	150 psig
Design temperature	150°F	150°F
Operating pressure	95 psig	5.6 psig
Operating temperature, in/out	119.7/105.0°F	95.0/106.2°F
Material	Carbon steel	Titanium
Fluid	Component cooling water	Service water
Design code	ASME VIII, 1986	ASME VIII, 1986
III. Surge Tank	Shell	Tube
Number	1 (common to both units)	
Type	Cylindrical, horizontal	
Capacity	2810 gal	
Design pressure	40 psig	
Design temperature	150°F	
Material	Carbon steel	
Design code	ASME III, Class C	
IV. Chemical addition tank		
Number	1 (common to both units)	
Type	Cylindrical, vertical	
Capacity	120 gal	
Design pressure	150 psig	
Design temperature	150°F	
Material	Carbon steel	
Design code	ASME VIII	

Table 9.4-2
CHILLED WATER SYSTEM DESIGN CONDITIONS

Quantity	One 100% chiller for Unit 1 One 100% chiller for Unit 2 One 100% swing chiller for Unit 1 or 2
Equipment mark number	1-CD-REF-1A, 1B; 2-CD-REF-1
Type	Packaged, rotary chiller
Refrigerant, per charge	R-22, 2000 lb
Capacity	400 tons at 95°F maximum normal operating BC water and 390 tons at 105°F maximum design BC water for 52°F entering and 40°F leaving (chilled water)
Compressor voltage	4000V
Code stamping	Yes (Refrigerant side, waterside not required)
Compressor full-load input	366 kW

Table 9.4-3
CHILLED WATER CIRCULATION PUMP DATA

Manufacturer	Worthington Pump Corporation
Quantity	Three at Surry Unit 1 Two at Surry Unit 2
Type	4LR-11, horizontal centrifugal
Equipment mark number	1-CD-P-4A, B, C; 2-CD-P-4A, B
Pump design	
Flow	1320 gpm
Head (TDH)	250 ft
Operating temperature	35-60°F
Efficiency	74%
Net positive suction head available/required	58.4/20 ft
Design	124.9 bhp/125 motor hp
Speed	3600 rpm
Shaft sealing	Crane mechanical seal
Material	
Shaft	A-107-59T
Impeller	B62-52
Casing	A48-56
Design	
Pressure	175 psig
Temperature	N/A
Pump weight, total	640 lb
Motor type/motor voltage/insulation	Induction, ODP/460V/B

Table 9.4-4
CHILLED WATER SURGE TANK DATA

Manufacturer	Tower Iron Works
Quantity	Two at Surry Unit 1 One at Surry Unit 2
Equipment mark number	1-CD-TK-lA, 1B; 2-CD-TK-l
Capacity	340 gal
Operating/design pressure	0/30 psig
Operating/design temperature	40/150°F
Material	
Shell	SA-285 GRC ASME F&D, SA285 GRC
Supports	SA-36
Nozzles	SA-106 GRB
Code stamp	ASME VIII, Division 1
Dimensions	3 ft 6 in diameter x 4 ft 4 in B. L. to B. L.
Weight, empty	1300 lb
Weight, full of water	4200 lb

Table 9.4-5
CHILLED WATER SYSTEM PIPING AND VALVE DATA

Design pressure	200 psig
Design temperature	150°F
Design code	ANSI B31.1
Piping material	Carbon steel, ASTM A106, Gr. B, 1-in. type “J” insulation

Table 9.4-6
NEUTRON SHIELD TANK COOLING WATER SYSTEM COMPONENT DESIGN DATA

Neutron shield tank cooler		
Number	4 (two for each unit, one required)	
Duty, each	80,000 Btu/hr	
	Shell	Tube
Design pressure	150 psig	50 psig
Design temperature	100°F	150°F
Operating pressure	50 psig	15 psig
Operating temperature, in/out	80/85°F	125/90°F
Material	SS 316	SS 316
Fluid	Component cooling water	Shield tank water
Design code	ASME Section VIII	ASME Section VIII
Neutron shield tank surge tank		
Number	2 (one for each unit)	
Type	Cylindrical, vertical	
Capacity	1444 gal	
Design pressure	25 psig	
Design temperature	150°F	
Material	Carbon steel	
Design code	ASME VIII	
Corrosion control tank		
Number	2 (one for each unit)	
Type	Cylindrical, vertical	
Capacity	158 gal	
Design pressure	150 psig	
Design temperature	150°F	
Material	SS 304	
Design code	ASME VIII	

Table 9.4-7
CHARGING PUMP COMPONENT COOLING WATER SYSTEM
COMPONENT DESIGN DATA

Charging pump cooling water pump	
Number	2 per unit
Type	Centrifugal, in-line, single-stage
Motor horsepower	7.5 hp
Seal	Single mechanical
Capacity	90 gpm
Head at rated capacity	105 ft
Design pressure	150 psig
Design temperature	250°F
Materials	
Pump casing	Stainless Steel
Shaft	Stainless Steel
Impeller	Stainless Steel
Charging pump seal cooling surge tank	
Number	2 (1 per unit)
Type	Cylindrical horizontal
Capacity	20 gal
Design pressure	Atmospheric
Design temperature	150°F
Material	Carbon steel
Design code	ASME VIII

Table 9.4-8

CONSEQUENCES OF COMPONENT COOLING WATER SYSTEM MALFUNCTIONS

Components	Malfunction	Comments and Consequences
1. Component cooling water pumps	Pump casing ruptures	The casing is designed for 180°F temperature; design pressure is 130 psig and maximum test pressure is 200 psig. These conditions exceed those that could occur during any operating conditions. The casings are made from cast iron (ASTM A48); this metal has corrosion-erosion resistance and produces sound casings. Corrugated metal expansion joints are installed close to the pump suctions and discharges. These joints isolate the pumps from forces and moments originating in the connected piping; in addition, the pumps are designed as Class I. Pumps are missile-protected and may be inspected at any time. Rupture by missiles is not considered credible. A relief valve is installed on the line supplying makeup to the system, so that makeup source pressure cannot be applied to the casings. All units can be isolated by valves, and the standby pump can carry full load.
2. Component cooling water pumps	Original pump fails to start	Standby pump for that reactor unit can be used.
3. Component cooling water pumps	Standby pump fails to start	Standby pump for other reactor unit can be started manually in control room, after manually repositioning valves at the pumps.
4. Component cooling water pumps	Manual butterfly valve at a pump suction closed	Prevented by pre-startup and operational checks. During normal operation, each pump is checked periodically, together with its valves.
5. Component cooling water pumps	Check valve at a pump discharge sticks closed	Valve is checked periodically during normal operation.
6. Check valves in supply mains at inlet penetrations	Sticks closed	One main is flowing at all times. The valves have split disks loaded by light springs, and sticking closed is not considered credible.
7. Component cooling water heat exchangers	Tube or shell ruptures	Because of the low system operating pressure and temperature, and Class I design, rupture is considered unlikely. Each unit can be isolated and can carry full load. The standby unit intended for one reactor unit may be used for the other unit by repositioning valves. The exchangers are protected from missiles.

Table 9.4-8 (CONTINUED)
CONSEQUENCES OF COMPONENT COOLING WATER SYSTEM MALFUNCTIONS

Components	Malfunction	Comments and Consequences
8. Component cooling water heat exchanger vent or drain valve	Left open	Prevented by pre-startup and operational checks. On a unit in service, this condition would be noted by operating personnel during routine observation. On activation of a standby unit, the condition would be observed by personnel engaged in manually positioning valves at the exchanger.

Table 9.4-9
COMPONENT COOLING WATER RELIANCE ON INTERCONNECTED SYSTEMS

Interconnected System	Purpose of Interconnection	Consequences If Interconnection Is Lost
Main condensate (in turbine room)	Makeup for surge tank	The makeup line is double-connected to both main turbine generator units. A tie-in from the bearing cooling makeup pump also exists. Since it is unlikely that both units will be out of service simultaneously along with bearing cooling make-up, the source has a high degree of redundancy. If a loss of offsite power has occurred and makeup is required, a portable pump can be connected to fulfill this function.
Boron recovery	Signals to automatic control valves in component cooling water system piping	None; use of equipment is intermittent.
Sampling	Conduct sample to central sampling station	None; samples at all important points may be collected at local sampling connections in the piping.
Vent and drain	Disposal of equipment vents and piping drains	Since lines are open, without valves or other devices, loss of the interconnections is not considered credible.
Containment isolation	Signals to trip valves for isolation purposes, under accident conditions	Valves fail safe (to closed position) upon loss of signal.

Table 9.4-10
CHILLED COMPONENT COOLING WATER SYSTEM COMPONENT DESIGN DATA

Chilled Component Cooler		
Number	3 (one for each unit, one common to both units)	
Duty, each	3,600,000 Btu/hr	
	Shell	Tube
Design pressure	150 psig	150 psig
Design temperature	150°F	150°F
Operating pressure	60 psig	60 psig
Operating temperature, in/out	80/70°F	60/66°F
Materials	Carbon steel	Admiralty
Fluids	Component cooling water	Chilled water
Design code	ASME III Class C	ASME III Class C
Chilled Component Cooling Pumps		
Number	3 (one for each unit, one common to both units)	
Type	Horizontal centrifugal, single stage	
Motor horsepower	50 hp	
Seal	Mechanical	
Head at rated capacity	187.5 ft	
Design pressure	250 psig	
Design temperature	250°F	
Materials		
Pump casing	Cast iron	
Shaft	Carbon steel	
Impeller	Cast iron	

Figure 9.4-1
COMPONENT COOLING WATER SYSTEM

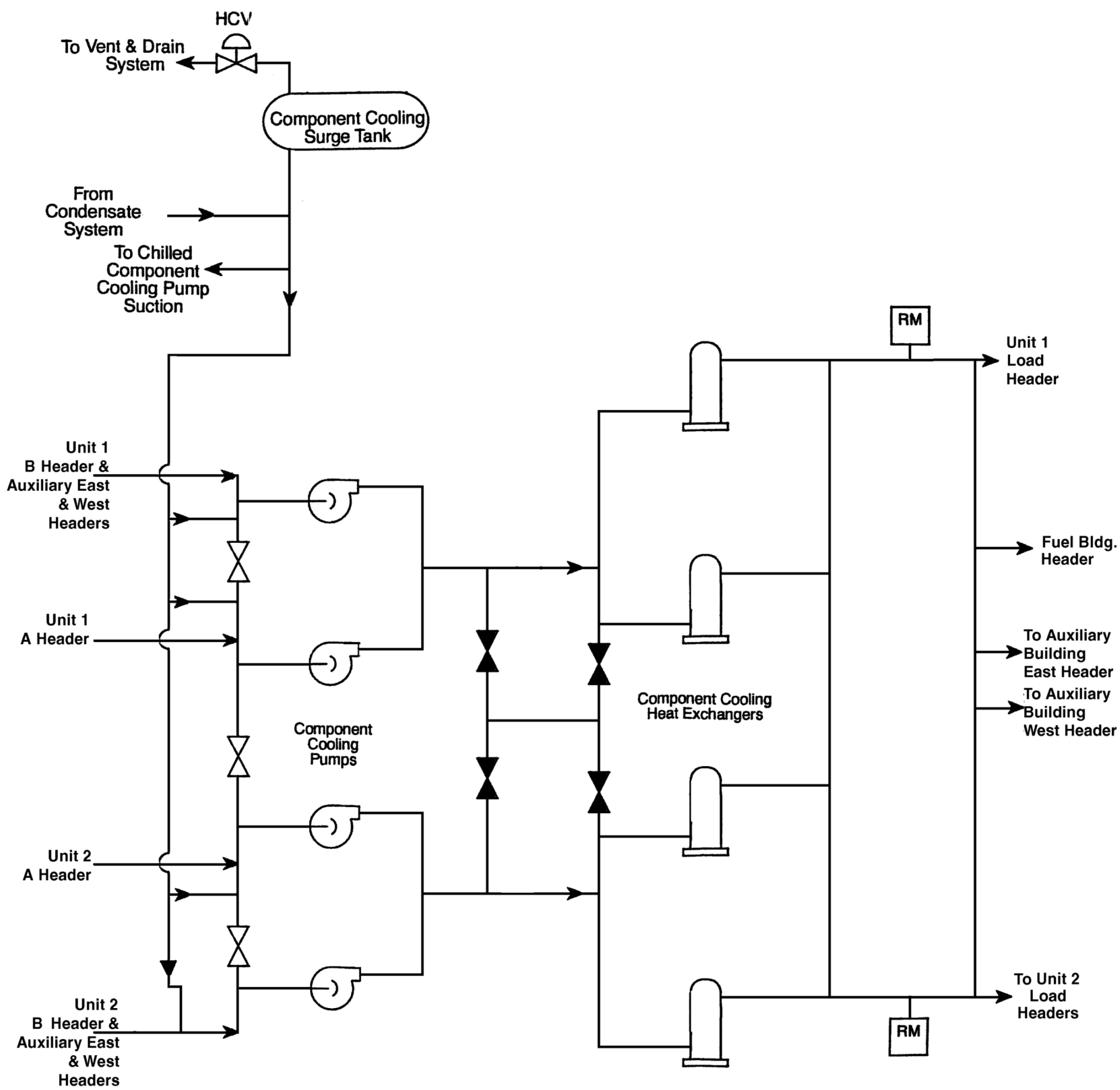


Figure 9.4-2
CHILLED COMPONENT COOLING WATER SYSTEM

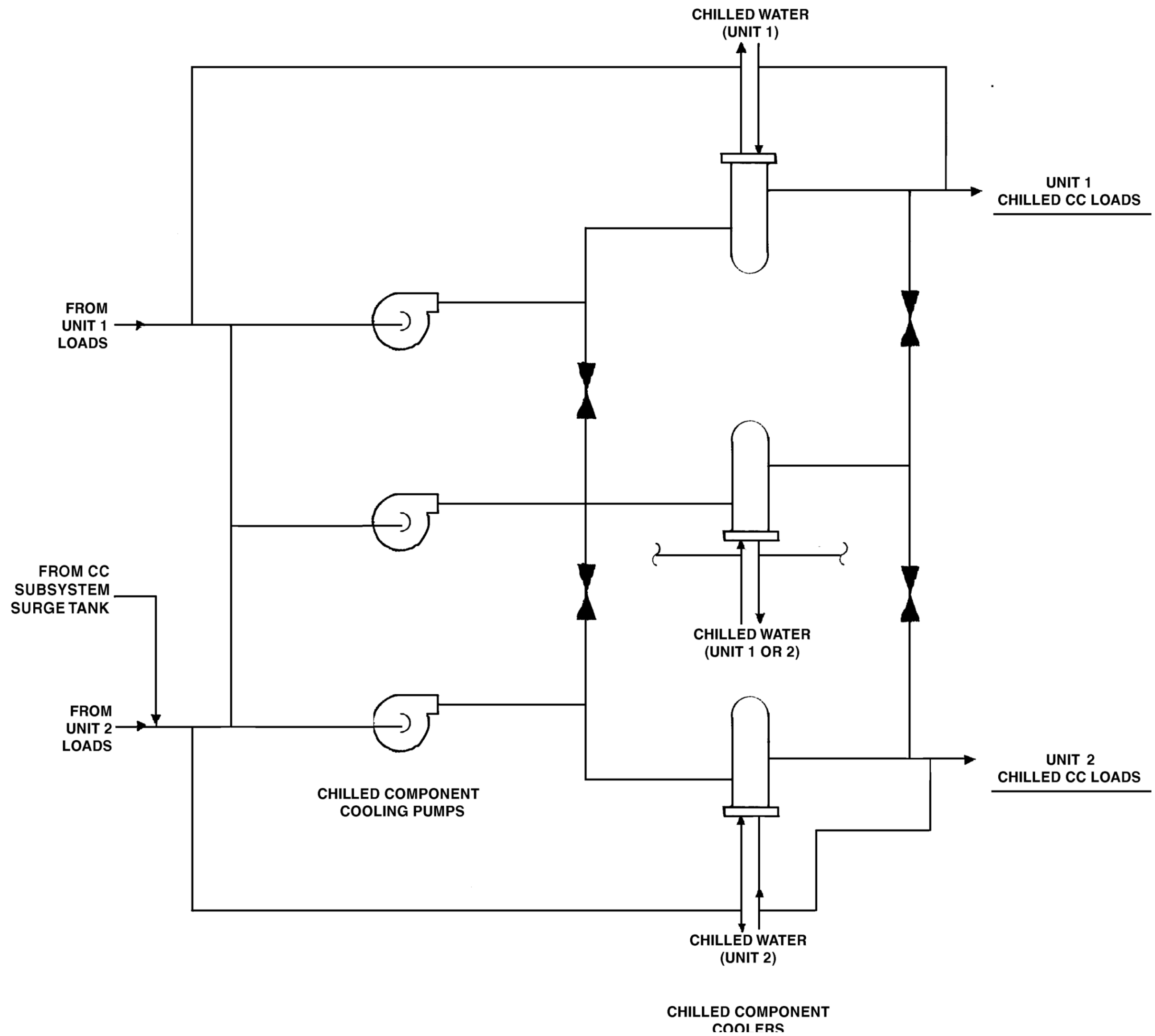


Figure 9.4-3
CHILLED WATER SYSTEM

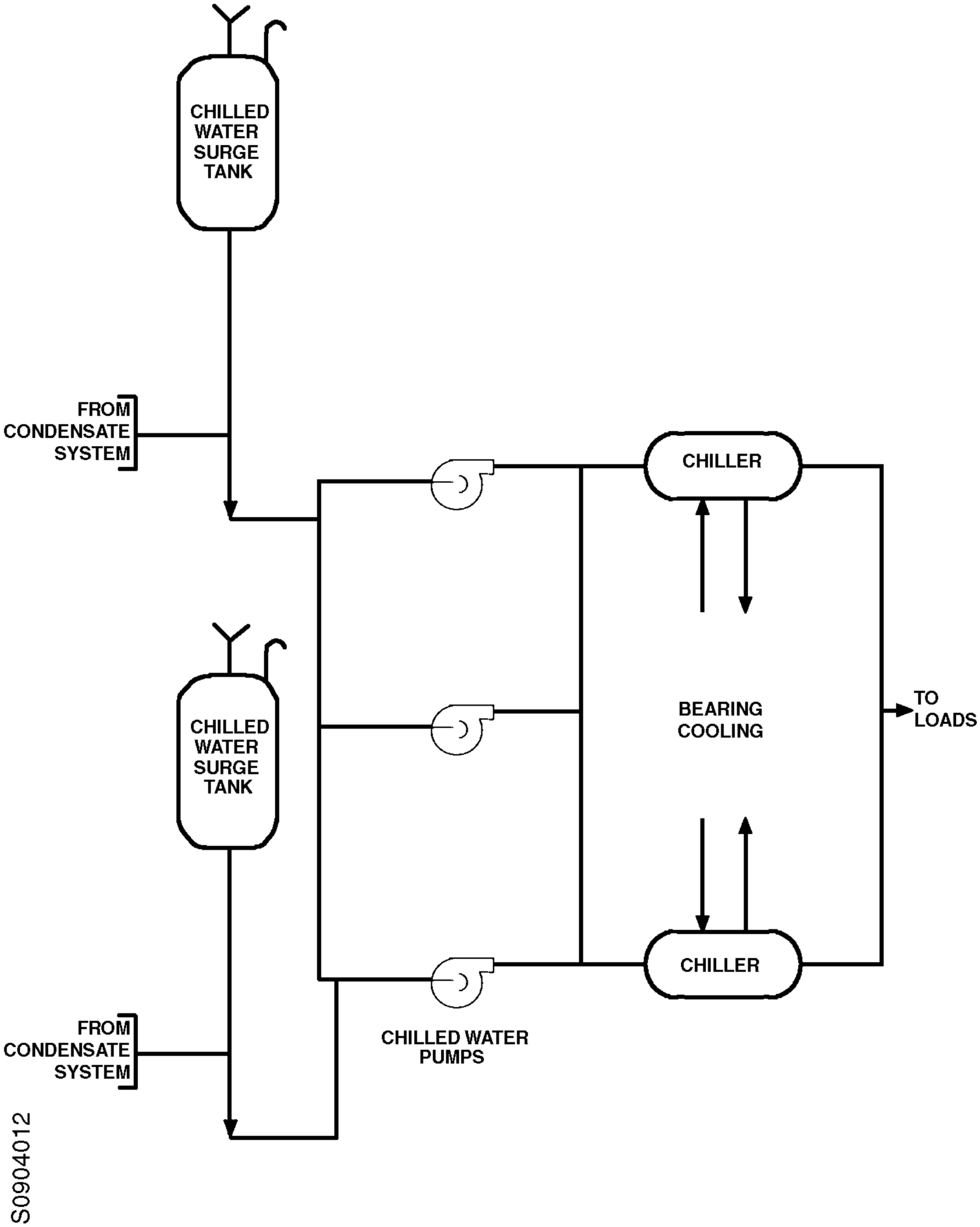


Figure 9.4-4
NEUTRON SHIELD TANK COOLING WATER SYSTEM

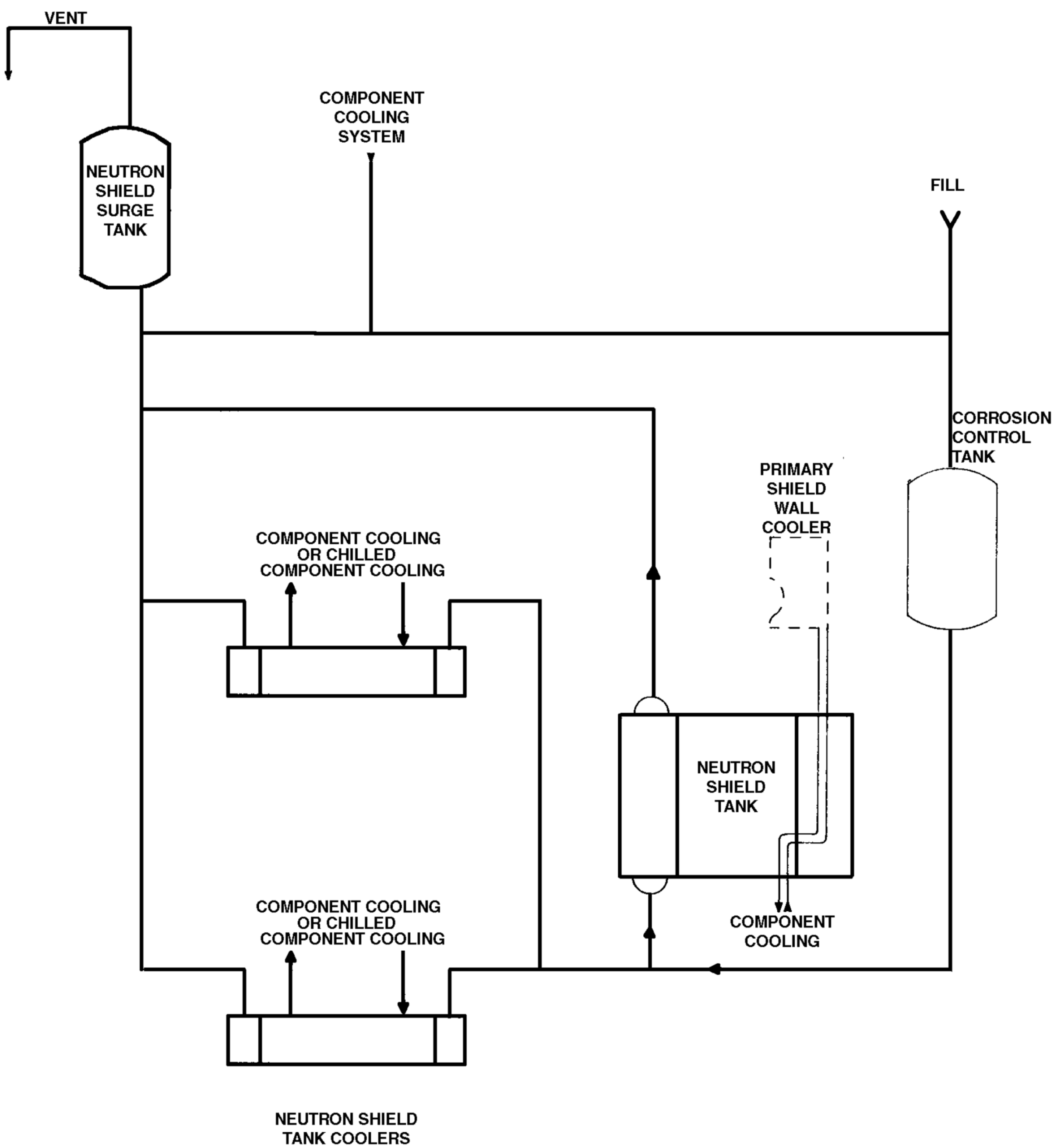
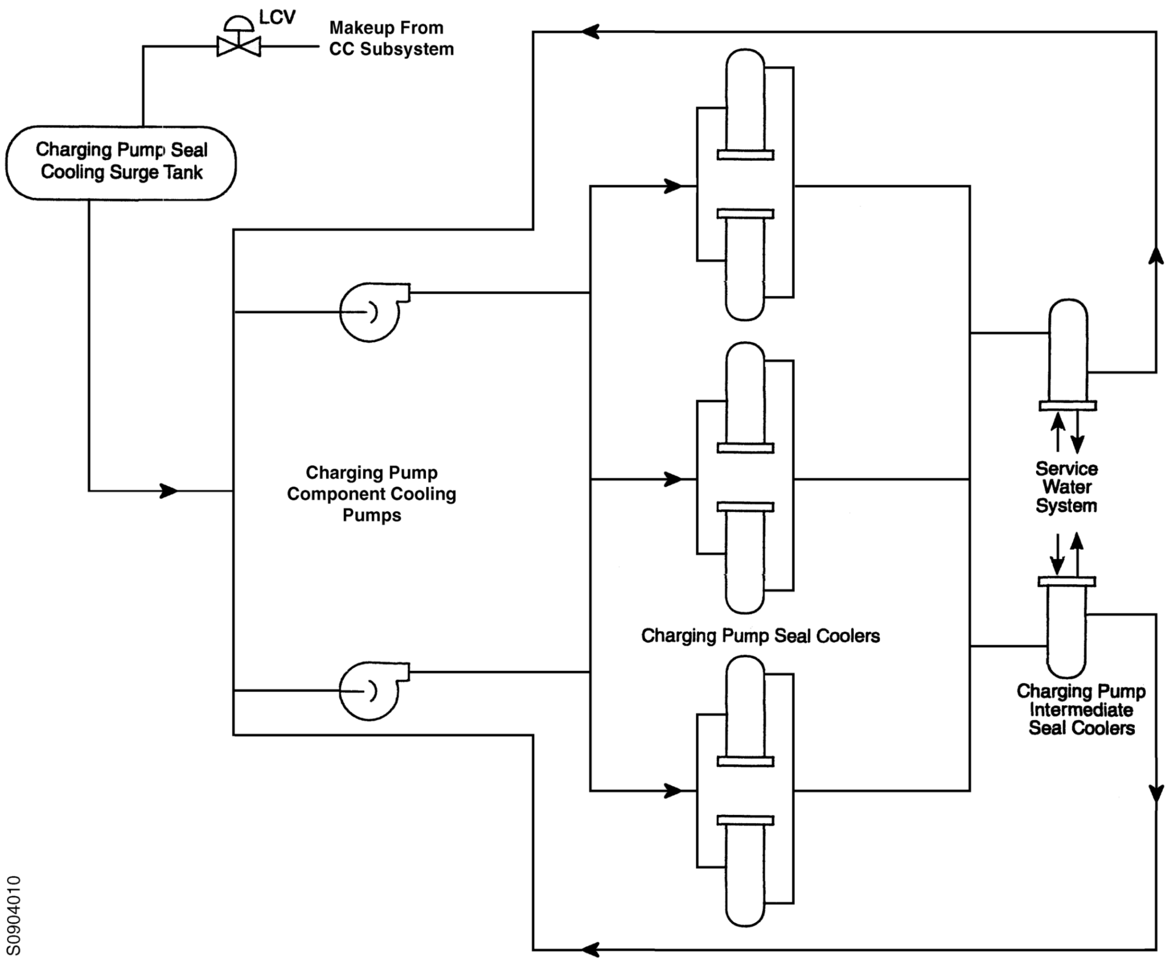


Figure 9.4-5
CHARGING PUMP COMPONENT COOLING WATER SYSTEM



9.5 FUEL POOL COOLING SYSTEM

The fuel pool cooling system shown in Figure 9.5-1 and Reference Drawing 1 pumps borated water from the spent-fuel pool through heat exchangers and back to the pool to maintain fuel pool water temperature. Additional pumps are provided for purification through an ion exchanger and filter and for surface clarification. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the fuel pool cooling system was found to be adequate.

9.5.1 Design Bases

The Fuel Pool Cooling System has the capability to:

1. Maintain the temperature of the fuel pool water below 140°F during a normal core offload condition commencing 100 hours after shutdown. A normal core offload condition is a planned offload of up to a full core. The most limiting condition for normal core offload is a full core offload following refueling of the other unit.
2. Maintain the temperature of the fuel pool water below 170°F during an abnormal core offload condition commencing 100 hours after shutdown. An abnormal core offload is an unplanned offload of up to a full core. The most limiting condition for an abnormal core offload is an unplanned full core offload following back-to-back refuelings of both units.

The fuel pool cooling system is designed as a Seismic Class I system and consists of two complete cooling loops, each of which has a design water flow rate of 4200 gpm. Each loop can remove about 34×10^6 Btu/hr while maintaining the fuel pool outlet water temperature at 170°F, assuming that the component cooling water system, which is the heat sink, is at a temperature of 105°F.

The fuel pool water temperature is continuously indicated in the control room, and an alarm in the control room alerts the operator prior to this temperature reaching 140°F. There are also indicators in the control room to inform the operator when either or both of the fuel pool cooling pumps are operating.

The fuel pool cooling system is also designed to maintain the clarity of the refueling water to permit observation of fuel element placement during refueling operations. The system also maintains a minimum pool water level of 41 ft. 2 in., which will provide a minimum water shield of 20 feet in depth (Section 11.3).

In addition, wide range level instrumentation provides indication of spent fuel pit level in the cable spreading room. The instrumentation measures spent fuel pit water level from 7 inches above the top of the fuel racks to 10 inches above normal water level.

The design data for the fuel pool cooling system components are given in Table 9.5-1.

9.5.2 System Description

The fuel pool cooling system has two shell and tube coolers, two circulating pumps (4200 gpm), and two full-size purification pumps (150 gpm), all located in the fuel building. The coolers and pumps are arranged for cross-connected operation. The coolers are cooled with component cooling water.

The purification pumps take suction at the outlet of the fuel pool coolers and pump water to a 45-ft^3 ion exchanger and filter located in the auxiliary building. The ion exchanger or the filter can be bypassed if not required. The water returns to the fuel pool at the far end opposite the suction point to ensure mixing. The surface of the water is kept clear of floating matter by two skimmers connected to two skimmer pumps (10 gpm). The pumps discharge to the skimmer filters, after which the water returns to the far end of the pool.

The purification system is operated independently of the cooling system, and remains in operation essentially continuously to maintain a clean, clear pool. The maximum allowable differential pressure across the purification filter is 25 psid. The maximum allowable differential pressure across the demineralizer (ion exchanger) is 25 psid. If the delta P exceeds the allowable value, the filter is replaced or the demineralizer resin is replenished.

The lowest level of pipe penetration through the fuel pool structure is 20 feet above the top of stored fuel elements.

9.5.2.1 **Components**

All piping, valves, and components of the fuel pool cooling system that come in contact with the fuel pool water are austenitic stainless steel.

9.5.3 Design Evaluation

9.5.3.1 **Availability and Reliability**

Two circulating pumps and two fuel pool coolers are provided to ensure system availability for meeting cooling requirements using the appropriate alignments of required pumps and coolers. For most normal conditions, the system capacity is sufficient to maintain pool temperatures below 140°F with one pump and one cooler. During refueling operations, flexibility exists to add the other cooler or the other cooling loop, as required to meet the existing heat load while maintaining the pool temperatures consistent with fuel handling operations. The design condition presenting the most limiting capacity for the system is the back-to-back refueling case. In this case, one pump and two coolers maintain the pool below 140°F, with restrictions on allowable Component Cooling water temperature (Section 9.5.3.4), leaving the standby pump to be placed in operation if the operating pump should malfunction. Sufficient cooling water is available to increase the system heat rejection capacity and maintain the pool below 170°F at the abnormal heat load with one pump and one cooler, if required. Redundant piping is provided from the fuel pool through the pumps and coolers to the main return header located above the pool water level.

9.5.3.2 **Purification of Water**

The 150-gpm filtering rate of the purification system results in a refueling water cleanup half-life of 2 days, and maintains suspended solids at a low concentration for optical clarity. The skimmer filter removes particles that fall and float on the water surface. This reduces the amount of impurities that enter the water and also reduces surface refraction.

The fuel pool purification system removes both radioactive and nonradioactive particulates from the pool water. The purity of water is normally maintained between 0.0 to 0.3 ppm, with a maximum particulate concentration of about 0.4 ppm. This purity level provides sufficient optical clarity for refueling operations. Based on samples taken since station start-up, the major isotopes that have been detected in the pool water, with approximate concentrations, are listed in Table 9.5-2.

Crud buildup along the sides of the fuel pool has not significantly affected the radiation levels at the edge of the pool. Crud buildup on the sides of the pool is removed with hydrogen peroxide (H_2O_2).

9.5.3.3 **Fuel Pool Water Leakage Control**

Slow leakage of water from any point in the piping or components of the cooling or purification systems can be stopped by valves mounted close to the pool penetrations. An alarm is provided on the pool to sound at a level loss of approximately 0.5 foot; this provides ample time to isolate the leaking equipment. Further, a large piping system leak can reduce the water level in the pool to only 4 feet below normal, since at this elevation the water level is below the pipe penetrations in the pool wall. This minimum water level ensures at least 20 feet of water over stored fuel and provides ample shielding and cooling.

9.5.3.4 **Heat Load**

At Surry a single spent fuel pool provides storage of irradiated fuel assemblies for both units. For normal refueling operations, a full core offload of one unit following a refueling of the other unit represents the most limiting spent fuel pool heat load. For this back-to-back refueling condition the assumption is made that as soon as one unit has completed refueling, the second unit begins its refueling outage. This results in the most recently discharged batch of fuel prior to the current refueling having a decay time of 28 days.

The offload of the core for the current refueling is assumed to begin at 100 hours after shutdown and finish at 130 hours after shutdown. The 30 hours assumed for off-loading of the core is conservative with respect to actual practice.

The heat load from the irradiated fuel in the pool prior to these refuelings is accounted for through a cumulative decay heat load determined from successive refueling discharges decayed for 1.5 to 10.5 years. At this time the pool would be full except for a full core discharge capability (157 storage cells).

The back-to-back refueling scenario results in a heat load on the spent fuel pool cooling system of 37.5×10^6 Btu/hr. At this heat load the spent fuel pool cooling system can maintain the pool temperature below 140°F with one pump and two coolers in operation and the component cooling water supply temperature at a maximum of 97°F.

The most limiting spent fuel pool heat load for abnormal core offload is determined by assuming an unscheduled shutdown of the first unit which requires a full core offload after the second unit has gone back on-line following back-to-back refuelings. The heat load is conservatively determined assuming the most recently discharged fuel batch has a decay time of 28 days, the next most recently discharged batch has a decay time of 56 days, and the core being off-loaded to have operated for a sufficient length of time to produce maximum decay heat prior to being transferred to the pool by 130 hours after shutdown of the unit. The heat load from the irradiated fuel in the pool prior to the refuelings is accounted for through a cumulative decay heat load determined from successive refueling discharges decayed for 1.5 to 10.5 years. The abnormal condition also assumes that the unscheduled full core offload completely fills the pool. This results in a heat load of 40.8×10^6 Btu/hr placed on the spent fuel pool cooling system. The capability of the spent fuel pool cooling system is more than sufficient to maintain the pool temperature below 170°F with the component cooling water supply temperature at 105°F through the use of one pump and two coolers.

The design flow rate of the component cooling water through the shell side of each fuel pool heat exchanger is 1322 gpm. The actual flow rate is controlled based on cooling water temperature and the fuel pool water temperature. The component cooling water system is discussed in Section 9.4.

9.5.3.5 **Malfunction Analysis**

The consequences of the malfunction of various fuel pool cooling system components are described by Table 9.5-3.

9.5.4 Tests and Inspection

The fuel pool level and temperature instrumentation are calibrated on a periodic basis. Periodic visual inspections and preventive maintenance are conducted on all system components. Periodic sampling of fuel pool water is conducted.

9.5 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-081A	Flow/Valve Operating Numbers Diagram: Fuel Pit Systems

Table 9.5-1
FUEL POOL COOLING SYSTEM COMPONENT DESIGN DATA

Fuel Pool Coolers		
Number	2	
Design duty, each	34,750,000 Btu/hr	
	Shell	Tube
Fluid flowing	Component cooling water	Fuel pool water
Design pressure	150 psig	100 psig
Design temperature	200°F	200°F
Operating temperature, max	157°F outlet	170°F inlet
Operating pressure	60 psig	40 psig
Material	Carbon steel	SS 304
Design code	ASME III, Class C	ASME III, Class C
Spent-Fuel Pool Pumps		
Number	2	
Type	Horizontal centrifugal	
Motor horsepower	100 hp	
Seals	Mechanical	
Capacity	4200 gpm	
Head at rated capacity	62 ft	
Design pressure	100 psig	
Design temperature	250°F	
Materials		
Pump casing	SS 304	
Shaft	SS 316	
Impeller	SS 304	
Purification Pumps		
Number	2	
Type	Horizontal centrifugal	
Motor horsepower	20 hp	
Pump capacity	150 gpm	
Seals	Mechanical	
Head at rated capacity	198 ft	
Design pressure	225 psig	
Design temperature	250°F	
Materials		
Pump casing	SS 316	
Shaft	SAE 4140	
Impeller	SS 316	

Table 9.5-1 (CONTINUED)
FUEL POOL COOLING SYSTEM COMPONENT DESIGN DATA

Fuel Pool Filter	
Number	1
Retention size, max	5µ
Filter element capacity, normal/max	150/150 gpm at 5 psi ΔP
Material	SS 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III, Class C
Skimmer Pumps	
Number	2
Type	Horizontal centrifugal
Motor horsepower	1 hp
Seal	Single mechanical
Capacity	10 gpm
Head at rated capacity	30 ft
Design pressure	150 psig
Design temperature	170°F
Materials	
Pump casing	SS 316
Shaft	SAE 4140
Impeller	SS 316
Fuel Pool Ion Exchanger	
Number	1
Active volume	45 ft^3
Design pressure	200 psig
Design temperature	250°F
Demineralizer resin	50/50 cation-anion
Materials	SS 316 L
Design code	ASME III, Class C
Skimmer Filter	
Number	2
Retention size filter element	10µ
Capacity	10 gpm at 2 psi ΔP
Material	SS 316
Design pressure	150 psig
Design temperature	170°F
Fuel Pool Cooling Piping and Valves	
Materials	Austenitic stainless steel
Design code	ANSI B31.1

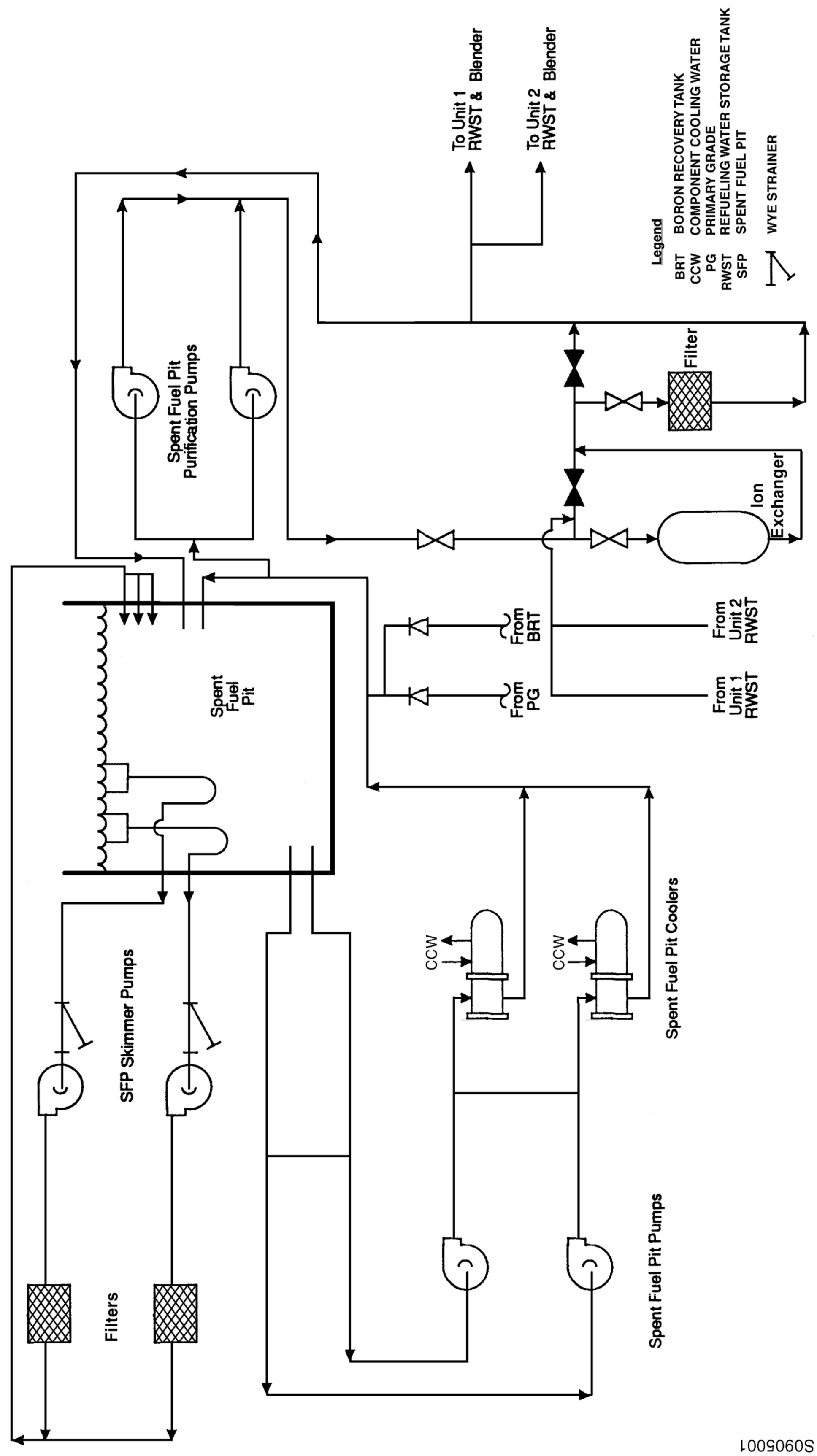
Table 9.5-2
MAJOR ISOTOPES DETECTED IN FUEL POOL WATER

Isotope	Concentration (μCi/ml) Normal	Maximum	Minimum
Cs-134	0	1.2×10^{-4}	0
Cs-137	10^{-4} to 10^{-5}	1.3×10^{-4}	0
Co-58	10^{-3} to 10^{-4}	1.5×10^{-3}	6.6×10^{-4}
Co-60	10^{-3} to 10^{-4}	1.1×10^{-3}	4.8×10^{-4}
I-131	0	6.5×10^{-5}	0
Gross activity	10^{-3} to 10^{-5}	1.1×10^{-3}	5.0×10^{-5}

Table 9.5-3
MALFUNCTION ANALYSIS

Component	Malfunction	Comments and Consequences
Spent-fuel pool pumps	Pump fails to start, or fails during operation	The redundant cooling loop would remain operational. The operator in the control room would be alerted of the failure by pump status light and/or temperature alarm and the redundant pump would be manually started and placed in service. In the event the operating pump stops, over 1 hour is available before the pool water heats up 10°F; therefore, a number of hours would be available to start the spare pump. The failed pump would be repaired and returned to service. Furthermore, normal power to both pumps is supplied from station emergency buses, alternate power is supplied from the B bus and back-up power is supplied from the opposite emergency bus.
Fuel pool coolers	Loss of function	Although a passive failure of this type would not cause a loss of function, e.g., leaks might occur, the redundant cooler could be placed in service while the failed cooler is repaired. As with the pump, sufficient time is available to manually realign the coolers.
Pumps, coolers, piping, valves, and other components	Leaks of any size	A slow leak (less than 100 gpm) will permit over 2 hours to isolate the leak before loss of 1 foot of water. A large leak can only reduce water to the lowest pool penetration, which is at a level to ensure adequate shielding.

Figure 9.5-1
FUEL POOL COOLING SYSTEM



9.6 SAMPLING SYSTEM

The station sampling systems provide for obtaining samples from primary and secondary plant systems, as well as for obtaining post-accident samples should they be required. Chemistry sampling of various process fluids and gases ensures that (1) fuel element failures are promptly detected, (2) plant systems are functioning properly, (3) corrosion is being adequately controlled, and (4) samples are available for determining certain post-accident system conditions, if required. The primary and secondary plants are sampled routinely. Data from the sample systems throughout the plant are relied upon for daily operations, as well as to provide assessment information in the event of a fuel element failure of a design basis accident.

9.6.1 Design Bases

9.6.1.1 Sampling System—Routine Operation

Process fluids and gases are representatively sampled for testing to obtain data from which performance of the station, equipment, and systems may be determined.

Routine samples of process fluids and gases associated with both the primary and secondary systems are either taken periodically or are continuously monitored. Two general types of samples are obtained by the sampling system: high-temperature samples (greater than 150°F) such as the reactor coolant system samples, and low-temperature samples (less than or equal to 150°F) such as the high-level waste drain tank samples. Various samples taken are listed in Table 9.6-1.

Primary samples are analyzed to determine the amount of radioactivity in the reactor coolant. If the radioactivity level is high, a reactor coolant sample is analyzed for iodine and other isotopes and counted as an indication of defects in fuel cladding. The frequency of sampling for radiochemical analysis of the reactor coolant is given in the Technical Specifications.

9.6.1.2 High Radiation Sampling System—Post-Accident Operation

The High Radiation Sampling System (HRSS) is no longer required for post accident sampling and has been removed from the Surry Power Station Technical Specifications but is maintained to provide contingency measures in accordance with Reference 1. Surry Power Station contingency measures are being provided by maintaining portions of the HRSS to facilitate acquiring diluted and non-diluted samples of the RCS, containment sump, and containment atmosphere. These samples can then be analyzed on site or sent off site for analysis. Station procedures control the sampling and analysis evolutions. The in-line analysis capability of the HRSS is no longer required for timely analysis of post-accident samples and will not be maintained. The system is designed to obtain and analyze representative samples of reactor coolant, the containment atmosphere, and the containment sump after an accident. Sampling and analysis of reactor coolant and containment atmosphere samples can provide information needed to assess and control the course of recovery from an accident. The system provides the ability to obtain grab samples from each reactor coolant hot leg, each reactor coolant cold leg, the residual heat removal system, the chemical and volume control system mixed-bed demineralizer effluent, containment sump, and the containment atmosphere. The system has the capability to cool and depressurize samples at high temperature and high pressure to allow grab sampling and in-line chemical analysis; however, in-line chemical analysis is no longer performed.

The system also provides the means to remotely dilute reactor coolant and containment sump samples by a factor of 1000 to reduce the personnel exposure levels that would otherwise be associated with post-accident sampling. This initial dilution also reduces the exposure that would be associated with subsequent manual dilutions, if required.

The diluted and undiluted liquid grab samples and the containment air samples are put into specially designed transfer carts with integral shielding. Placement of the samples inside the shields can be accomplished with minimal operator exposure because the cart is integrally designed to nest within the sample panel. The transfer carts facilitate movement to designated areas for isotopic or chemical analysis with low operator exposure.

The sampling system has the ability to strip reactor coolant of dissolved gases for grab sampling and analysis.

An in-line chemical analysis panel is no longer used but was designed to facilitate remote measurement of important chemical parameters with a minimum of manual action or exposure to the operator. This chemical analysis panel has the capability to measure primary coolant pH, boron, oxygen concentration, and hydrogen concentration, as well as containment hydrogen concentration. The capability for in-line chloride measurement utilizing a portable ion chromatograph is also provided. Each parameter (except chloride) is either indicated or recorded on a remote-control panel located in the cable spreading room.

The high radiation sampling system panels are located within existing space in the auxiliary building. The reactor coolant is drawn from sample system lines outside of containment, upstream of the normal sample system coolers.

Controls are provided to prevent post-accident samples from being inadvertently introduced to the normal sample room.

Sample liquid resulting from recirculation, purging, and drainage can be routed to the high radiation sampling system waste tank, from which the fluid can be pumped or displaced with nitrogen back to the containment sump. Connections are provided to recirculate, purge, and drain non-accident liquid samples via normal sample system flow paths for purposes of operator training and periodic equipment testing.

The containment atmosphere sample panel has the capability to take suction from within the hydrogen monitor system. Motive force for the containment atmosphere sample panel is provided by an integral nitrogen eductor. The discharge of the containment atmosphere panel is routed back to the containment via the high radiation sampling system waste tank and evacuating compressor.

9.6.2 Description

9.6.2.1 Sampling System—Routine Operation

The sample lines coming from within the containment contain high-temperature samples, with the exception of the pressurizer relief tank sample. Where two or more samples join into a common header (i.e., the primary coolant cold-leg samples), each individual sampling line has a solenoid-operated valve in the line that can be remotely operated from a control board in the auxiliary building sampling room. The primary coolant hot-leg and cold-leg samples flow through delay coils before penetrating the containment. These delay coils permit sufficient decay of nitrogen-16 so that these samples can be handled in the sampling room.

Sample lines penetrating the containment have two automatically operated valves in the line, one just inside and one just outside the containment. These trip valves close on receipt of a safety injection signal. Samples may also be obtained from interfacing systems (e.g., gaseous waste) which have containment isolation valves that may be operated under administrative control in accordance with Technical Specifications. The high-temperature samples pass through sample coolers located in the auxiliary building sampling room. These coolers cool the high-temperature samples to a temperature low enough for safe handling. Sample flows leaving the cooler are manually throttled and can be directed to a purge line or to the sampling sink. The pressurizer vapor space samples, in addition, pass through capillary tubes that limit the flow of steam.

The sampling lines from sampling points outside the containment but inside the auxiliary building also discharge to the auxiliary building sampling sink. Sample lines from sampling points in the turbine building discharge to one of the turbine building sample sinks. The high-temperature samples also pass through sample coolers and are manually throttled. In general, samples can either be directed to a purge line or to the sampling sink. The main steam samples also pass through capillary tubes.

The purge flows of the various samples are discharged to the volume control tank, the vent and drain system, or elsewhere, as appropriate. The radioactive samples in the auxiliary building sampling room discharge into hooded sampling sinks.

The on-line chemistry monitoring system (OLCMS) provides continuous monitoring from four main sample locations in the secondary system (feedwater, steam generator blowdown, main steam and condensate) and from two supplemental sample locations (condensate make-up and moisture separator reheater/heater drains). Samples are cooled by primary coolers which use bearing cooling water. Samples flow to their respective conditioning and monitoring panels which are located in the Units 1 and 2 turbine building basements. Output signals from the sample panel monitors and analyzers go to an I/O data controller for input to an onsite computer. Selected signals go to recorders in the control room.

Radiation monitors in the steam generator blowdown sample line detect primary-to-secondary leaks in the steam generators. Monitoring of the condensate pump discharge is used to detect tube leaks in the condensers.

9.6.2.2 **High Radiation Sampling System—Post-Accident Operation**

Representative post-accident liquid and gas samples from either reactor unit can be routed to one common high radiation sample system. Samples can be received from the sources listed in Table 9.6-2. The tie-in locations for all reactor coolant samples are outside the containment, upstream of the sample system coolers. Since the reactor coolant sample lines are combined into common headers inside containment, one common hot-leg sample and one common cold-leg sample for each unit is routed to the high radiation sampling system liquid sample panel.

The motive force for all reactor coolant samples is primary system pressure. A containment sump pump, appropriate for its service duty, is provided to obtain containment sump samples. The motive force for a containment atmosphere sample is provided by a nitrogen eductor contained within the containment air sample panel.

The high radiation sampling system is designed so that incoming liquid sample lines can be purged to ensure that the grab samples are representative. The line volumes will be purged several times during this operation. During post-accident conditions, primary system liquid samples are purged directly to the high radiation sampling system waste tank. The associated waste pumps can then transfer the accumulated liquid waste to the appropriate containment sump. For system test and operator training, liquid samples can be recirculated via the normal sample pathways to the appropriate volume control tank or high-level drain tank purge headers.

The high radiation sampling system is comprised of five subsystems.

These are:

1. Liquid sample panel and coolers.
2. Containment atmosphere sample panel.
3. Chemical analysis panel (use of this subsystem has been discontinued).
4. Waste tank and pump.
5. Process control panel.

9.6.2.2.1 Liquid Sample Panel and Coolers

The liquid sample panel and coolers perform multiple functions:

1. Sample cooling to about 135°F during the recirculation mode and about 120°F during the grab sample mode.
2. Sample depressurization.

3. Liquid degassing to obtain a representative dissolved gas sample.
4. Liquid degassing to the extent necessary to allow in-line chemical analysis downstream in the chemical analysis panel (use of this subsystem has been discontinued).
5. Provide undiluted liquid grab sample inside a shielded transfer cask.
6. Provide diluted (1000 to 1) liquid grab sample inside a shielded transfer cask.
7. Provide diluted dissolved gas grab sample inside a shielded syringe.
8. Provide integral shielding to minimize operator exposure while working in front of the panel.
9. Provide a ventilated cabinet, held below atmospheric pressure, to contain potential subsystem leakage. Cabinet ventilation is connected to the auxiliary building HVAC system.

The liquid sample subsystem is divided into three modules, based upon the pressure of the incoming liquid. A reactor coolant module handles hot-leg, cold-leg, and residual heat removal system samples. A demineralizer module handles the chemical volume and control system mixed-bed demineralizer effluent samples. A radwaste module handles the containment sump samples.

The liquid sample subsystem contains provisions for flushing with station primary-grade water. The flush water is routed to the high radiation sampling system waste tank.

9.6.2.2.2 Containment Air Sample Panel

The containment air sample panel performs the following functions:

1. Provides the motive force to obtain a representative grab sample of containment atmosphere. A nitrogen eductor is provided that is capable of operation when the containment pressure is either slightly negative or at the maximum post-accident pressure.
2. Provides three shielded sample bombs and a gas partitioner device to obtain containment atmosphere samples on a preprogrammed timer sequence. The gas partitioner device is independently controlled and separates the containment air sample for particulate, iodine, and noble gas determination.
3. Provides a motive force by a nitrogen eductor to deliver containment air sample flow to the chemical analysis panel for atmospheric analysis to determine the hydrogen concentration.
4. Provides a means to purge and backflush containment air sample lines back to the affected containment.
5. Provides an integrally shielded panel front to minimize post-accident operator dose rates.
6. Provides a ventilated cabinet held below atmospheric pressure to contain potential subsystem leakage. Cabinet ventilation is connected to the auxiliary building HVAC system.

9.6.2.2.3 Chemical Analysis Panel

The in-line chemical analysis panel is no longer required for post accident sampling. The chemical analysis panel is no longer used but was designed to perform the following functions:

1. Accept a preconditioned, cooled, depressurized and degassed, liquid sample from the liquid sample subsystem for post-accident chemical analysis for boron, pH, dissolved hydrogen and dissolved oxygen, and hydrogen concentration in post-accident containment atmosphere samples.
2. Provide remote readout of chemical analysis panel parameters on the remote process control panel of the high radiation sampling system.
3. Provide an integrally shielded panel front to minimize post-accident operator dose rates.
4. Provide a ventilated cabinet held below atmospheric pressure to contain potential subsystem leakage. Cabinet ventilation is connected to the auxiliary building HVAC system.
5. Provide the necessary connections to connect a portable ion chromatograph for in-line chloride analysis of the reactor coolant.

Table 9.6-3 lists the types of instrumentation to be used for determination of post-accident chemical parameters; however, in-line chemical analysis is no longer performed. Instrumentation has been selected based upon the following criteria:

1. The ability to measure accurately the full anticipated range of parameters.
2. The ability to withstand high radiation fields.
3. The ability to reproduce results after calibration.
4. The ability to measure chemical parameters with small sample volumes.

The chemical analysis panel is designed with built-in instrument calibration equipment. Instrument calibration will be performed by station personnel on a periodic basis to maintain a ready condition and to minimize instrument drift.

9.6.2.2.4 Waste Tank, Pumps, and Evacuating Compressor

The waste tank and pumps have the ability to collect and return system purge and flush liquids to either containment or to the plant high level waste drain tank. The liquid sample purge return lines to the containment are routed to the containment sump. The waste tank is sized to hold the volume of liquid residue generated by the acquisition of two post-accident samples.

Two 100%-capacity waste tank pumps are provided to pump the tank contents back to the containment. A nitrogen purge connection is provided to force the contents of the tank back to the containment in the event of pump failure, and also to maintain a nitrogen blanket in the waste tank to preclude accumulation of hydrogen.

During post-accident conditions, the waste tank can be held under a slight vacuum by an evacuating compressor, and can be nitrogen-blanketed. An evacuating compressor is provided to maintain the tank under negative pressure. The evacuating compressor also discharges containment air samples which enters the waste tank from the containment air sample panel. A bleed and feed system will control the evacuating compressor and nitrogen purge flow. The evacuating compressor discharge can be directed to either containment.

Tables 9.6-4, 9.6-5, and 9.6-6 provide design data for the waste tank, the waste tank pumps, and the evacuating compressor, respectively.

9.6.2.2.5 Process Control Panel

The process control panel performs the following functions:

1. Provides remote location in the service building in a low dose rate area for operation of the high radiation sampling system remotely operated valves, with the exception of the routine sample system containment isolation valves, which are operated from the control room.
2. Provides space for chemical analysis panel instrument indicators and recorders.

The process control panel contains a complete system graphic display for the other four subsystems. A communication system is provided between the sample panel area in the auxiliary building, the process control panel in the service building, and the control room.

9.6.2.2.6 Instrumentation Application

The chemical analysis panel measured parameters are no longer used but were designed to indicate and record on the remote process control panel. Parameters measured were boron concentration, pH, dissolved oxygen, chloride, dissolved hydrogen, and containment air hydrogen concentration; however, in-line chemical analysis is no longer performed. Local flow and pressure indication are on the face of the liquid sample, containment atmosphere, and chemical analysis panels to enable the operator to manually align and adjust system flows.

The process control panel permits remote operation of the high radiation sampling system automatic valves, including those routine containment sample system valves, which are normally operated from a panel in the routine sample room.

The maximum postulated activity concentration of post-accident samples is far in excess of the capabilities of normal counting equipment and geometries. Thus, sample dilution will be required prior to analysis. The liquid sample subsystem provides a 1000 to 1 dilution of reactor coolant samples. However, depending upon the accident condition, additional final dilution can be accomplished in a shielded fume hood. The diluted sample can then be analyzed by existing laboratory counting equipment.

The liquid sample subsystem can provide a shielded syringe sample of diluted reactor coolant gases that can also be further diluted, if necessary, in the adjacent shielded fume hood. These samples can then be analyzed in existing laboratory counting equipment.

The containment atmosphere samples are collected in 5 cc shielded sample casks in the containment atmosphere sample panel. Samples of 1 ml will be isotopically analyzed by a Ge detector, which measures through a 0.25-inch aperture in the sample vessel lead shield. The shield apertures are designed to allow measurement in several orientations. Halides and noble gases can be analyzed together. Successive analyses of containment air samples collected on a known time sequence enable the operator to determine the extent of the accident and the effectiveness of the containment spray system.

A particulate, iodine, and gas sample is connected to and operates in conjunction with the containment air sample panel. This device separates the containment air into components for analysis in the laboratory.

Design conditions of the various sampling panels are given by Table 9.6-7.

9.6.3 Design Evaluation

9.6.3.1 **Sampling System—Routine Operation**

If a critical sampling line becomes nonfunctional due to some malfunction, there is at least one alternate path that can be used to obtain a similar periodic sample, or for continuous monitoring. If one of the steam generator blowdown radiation monitors malfunctions, a second similar radiation monitor in each unit can be used. If one of the steam generator blowdown sampling lines becomes inoperative, the condenser air ejector radiation monitor provides indication of a steam generator primary-to-secondary-side leak.

9.6.3.2 **High Radiation Sampling System—Post-Accident Operation**

The high radiation sampling system equipment is designated Quality Group D, non-seismic, as defined in Regulatory Guide 1.26. Seismic failure will not damage station safety-related equipment or the building structures. Electrical power supply is from the station service buses. In the event of a loss of normal power, a manual selector switch is used to provide power from the opposite unit.

The air-operated trip valves in the residual heat removal sample lines and the reactor coolant system hot-leg and cold-leg sample lines have been replaced with direct-acting solenoid valves. This ensures that the valves can be reopened to draw the sample, under the single-failure criterion after an accident. The air-operated valves that are required to operate in order to obtain the reactor coolant sample are furnished with dedicated instrument air accumulators so that the ability to open the valves remotely will be available in the event that the station instrument air system is temporarily nonfunctional. System interlocks are provided throughout to perform the following basic functions:

1. To ensure that samples obtained after an accident can only be returned to the affected containment. A similar philosophy is applied to system purge and flush fluids.
2. To ensure that post-accident sample fluid cannot inadvertently enter the routine sample system.

Permanent system connections to the station nitrogen system are provided, along with a nitrogen bottle backup system.

Redundant waste tank pumps are provided to pump post-accident samples back to the affected containment. Nitrogen can be used to empty the waste tank in the event of dual pump failure or loss of electric power.

System flush water is obtained from the station's primary grade water system. Primary-grade water connections to the system are quick-disconnect type. After each use of flush water, the system will be disconnected to minimize the possibility of primary-grade water contamination by post-accident samples. Each sample acquisition will be followed by a flush to keep background radiation levels to a minimum, in accordance with the ALARA concept.

A shielding analysis has been performed to ensure that operator exposure while obtaining and analyzing a post-accident sample will be less than 5 rem whole-body and 75 rem to the extremities. Operator exposure will be accumulated while entering and exiting the sample panel area, operating sample panel manual valves, positioning the grab sample into the shielded transfer carts, and performing additional manual sample dilutions, if required, for isotopic analysis. The major sources of operator exposure are from:

1. General auxiliary building background from components not associated with the high radiation sampling system. Operator exposure is limited by the stay time associated with sample panel manual operations, and by selecting entrance and exit routes to the sample room via the lowest dose rate paths.
2. Direct radiation from sample lines that are routed behind the shielded sample and analysis panels. Operator exposure is limited by the integral shielding located in the front of each of the system sample analysis panels. This shielding consists of up to 6 inches of lead shot poured into panel front sections.
3. Backscatter from the walls and roof behind and above the shielded sample and analysis panels. Operator exposure is limited by positioning the panel in an orientation such that the distance from the back of the panel to the nearest wall is maximized to the greatest extent practicable. A shadow shield is provided above the normal operator area.

9.6.4 Tests and Inspections

9.6.4.1 **Sampling System—Routine Operation**

Most components are used regularly during power operation, cooldown, and/or shutdown, thus providing assurance of the availability and performance of the system. The continuous monitors are periodically tested, calibrated, and checked to ensure proper instrument response and operation of alarm functions.

9.6.4.2 **High Radiation Sampling System—Post-Accident Operation**

The high radiation sampling system is no longer required for post accident sampling and the system has been removed from Surry Power Station Technical Specifications. However, the system remains in place and available, and portions of the system will be maintained to provide contingency sampling measures. Station personnel are trained on the system to ensure familiarity with and to test the functions and operations of the system that are required for use as contingency sampling measures. The chemical analysis instrumentation is no longer used, therefore calibration and testing of this portion of the system is no longer required.

9.6 REFERENCES

1. License Amendments 229 and 229 to Facility Operating License Nos. DPR-32 and DPR-37.

9.6 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-082A	Flow/Valve Operating Numbers Diagram: Sampling System, Unit 1
	11548-FM-082A	Flow/Valve Operating Numbers Diagram: Sampling System, Unit 2
2.	11448-FM-082B	Flow/Valve Operating Numbers Diagram: Sampling System, Unit 1
3.	11448-FM-082C	Flow/Valve Operating Numbers Diagram: Sampling System, Unit 1

Table 9.6-1
SAMPLING SYSTEM ROUTINE SAMPLES

I. High-Temperature Samples from Each Unit

1. Pressurizer vapor.
2. Pressurizer liquid.
3. Residual heat removal liquid taken downstream of the residual heat removal pumps.
4. Residual heat removal liquid taken downstream of residual heat exchangers.
5. Hot-leg primary coolant taken from each of the reactor coolant loops.
6. Cold-leg primary coolant taken from each of the reactor coolant loops.
7. Steam generator blowdown liquid taken from each of the blowdown lines.
8. Main steam taken from each of the main steam lines.
9. Steam generator feedwater.
10. Moisture separator reheater/heater drains.

II. High-Temperature Samples Common to Both Units

1. Auxiliary heating de-aerator.
2. Auxiliary heating boiler lower drum.
3. Auxiliary heating boiler steam drum.
4. Radwaste facility liquid waste evaporator.
5. Radwaste facility evaporator concentrates.

III. Low-Temperature Samples from Each Unit

1. Supply header to chemical and volume control system demineralizers.
2. Chemical and volume control system cation demineralizer effluent.
3. Condensate pump discharge header.
4. Chemical and volume control system de-borating demineralizers effluent.
5. Chemical and volume control system mixed-bed demineralizer effluent.
6. Volume control tank liquid.
7. Volume control tank gas space.
8. Pressurizer relief tank gas space.
9. Condensate makeup demineralizer effluent.

Table 9.6-1 (CONTINUED)
SAMPLING SYSTEM ROUTINE SAMPLES

IV. Low-Temperature Samples Common to Both Units

1. Low-level waste drain tanks liquid.
2. Boron recovery system test tanks liquid.
3. High-level waste drain tanks liquid.
4. Boron recovery tanks liquid.
5. Component cooling water.
6. Primary drain tank liquid.
7. Gas stripper liquid effluent.
8. Primary-water tanks.
9. Contaminated drains collection tanks.
10. Waste disposal evaporator test tanks. (Installed but no longer used)
11. Gas stripper surge tank gas.

V. Radwaste Facility Samples

1. Liquid waste collection tanks.
2. Liquid waste surge tanks.
3. Liquid waste monitor tanks.
4. Laundry waste monitor tanks.
5. Waste batch tanks.

Table 9.6-2
HIGH RADIATION SAMPLING SYSTEM SAMPLE POINTS

Sample Source	Number of Sample Points For Each Reactor
Reactor Coolant	
Hot leg	4 locations [a]
Cold leg	3 locations [a]
RHR loop	2 locations [a]
CVCS mixed-bed demineralizer outlet	1 location
Containment sump	1 location
Containment atmosphere	1 location

a. One common header from outside the containment is routed to the high radiation sampling system

Table 9.6-3
CHEMICAL ANALYSIS PANEL INSTRUMENTATION [a]

Parameter	Instrument or Method	Range of Measurement
I. Reactor Coolant and Containment Sump		
1. Boron [b]	Auto-Titrator	200-2000 ppm
2. pH	Probe	1-13
3. Dissolved oxygen [b]	Probe	1-20 ppm
4. Dissolved hydrogen [b]	Gas chromatograph	10-2000 cc/kg
5. Chloride	Ion chromatograph	0-20 ppm
II. Containment Atmosphere		
1. Hydrogen	Gas chromatograph	0-10%

a. Use of Chemical Analysis Panel Instrumentation has been discontinued.
b. Reactor coolant only

Table 9.6-4
HIGH RADIATION SAMPLING SYSTEM WASTE TANK

Quantity per station	1
Capacity	17 gal
Material of construction	Stainless steel
Code	ASME VIII
Design pressure	150 psig
Design temperature	150°F

Table 9.6-5
HIGH RADIATION SAMPLING SYSTEM WASTE TANK PUMPS

Quantity per station	2
Capacity	5 gpm
Material of construction	Stainless steel
Shaft seal	Double, mechanical

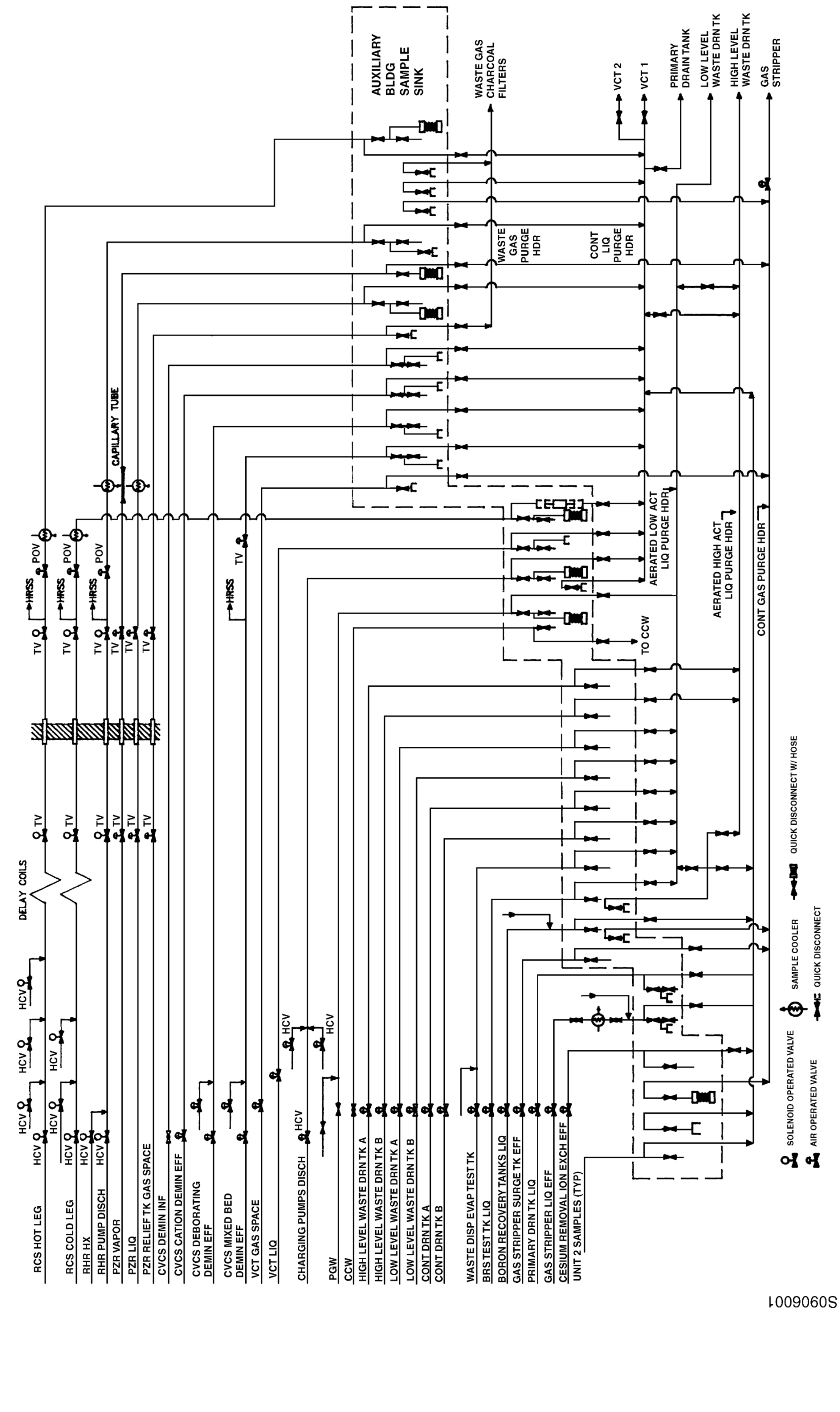
Table 9.6-6
HIGH RADIATION SAMPLING SYSTEM EVACUATING BELLOWS COMPRESSOR

Quantity per station	1
Capacity	2 scfm
Discharge pressure (max)	40 psig
Material of construction	Stainless steel
Motive device	Reciprocating bellows

Table 9.6-7
HIGH RADIATION SAMPLING SYSTEM SAMPLING PANEL DESIGN CONDITIONS

I. Process			
1. Pressure (max)	Reactor coolant sampling	2485 psig
	Sump sampling	75 psig
	Containment atmosphere	45 psig
2. Temperature (max)	Reactor coolant sampling	700°F
	Sump sampling	220°F
	Containment atmosphere	310°F
II. ln-containment ambient		
1. Pressure	9-60 psia	
2. Temperature	310°F	
3. Relative humidity	0-100%	
III. Outside containment ambient		
1. Pressure	Atmospheric	
2. Temperature	40-120°F	
3. Relative humidity (%)	0-100%	
4. Radiation	1×10^7 rads	

Figure 9.6-1
PRIMARY SAMPLING SYSTEM



9.7 VENT AND DRAIN SYSTEM

The vent and drain system collects potentially radioactive fluids and gases from various systems and discharges them either to the waste disposal system (Section 11.2) or to the boron recovery system (Section 9.2).

9.7.1 Design Bases

The vent and drain system is shown in Figure 9.7-1 and Reference Drawings 1 and 2. The drains are separated into those carrying waste fluids to the waste drain tanks for processing and disposal, and those carrying reactor coolant fluids to the primary drain transfer tank and primary drain tank for processing and recovery. The vents are separated into vents in which air is the predominant gas (filtered and discharged to the atmosphere), and vents in which hydrogen and radioactive gases are the predominant gases (discharged to the gaseous waste disposal system).

Redundancy has been provided for all active system components to ensure system operation.

The primary drain transfer tanks, primary drain coolers, relief valves, and the piping, valves, and supports of the vent and drain system conform to Seismic Class I criteria.

The design data for the vent and drain system components are given in Table 9.7-1.

9.7.2 Description

Radioactive liquids, other than letdown from the reactor coolant system (Chapter 4), are gathered and transferred to the high-level or low-level waste drain tanks in the liquid waste disposal system (Section 11.2.3) by either the high-level or low-level waste drain headers.

Both containment structures, the Auxiliary Building, the Fuel Building, both safeguards areas, the component cooling water heat exchanger area in the Turbine Building, and both incore instrumentation areas have been provided with sumps for collecting drainage. The drainage is transferred by gravity or sump pumps to either the high-level or low-level waste drain tank. Segregation of the various waste streams is based on operational and health physics discretion.

The containment sump collects all liquid waste in the containment. The auxiliary building sump collects floor drains, equipment drains, ion exchanger drains, and filter drains. The fuel building sump, safeguards area sumps, and component cooling heat exchanger pit sump collect floor drains in the respective areas.

Drain liquids originating from each reactor coolant system are discharged to a primary drain transfer tank through a high-pressure drain header. The high-pressure drain header permits high-pressure or low-pressure gravity draining of individual reactor coolant loops, the pressurizer relief tank, or the complete reactor coolant system, except for the reactor vessel. An alternate use of the high-pressure drain header is to provide a path for draining the loops during hot shutdown.

Low-pressure radioactive drains, pressurizer relief tank drains, and leakoff liquids from valve stems and reactor coolant pumps drain by gravity to the high-pressure drain header through the primary drain cooler to the primary drain transfer tank. From there, they are pumped to the primary drain tank in the boron recovery system (Section 9.2) by the primary drain transfer pumps. The primary drain cooler is provided to cool all liquid entering the primary drain transfer tank. A high-temperature alarm is provided in the primary side of the cooler outlet to warn the operator of excessive hot liquid flowing into the primary drain transfer tank.

The sample header drains flow directly to the primary drain tank. In the event of high level in the volume control tank of the chemical and volume control system (Section 9.1), the demineralized letdown flow is diverted directly to the primary drain tank through the primary drain transfer pump discharge header.

An air vent header is provided in each reactor containment and may be used to vent the reactor coolant system and components during filling operations. A vent pot located at the end of this header separates any entrained liquid for drainage by gravity to the containment sump. Air leaving the vent pot is discharged to the gaseous waste disposal system (Section 11.2.5). Vents from the ion exchangers and demineralizers, the component cooling surge tank, and waste drain tanks are handled in the same manner.

Radioactive gases are vented to the gaseous waste disposal system. Included in this category are vents from the pressurizer relief tanks, volume control tanks, reactor coolant pumps standpipe vent, bypass vents, and the sampling system gas sample purge line. The gases can also be vented to external process systems following an accident. Flanged connections with isolation valves and reach rods are provided for this purpose. In order to reduce exposure, the connections are located in an area that permits access after an accident.

Piping for the vent and drain systems is designed in accordance with the ANSI B31.1 Code for Pressure Piping. Isolation valves are provided in all vent and drain lines from the containment structures (Section 5.2).

The Teflon seats and packing in the trip valves of the primary drain transfer tank vent lines have been replaced with ethylene propylene seats and graphite packing material. In addition, the ball valves in the primary drain transfer pump discharge line have been replaced with diaphragm valves containing ethylene propylene rubber diaphragms. The ethylene propylene is qualified to 1.0×10^7 rads which is above the calculated total integrated doses of 7.4×10^6 rads and 5.0×10^6 rads, respectively, for the valves. The Teflon was only qualified to 1.0×10^4 rads. These changes ensure that the valves will function as designed in the calculated radiation fields.

9.7.3 Design Evaluation

The vent and drain system is sized to handle the maximum amounts of liquids and gases expected during station operation. Sizing the equipment for these maximum values results in design parameters shown in Table 9.7-1.

Austenitic stainless steel piping is used to transfer liquids and radioactive gaseous waste; carbon steel piping is used for nonradioactive gases.

The fuel building sump pumps are a duplex pump arrangement. The pumps, which are full-size, are controlled by float switches that cycle the pumps on and off. An alternator is provided to obtain equal wear on the pumps. Two additional float switches are provided; the first one starts the standby pump if the operating pump fails, and the second one sounds an alarm on high sump level.

The auxiliary building sump pumps are a duplex pump arrangement. The pumps, which are full-sized, are controlled by a level detector that cycles the pumps on and off, and provides an alternator to obtain equal wear on the pumps. The level detector also starts the standby pump if the operating pump fails, and sounds an alarm on high sump level.

The containment sump pumps are a duplex pump arrangement. Each pump is full-size and independently controlled. One pump is in automatic service, the other in standby. When the water level in the sump reaches a specified height, an alarm sounds and the pump starts. The pump stops automatically upon emptying the sump. Containment isolation valves are provided in the discharge piping. The isolation valves are normally open but close upon a safety injection signal loss of power or air to the valves, or operation of the test switch. When initiated, the containment isolation signal closes the valves or overrides the pump start signal to keep the isolation valves closed.

The primary drain transfer pumps are full-size and independently controlled. Two pumps are provided for each unit. One pump is in automatic service, the other on standby. When the water level in the tank reaches a specified height, an alarm sounds and the pump starts. The pump stops automatically upon emptying the primary drain transfer tank. Containment isolation valves are provided in the discharge piping and are interlocked with the pump controllers. The isolation valves open and close on pump start and stop. When initiated, the containment isolation signal closes the valves or overrides the pump start signal to keep the isolation valves closed.

The primary drain coolers and primary drain transfer tanks and interconnecting piping, valves, and supports are designed as Seismic Category I components. They are also protected from the design tornado by being located inside the containment structures.

9.7.4 Tests and Inspections

Formal testing of this system is unnecessary, since it is in normal day-to-day operation. Inspection is performed in accordance with normal plant maintenance procedures.

9.7 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-083A	Flow/Valve Operating Numbers Diagram: Vent and Drain System, Unit 1
	11548-FM-083A	Flow/Valve Operating Numbers Diagram: Vents and Drains System, Unit 2
2.	11448-FM-083B	Flow/Valve Operating Numbers Diagram: Vent and Drain System, Unit 1
	11548-FM-083B	Flow/Valve Operating Numbers Diagram: Vents and Drains System, Unit 2

Table 9.7-1
VENT AND DRAIN SYSTEM COMPONENT DESIGN DATA

Primary drain transfer tanks	
Number	2 (one for each unit)
Capacity	Approximately 725 gal
Design pressure	200 psig
Design temperature	400°F
Operating pressure	Atmospheric
Operating temperature	150°F
Base metal material	A442 Gr 60
Cladding	A240 SS 304L
Design code	ASTM III, Class C
Primary vent pots	
Number	2 (one for each unit)
Capacity	20 gal
Design pressure	25 psig
Design temperature	200°F
Operating pressure	Atmospheric
Operating temperature	200°F
Base metal material	SS 304
Design code	ASTM III, Class C
High-level waste drain filter	
Number	1
Retention size	5 µm
Filter element	Fiber
Capacity, normal	50 gpm at 2.5 psi ΔP
Capacity, max	75 gpm at 5 psi ΔP
Material	SS 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III, Class C
Low-level waste drain filter	
Number	1
Retention size	5 µm
Filter element	Fiber
Capacity, normal	50 gpm at 2.5 psi ΔP
Capacity, max	75 gpm at 5 psi ΔP
Material	SS 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III, Class C

Table 9.7-1 (CONTINUED)
VENT AND DRAIN SYSTEM COMPONENT DESIGN DATA

Safeguards area sump pumps	
Number	4 (two for each unit, one required)
Type	Vertical centrifugal single-stage
Motor horsepower	1 hp
Seal	Packing
Capacity	25 gpm
Head at rated capacity	39 ft
Design pressure	150 psig
Design temperature	180°F
Materials	
Pump casing	Cast iron
Shaft	Steel
Impeller	Bronze
Fuel building sump pump	
Number	2 (one required)
Type	Vertical centrifugal single-stage
Motor horsepower rating	3 hp
Seal	Packing
Capacity	25 gpm
Head at rated capacity	74 ft
Design pressure	150 psig
Design temperature	350°F
Materials	
Pump casing	SS 304
Shaft	SS 304
Impeller	SS 304
Auxiliary building sump pump	
Number	2 (one required)
Type	Vertical centrifugal single-stage
Motor horsepower	2 hp
Seal	Packing
Capacity	50 gpm
Head at rated capacity	49 ft
Design pressure	150 psig
Design temperature	350°F
Materials	
Pump casing	SS 304
Shaft	SS 304
Impeller	SS 304

Table 9.7-1 (CONTINUED)
VENT AND DRAIN SYSTEM COMPONENT DESIGN DATA

Reactor Containment Sump Pumps	
Number	4 (two for each unit, one required)
Type	Centrifugal submersible single stages
Seal	Mechanical
Capacity	40 gpm - 80 gpm
Head at rated capacity	115 ft
Design pressure	145 psig (minimum)
Design temperature	145°F (minimum)
Materials	
Pump casing	Aluminum or stainless steel
Shaft	Cast iron or stainless steel
Impeller	Cast iron or stainless steel
Incore Instrumentation Room Sump Pumps	
Number	2 (one for each unit)
Type	Vertical centrifugal single-stage
Motor horsepower	1.5 hp
Seal	Packing
Capacity	10 gpm
Head at rated capacity	40 ft
Design pressure	150 psig
Design temperature	350°F
Materials	
Pump casing	SS 304
Shaft	SS 304
Impeller	SS 304
Component cooling heat exchanger pit sump pump	
Number	1
Type	Vertical centrifugal single-stage
Motor horsepower	1 hp
Seal	Packing
Capacity	25 gpm
Head at rated capacity	44 ft
Design pressure	160 psig
Design temperature	180°F
Materials	
Pump casing	Cast iron
Shaft	Stainless Steel
Impeller	Bronze
Primary drains transfer pumps	
Number	4 (two for each unit, one required)
Type	Canned horizontal centrifugal
Motor horsepower	3 hp

Table 9.7-1 (CONTINUED)
VENT AND DRAIN SYSTEM COMPONENT DESIGN DATA

Seal	Canned pump	
Capacity	60 gpm	
Head at rated capacity	64 ft	
Design pressure	150 psig	
Design temperature	400°F	
Materials		
Pump casing	SS 316	
Shaft	SS 316	
Impeller	SS 316	
Loop drain header relief valve		
Number	2 (one for each unit)	
Capacity	1 gpm at 150 psig, 366°F	
Pressure setting	150 psig	
Design pressure	150 psig	
Design temperature	366°F	
Primary drain transfer tank relief valve		
Number	2 (one for each unit)	
Capacity	15 gpm at 150 psig, 366°F	
Pressure setting	150 psig	
Design pressure	150 psig	
Design temperature	366°F	
Primary drain cooler		
Number	2 (one for each unit)	
Total duty	5×10^6 Btu/hr	
	Shell	Tube
Design pressure	150 psig	200 psig
Design temperature	200°F	400°F
Operating pressure	100 psig	50 psig
Operating temperature, in/out	105/140°F	350/150°F
Material	Carbon steel	SS 304
Fluid	Component cooling water	Reactor coolant system drains
Design code	ASME III, Class C	ASME III, Class C
Vent and drain piping and valves		
Material	Stainless steel and carbon steel	
Design code	ANSI B31.1	
Design pressure	95 psig	
Design temperature	250°F	

Figure 9.7-1 (SHEET 1 OF 2)
PRIMARY VENT AND DRAIN SYSTEM

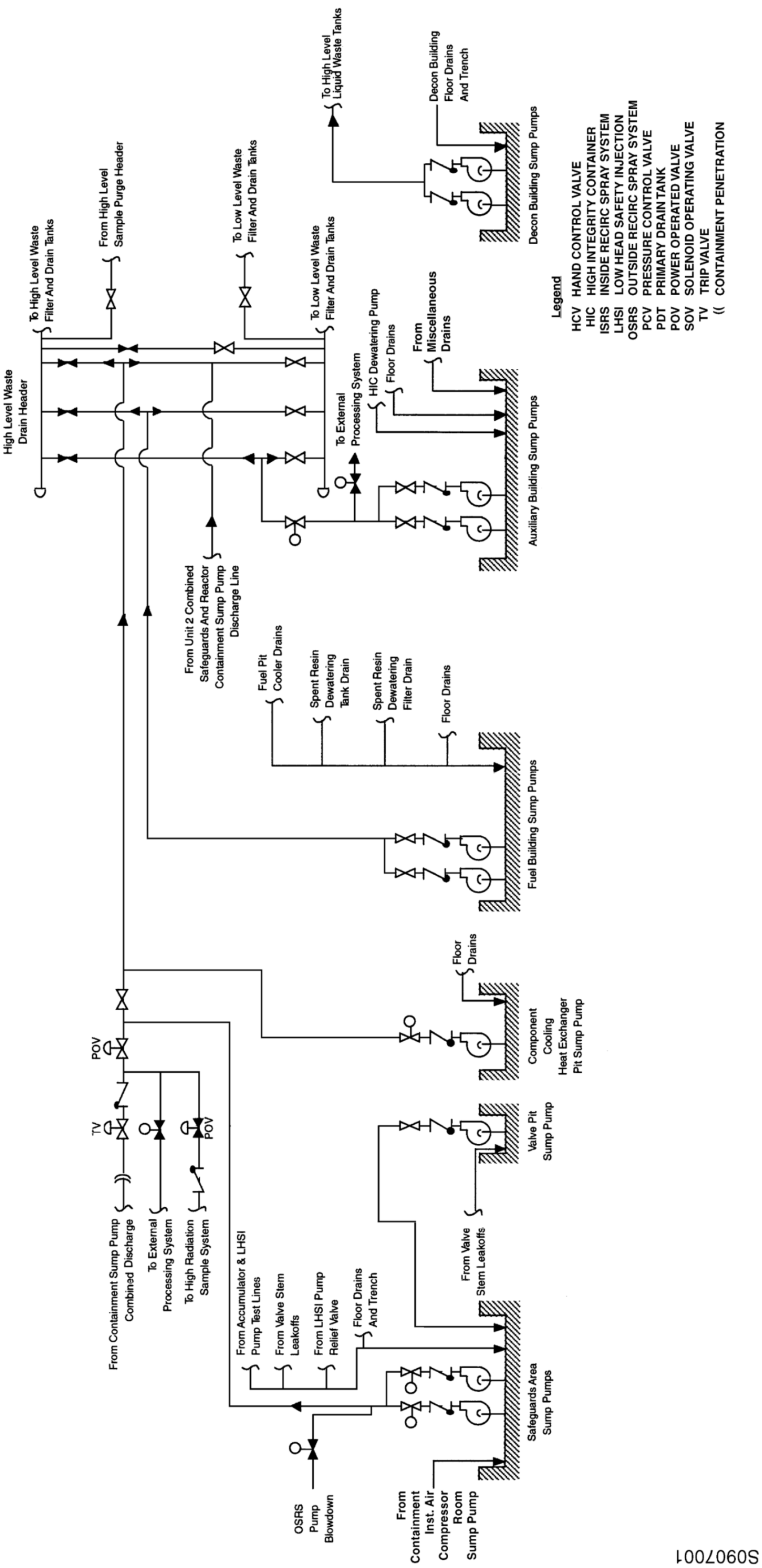
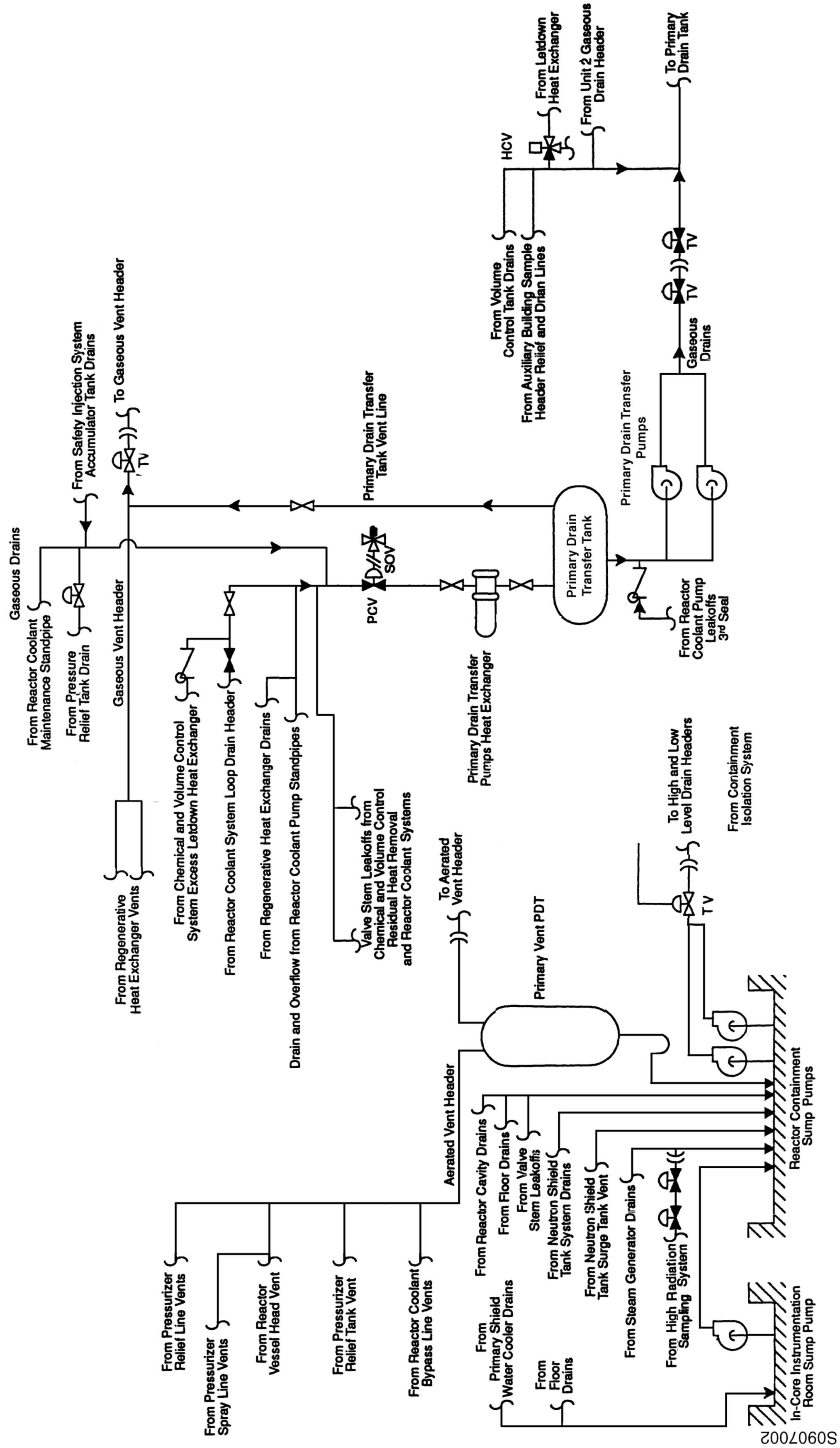


Figure 9.7-1 (SHEET 2 OF 2)
PRIMARY VENT AND DRAIN SYSTEM



9.8 COMPRESSED AIR SYSTEM

The compressed air system includes a service air subsystem, an instrument air subsystem, and a containment instrument air subsystem for each unit. Air service to certain common station areas may be provided from either unit.

9.8.1 Design Bases

The compressed air system is shown in Figure 9.8-1 and Reference Drawings 1 and 2. The design objective of the compressed air system is to ensure availability of sufficient quantities of compressed air of suitable quality and at the pressures required for station operation.

Design pressures are dictated by the expected uses of instrument or service air. Design temperatures are those resulting from extreme ambient conditions and are based on 105°F for the air cooled service air and instrument air compressors. The dew point of the instrument air is reduced by air driers. In the turbine building and low level subsystems, the air driers incorporate desiccants that reduce the pressure dew point to approximately -40°F or lower. This air is also provided to the Auxiliary Building and Condensate Polishing Building Subsystems. The containment building and subsystem incorporate refrigerant driers that reduce the pressure dew point to approximately +50°F. The lowest indoor temperature expected at the point of instrument air use is about +50°F everywhere other than containment. Inside of containment, the lowest expected temperature is higher.

Design data for components of the compressed air system are given in Table 9.8-1.

The compressed air system, compressors, air receivers, driers, piping, valves, and supports to critical instrument and controls are designed to provide reliable sources of compressed air. Portions of the subsystems (critical system components and designated containment isolation features) are designed to Seismic I Criteria (Table 15.2-1). Instrument air compressors function as backup sources of compressed air to the instrument air system and the containment instrument air subsystem and are connected to the emergency power system for greater availability of compressed air in the event off-site power is lost.

While the piping, compressors, and related equipment associated with the compressed air system are not required to operate during or following a design bases accident, air operated devices, both safety related and non-safety related, are designed to fail to a safe position on a loss of air to the device. The safety related air operated devices required to function after an accident are provided with backup air or nitrogen bottles to operate the devices for the complete loss of normal instrument air supply. The plant systems that have critical components which require safety related-dedicated air tanks are as follows: component cooling (Section 9.4.4.3), main steam/feedwater (Section 10.3.5.2), reactor coolant (Section 4.3.4.2), and ventilation vent systems (Section 5.3.1.3.4).

9.8.2 Description

The service air subsystem is equipped with three 100% capacity electric motor driven air compressors, operating at approximately 110 psig. The service air compressors are the primary source of compressed air to both the service air and instrument air subsystems including the condensate polishing building air system during normal station operation. These compressors are located outside on the south side of the turbine building. The service air subsystem also provides service air at hose connections in each unit for operating equipment and tools during normal operation and refueling.

The instrument air subsystem is used to provide air as required for instruments and controls associated with each unit outside containment, and are also available as a backup source of air for the containment instrument air subsystem. The instrument air subsystem is equipped with two (one per unit) 100% capacity electric motor driven air compressors, which operate at approximately 110 psig. The instrument air compressors are used to provide compressed air to the instrument air subsystem during loss of power events and to provide backup instrument air during normal station operation. These compressors are located in the turbine building in an area protected from tornadoes, missiles, and earthquakes.

The three service air compressors are connected to a common discharge header. This header simultaneously supplies compressed air to each of the two unit specific and the shared service air receivers. In addition, this header branches off and provides the source of compressed air to the Condensate Polishing Building. The shared diesel powered service air compressor is so connected as to supply compressed air to all three service air receivers.

The service air compressors are connected to a control system that provides for one of the three compressors to function in a “lead” capacity. In such a configuration, should the air header pressure fall below a predetermined value, the second or “lag” compressor will automatically start and restore header pressure. Should the “lead” and “lag” compressor be unable to restore header pressure the “lag-lag” compressor will start automatically to restore header pressure. The shared diesel powered service air compressor is manually started when needed.

Each instrument air receiver is directly connected to its unit specific service air receiver. In this manner the service air subsystem becomes the primary air source for the instrument air subsystem. Each instrument air receiver is isolated from its associated service air receiver by means of a check valve.

Each unit specific instrument air compressor is connected to its associated instrument air receiver. Each instrument air compressor is capable of automatically starting should its associated receiver pressure fall below a predetermined value. In this manner, the instrument air compressors provide a backup source of compressed air to the instrument air subsystem.

The compressors in both the service air and instrument air subsystems are classified as non-lubricated or oil free. The shared diesel powered service air compressor is of oil flooded screw design. This compressor has charcoal filters installed between the compressor and the service air subsystem piping. These filters prevent oil contamination of the compressed air piping systems.

The compressed air in both the service air and instrument air subsystems is filtered and dried. The compressed air in both the service air and instrument air subsystems is suitable for human consumption (breathing air).

The instrument air compressors and their driers are connected to the emergency power system (Section 8.5) so that continuous instrument air supply is ensured after a loss-of-power accident. The three electric motor driven service air compressors, one shared diesel engine driven service air compressor, and two instrument air compressors are air cooled.

Station instrument air and service air lines penetrating the containment structures are provided with normally closed manual shutoff valves located outside the containment to seal the containment internal atmosphere from the outside atmosphere during an accident. Instrument and service air line penetrations are isolated in accordance with Class V piping, as described in Section 5.2.

The containment instrument air normal supply line from the compressors and air dryers located outside containment, has a containment isolation trip valve outside containment and a check valve located inside containment. The suction line from the containment to the compressors has both an inside and outside containment isolation trip valve. The containment trip valve piping configuration is Class I, as described in Section 5.2 for containment isolation.

The equipment includes the conventional accessories, such as cylinder cooling systems, storage receivers, aftercoolers, and safety valves.

The containment instrument air subsystem consists of two water-sealed, rotary compressors and associated refrigerant air driers installed at the 11 ft. 6 in. elevation of the safeguards area buildings for Units 1 and 2. The compressors take a suction from the containment via a 3-inch penetration. Containment trip valves are provided on both sides of the penetration. Each compressor can provide a minimum of 19.6 scfm at 90 psig minimum. A shell and tube heat exchanger is provided on each compressor to cool the seal water. Cooling water for these heat exchangers comes from the component cooling water system. A connection to primary grade water is also provided for sealwater makeup. One compressor will be in continuous service and will automatically load or unload to meet system demand. The other compressor will be on standby and will start automatically if system pressure decreases to 90 psig.

Each compressor discharges to its own moisture separator and filter. Water removed from the air by the moisture separators and air driers is directed to a sump, where a small sump pump transfers the water to the liquid waste system. Each air compressor discharges to its own refrigerant air drier. The piping allows the air compressors to be cross-connected with the air driers as well as allowing them to bypass the driers completely. Air exiting the driers will have a dewpoint of about +50°F. The air will enter the containment through a containment trip valve tied into the turbine building control air cross-connect piping, using containment penetration 47.

Since the compressors process potentially contaminated air, an enclosure is provided around the air compressors, driers, and associated equipment. During normal operation, the enclosure air is ducted to and monitored for radioactivity prior to entering the ventilation vent number 2. During abnormal conditions, the enclosure exhaust ventilation dampers are closed on a safety injection signal, and the safeguards exhaust fans are subsequently tripped. In addition, during a DBA the containment instrument air subsystem is isolated by the containment isolation trip valves. The enclosure consists of sheet metal walls and roof. The floor of the enclosure is a poured concrete pad with integral sump and slopes toward the sump.

The compressors are powered from normal buses, since they are not required to operate during or following an accident.

Associated piping is designed in accordance with ANSI B31.1-1967. Design conditions are 150 psig and 150°F.

9.8.3 Design Evaluation

The following devices are provided to preserve an adequate instrument air supply under abnormal conditions, and to ensure system reliability:

1. High capacity service air compressors supply both service air and instrument air subsystems. If instrument air pressure falls, additional compressors may be automatically or manually started. Service air loads can be isolated from the main control room via solenoid operated valves. A bypass line is also provided from the outlet of each unit specific service air receiver to the inlet of its associated instrument air drier. In the event of failure of an instrument air receiver, compressed air may be directly supplied by the service air receiver. In addition, the instrument air compressors are supplied by the emergency bus for loss of off-site power events.

2. Alternate standby air sources are available. If the service air header pressure falls, the second or “lag” service air compressor will automatically start and restore header pressure. In the event that the “lead” and “lag” service air compressors are unable to restore service air header pressure, the “lag-lag” service air compressor will automatically start and restore header pressure. If the instrument air header pressure falls, the instrument air compressors automatically start and restore the instrument air subsystem pressure. Also, the shared, diesel-powered service air compressor can be manually started when needed.

3. Instrument air backup between the two units. This is provided by means of cross-connecting lines between the two units at the main headers.

4. Instrument air backup to containment instrument air subsystem. In the event of the loss of both containment instrument air compressors and receivers, containment instrument air can

be supplied from the instrument air system by opening the manually operated valves in the cross-connect line provided.

5. Compressed air backup system to each instrument air line leading to a Spent Fuel Pool (SFP) canal door seal (2 doors). In the event of loss of instrument air pressure to a SFP canal door seal, the compressed air system provides backup pressure to ensure that the seal remains inflated to prevent leakage from the SFP into the fuel transfer canal.

The containment instrument air system is non-safety-related because the components requiring containment instrument air are not necessary for safe shutdown. The majority of loads on this system are spring-diaphragm-type air-operated valves, which use spring force to maintain the valves in a fail-safe condition. The remaining loads are the personnel airlock inner-door locking device and the reactor head inflatable seal in the head storage area. The compressors, accessories, and piping upstream from the first containment isolation valve and associated pipe support outside containment are not seismically qualified.

9.8.4 Tests and Inspections

Testing of the compressed air subsystems consists of air quality tests and compressor tests. Air quality is monitored through surveillance procedures that ensure air hydrocarbon content, particulate content, and dew point meet acceptable standards. Generally, compressor tests are conducted at refueling, with the exception of a more frequent test of the instrument air compressor. Preventive maintenance and inspection of the systems is performed in accordance with normal station maintenance procedures.

9.8 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-075A	Flow/Valve Operating Numbers Diagram: Compressed Air System, Unit 1
2.	11548-FM-25A	Flow Diagram: Compressed Air System, Unit 2

Table 9.8-1
COMPRESSED AIR SYSTEM DESIGN DATA

Service Air Subsystem

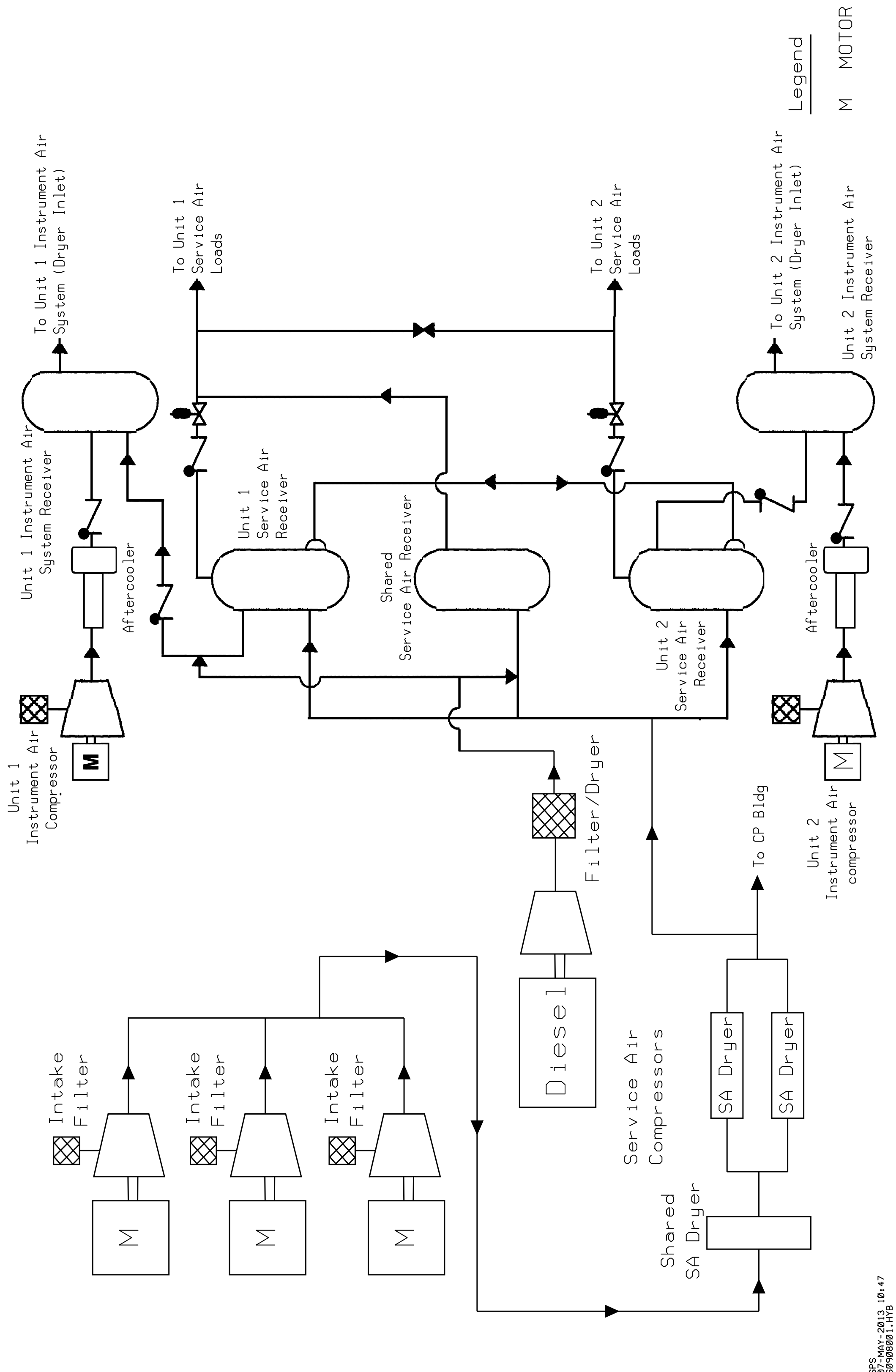
Service Air Compressors	
Number	4 (3 motor driven, 1 diesel driven)
Discharge Pressure	110 psig
Discharge Temperature	120°F (unit specific)
Discharge Temperature	150°F (shared)
Capacity	750 scfm, diesel driven 1070 ACFM, motor driven
Service Air Receivers	
Number	4 (2 unit specific, 2 shared)
Design Press/Temp	125 psig @ 400°F (unit specific)
Design Press/Temp	125 psig @ 500°F (shared) - carbon steel 150 psig @ 450°F (shared) - stainless steel
Volume	77.1 ft^3 (unit specific)
Volume	678.6 ft^3 (shared) - carbon steel 141 ft^3 (shared) - stainless steel
Operating Pressure	110 psig
Operating Temperature	120°F
Material	Stainless Steel (Unit 1) and shared stainless steel
Material	Carbon steel (Unit 2 and shared carbon steel)
Design code	ASME VIII
Instrument Air Compressors	
Number	2 (one for each unit)
Discharge pressure	110 psig
Discharge temperature	120°F
Capacity	411 scfm
Instrument Air receivers	
Number	2 (one for each unit)
Volume	77.1 ft^3
Design pressure	125 psig
Design temperature	400°F
Operating pressure	110 psig
Operating temperature	120°F
Material	Carbon steel
Design code	ASME VIII

Table 9.8-1 (CONTINUED)
COMPRESSED AIR SYSTEM DESIGN DATA

Service Air Subsystem (continued)	
Instrument Air Dehydrators	
Number	2 (one for each unit)
Capacity	650 scfm
Dewpoint at 100 psig	-40°F
Type	Desiccant
Containment Instrument Air Subsystems	
Containment Instrument Air Compressors	
Number	4 (two for each unit)
Discharge pressure	95.3 psig (Nominal)
Capacity	30 scfm (Nominal)
Compressor motor	40 hp
Containment Instrument Air Receivers	
Number	4 (two for each unit)
Volume	34 ft^3
Design pressure	200 psig
Design temperature	450°F
Operating pressure	100 psig
Operating temperature	130°F
Material	Carbon steel
Design code	ASME VIII
Containment Instrument Air Driers	
Number	4 (two for each unit)
Capacity	45 scfm
Dewpoint at 100 psig	50°F [a]
Particulate count	< 20 μm
Type	Refrigerant
Service Air Driers	
Number	2
Capacity	1050 scfm @ 120°F
Dewpoint	-40°F
Compressed Air System Piping and Valves	
Materials	Carbon steel, stainless steel, copper and bronze
Design code	USAS B31.1

a. Since the containment operates under a vacuum, an exception is permitted to the ISA dewpoint standard by NRC's review correspondence of March 25, 1993 by which a dewpoint temperature of 50°F is acceptable.

Figure 9.8-1
COMPRESSED AIR SYSTEM



9.9 SERVICE WATER SYSTEM

River water is the source of service water for the Surry Power Station. Since this water is brackish, it is not directly used for cooling critical equipment. Service water is used as cooling water for heat exchangers that remove heat from the component cooling water system (Section 9.4), the bearing cooling water system (Section 10.3.9), the recirculation spray system (Section 6.3.1), charging pump service water subsystem (Section 9.9.2.1), and other station applications such as air conditioning and chilled water. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the service water system was found to be adequate.

The service water system is shown in Figure 9.9-1 and Reference Drawings 1 through 4.

9.9.1 Design Bases

The service water system is designed for the removal of heat resulting from the simultaneous operation of various systems and components of two units based on a maximum river water temperature of 100°F. Component capacities with a SW inlet temperature of 95°F shown in Table 9.4-1 for Component Cooling Heat Exchanger, Table 9.4-2 for Chilled Water System and Table 9.9-3 for Charging Pump reflect the design rating of the equipment. A Service Water temperature of 95°F was assumed for equipment specifications. This equipment will function acceptably with a slightly reduced capacity at a maximum river water temperature of 100°F. This temperature is 7°F warmer than river model tests indicate for the river water temperature on record (Reference 1). The service water system is designed as a Class I system (Section 15.2.4).

The charging pump cooling water system consists of two separate subsystems: a component cooling water subsystem and a service water subsystem. The charging pump component cooling water system is described in Section 9.4.3.5.

A separate charging pump service water system is provided for each reactor unit. The charging pump service water system is designed to provide cooling water from the service water system to the charging pump intermediate seal coolers and to the charging pump lubricating oil coolers. Charging pump service water system component design data is given in Table 9.9-3. A more detailed system description is given in Section 9.9.2.1. The charging pump service water system is designed as Class I (Section 15.2.1).

9.9.1.1 **Accident Design Bases**

During a LOCA without a loss of station power, the supply and discharge isolation valves to the recirculation spray heat exchangers open in the affected unit. All valves in the service water supply to the other heat exchangers will remain open. During this type of accident, the service water requirements will increase above those listed under Section 9.9.2 and include the flow to the recirculation heat exchangers, which is given in Table 9.9-2.

If a total loss of station power occurs simultaneously with a LOCA in either unit, the recirculation spray heat exchanger supply and discharge isolation valves open and all other isolation valves in the service water system of the LOCA affected unit are closed. Under these conditions the service water flow to the recirculation spray heat exchangers will be at least 12,280 gpm and vary as a function of the intake canal level.

In the event of a total loss of station power only, the recirculation spray heat exchanger supply and discharge isolation valves remain closed and all other service water isolation valves remain open.

The operation of condenser and service water valves under accident conditions and various other events is described in Table 9.9-1.

9.9.1.2 **Emergency Service Water Pumps**

In the event of a loss of station power at the river intake, three diesel-driven, vertical emergency service water pumps have been provided for both units at the river intake structure to supply makeup to the high-level canal. The pumps are sized to provide the design required make-up to the intake canal with the James River at design low water level (i.e., maximum expected developed head).

The following criteria were used in sizing the emergency service water pumps:

1. In the event of a LOCA and a total loss of station power, with the requirement that the unit that did not undergo the LOCA must also be cooled down, water flow is required to the recirculation spray heat exchangers, component cooling heat exchangers, other miscellaneous loads, and make-up for various non-cooling related high level canal inventory losses. This would require two of the three pumps to be operated.
2. In the event of a design-basis accident (LOCA in either unit and a total loss of station power), water flow is required to the recirculation spray heat exchangers, component cooling heat exchangers, other miscellaneous loads, and make-up for various non-cooling related high level canal inventory losses. This condition, assuming one unit is in cold shutdown and the heat load from the shut down unit and spent fuel is less than 25 million BTU/Hr, would require one emergency service water pump in operation.
3. In the event of a loss of station power in two units, component cooling heat exchangers would be required to cool down the units. Additional flow would be required for other miscellaneous loads and make-up for various non-cooling related high level canal inventory losses. This would require two of the three pumps to be operated.

9.9.1.3 **System Operation During Design Basis Hurricane**

A Probable Maximum Hurricane (PMH), as described in Section 2.3.1.2.2, will result in reduced available service water flow due to the decreased driving head across the gravity flow service water system. The driving head will be reduced since the river level, to which the service water flow path discharges, will be higher due to storm surge. The revised design basis PMH analysis documents the adequacy of the Service Water System to maintain the units in a safe intermediate shutdown condition by removing decay heat concurrent with the loss of off site power. The design basis PMH analysis requires that operating units be brought to intermediate shutdown prior to the hurricane reaching the site and subsequently maintaining RCS temperature below 350°F. Units at cold shutdown or in refueling would be maintained at either cold or intermediate shutdown with RCS temperature below 350°F. Refueling activities would be suspended prior to the arrival of the hurricane. In accordance with design basis criteria, a design basis accident (LOCA) is not considered during the PMH (Reference 2).

Prior to arrival of the hurricane, site procedures require the start of hurricane preparations such as closing missile doors, putting flood protection barriers in place, and preparing equipment required for shutdown. Emergency service water (ESW) pump house door seal plates and louver opening covers will be procedurally installed.

With both units operating prior to the hurricane, the units are to be shut down two hours before the hurricane reaches the site. Decay heat will be removed using the circulating water/service water system until a loss of power occurs after which the auxiliary feedwater system will be used. For analysis basis, this is assumed to be 2 hours after the plant has shut down (i.e., the loss of power occurs coincident with the arrival of hurricane winds on site). This criteria is consistent with the guidelines provided in NUMARC 87-00 (Section 2.11, *Hurricane Preparations*) (Reference 3).

The water elevation in the Intake Canal will be established at 28-30 feet to ensure that sufficient driving head is available to provide heat removal capability for the Component Cooling System during the expected storm surge. Reanalysis of the wave run-up within the intake canal indicates a freeboard of 4 feet from the top of the canal (Elevation 36 ft.) is required. Therefore, a canal elevation of approximately 28-30 feet is within the requirements of the wave run-up analysis.

Due to the potential for the intake canal siphoning back through the circulating water pump discharge lines, the circulating water pumps will be shut down prior to the hurricane reaching the site. The plant has been modified to break the siphon at Elevation 23 ft., however, the hurricane analysis required an elevation of 28 feet to ensure adequate service water flows with peak river surge. Therefore, the circulating water pumps will be shut down and the siphon broken after raising the canal level to at least 28 feet.

To ensure adequate decay heat removal of the shutdown unit(s) at the peak river surge (Elevation 22.7 ft.), the CCW heat exchangers and pumps will be cross-connected to allow the flow of the CCW pumps to be equally distributed to three CCW heat exchangers. Also, to minimize the CCW heat loads, all nonessential heat loads will be isolated. The analysis is based on using CCW for decay heat removal (using the RHR heat exchangers) for the cold shutdown unit(s), and CCW for heat removal for letdown and auxiliary feedwater for decay heat removal for the intermediate shutdown unit(s).

For the case where one unit was initially operating and one unit was at cold shutdown, an additional 60,000 gallons of AFW is available for the operating unit. This additional 60,000 gallons will allow AFW operation for 39 hours after shutdown of the circulating water system. The decay heat load analysis is based on the operating unit(s) being shut down 2 hours prior to the hurricane reaching the site and loss of power occurs. However, in order to ensure that a canal level of 28 feet is established and isolation of the circulating water system occurs without siphoning the canal, the operating unit will be shut down by procedures before hurricane wind speed is reached to enable operators to verify that the active vacuum breakers on the circulating water discharge piping have opened. This operator action will be carried out at the low level intake to ensure isolation of the canal and no siphoning prior to high winds and high river elevation.

For less severe hurricane conditions characterized by storm tides at the Surry site less than or equal to 8.0 feet, adequate head for the service water system will remain available for cooling the component cooling system without performing some special actions. A storm tide of 8.0 feet is equivalent to the effective CW/SW discharge elevation with an unprimed CW discharge tunnel. Therefore, securing the CW pumps, and breaking the siphon prior to arrival of the hurricane are not necessary to ensure adequate intake canal inventory remains available. Similarly, advance re-alignment of the CCW system and isolation of non-essential loads also are not required to be performed.

9.9.2 Description

Service water is supplied from the circulating water system (Section 10.3.4) by gravity flow between the high-level intake canal and discharge canal seal pit. During normal operation, the water level in the intake canal is approximately 28 feet above the level in the seal pit at the discharge canal. This differential head supplies the service water to parallel flow paths through the bearing cooling water heat exchangers, component cooling heat exchangers, and recirculation spray heat exchangers, which are also in parallel with the main condenser. Service water is also supplied to the control room and relay room air conditioning system chiller condensers, charging pump lubricating oil coolers, and to the charging pump cooling water system intermediate seal coolers.

Remotely operated butterfly valves are installed at the four inlets and outlets of each main condenser and in the supply lines to the bearing cooling water heat exchangers and the component cooling heat exchangers. For the recirculation spray heat exchangers remotely operated butterfly valves are installed in the supply and discharge lines to each cooler in addition to the supply valves associated with each service water supply header. The operation of these valves is listed in Table 9.9-1. These motor-operated valves are positioned automatically for various accident conditions to conserve water in the intake canal for critical services. Power for these valves is from the station emergency 480V motor control centers.

To minimize the potential for macrofouling and to facilitate venting of the recirculation spray heat exchangers during the initial inrush of water, a portion of the service water supply lines to the heat exchangers is maintained in wet layup and chemically treated during normal operation. The section of pipe to be maintained in layup begins downstream of valves SW-MOV-103/203, A, B, C, and D and extends to the four 24-inch supply line tie-ins off the 36-inch service water supply header. The water maintained in these lines is chemically treated to prohibit marine growth. In addition, the service water supply to the component cooling heat exchangers is also chemically treated to reduce biofouling of the heat exchangers.

Service water is supplied to the cooling water subsystem of the control room and relay room air conditioning system chiller condensers and to the charging pump service water subsystem from three separate circulating water lines through three independent flow paths. The three flow paths provide the operating flexibility to remove a flow path from service for cleaning without entering into a Technical Specification limiting condition for operation.

A temporary service water flow path may be provided to perform maintenance on the single service water supply to the component cooling heat exchangers. Use of the temporary flow path must be in accordance with an approved temporary change to Technical Specifications and an associated license condition. The piping is routed through the turbine building basement from the circulating water inlet piping to the supply piping of two of the component cooling heat exchangers. The temporary service water supply is used only during a Unit 1 outage.

Trash racks have been installed to prevent large pieces of trash from entering the intake structure which could adversely affect the operation of the emergency service water pumps. Since each bay of the intake structure is sized for a total flow of 220,000 gpm and each emergency service water pump is assumed to deliver a minimum of approximately 14,000 gpm, sufficient water will be provided to the emergency service water pumps as long as approximately 7.5% of the flow area of the racks remains clear.

In the event of a power failure simultaneous with the accumulation of trash at the trash racks, accumulated trash can be removed from the screens of the station intake by manual raking. This procedure could be done indefinitely if necessary although it is expected that the duration of the loss of power would be relatively short, i.e., less than 1 week.

The maximum service water requirements of the system during normal operation are given in Table 9.9-2.

9.9.2.1 **Charging Pump Service Water System Description**

A charging pump service water system for each reactor unit provides water to cool the charging pump intermediate seal coolers and the charging pump lubricating oil coolers.

Either of two 100%-capacity charging pump service water pumps delivers water from the service water system to the charging pump intermediate seal coolers and the charging pump lubricating oil coolers, thereby maintaining the charging pump lubricating oil and the component cooling water used to cool the charging pump mechanical seals at the proper temperature. To ensure that service water is continually available, one pump is in operation and the other on standby. The standby pump is automatically actuated on low pump discharge pressure to supply service water in the event of failure of the operating pump.

The two redundant 100%-capacity charging pump service water pumps are separated by seismic, missile-protected, 3-hour fire rated walls, ceiling, and floor. An automatic actuating fire safe isolation ball valve is installed in the cross-connect piping between the two pump trains. The separation and cross-connect of the two redundant pump trains is designed to meet the requirements stipulated in Appendix R, Section III.L.2(e), of 10 CFR 50.

The installation of two full-capacity charging pump service water pumps provides 100% redundancy for this cooling water system. All components of the charging pump service water system, including pumps and heat exchangers are designed to Seismic Class I criteria.

The charging pump service water pumps are connected to the emergency electrical bus to ensure that they will operate in the event of a loss of station power.

Regulatory Guide 1.97 requirements for post-accident monitoring of charging pump service water system status are satisfied by flow and temperature measurement at the discharge of each charging pump service water pump. Flow and temperature transmitters are environmentally and seismically qualified in accordance with IEEE 323-1974 and IEEE 344-1975 respectively. Control room display is provided through the NUREG 0696 multiplexing system.

9.9.3 Design Evaluation

The following components of the auxiliary cooling systems are required for performance of the engineered safety features:

MOV-SW-103A, B, C, & D	Motor-operated valves that admit SW to the RS coolers SW supply header.
MOV-SW-104A, B, C, & D	Motor-operated valves that admit service water to the recirculation spray coolers.
MOV-SW-105A, B, C, & D	Motor-operated valves that discharge service water from the recirculation spray coolers.
MOV-CW-106A, B, C, & D	Motor-operated valves that stop water flow to the main condenser.
MOV-CW-100A, B, C, & D	Motor-operated valves that stop water flow from the main condenser discharge

MOV-SW-102A & B	Motor-operated valves that stop service water to component cooling water heat exchangers.
MOV-SW-101A & B	Motor-operated valves that stop service water to the bearing cooling water heat exchangers.
SW-P-10A & B	Charging pump service water pumps to supply cooling water to the charging pump cooling water system.
CC-P-2A & B	Charging pump cooling water pumps that circulate the component cooling water of the charging pump cooling water system.
1-CW-LS-102 &103	Canal level switches which provide a signal to isolate non-essential flows from the intake canal.
2-CW-LS-202 & 203	Canal level switches which provide a signal to isolate non-essential flows from the intake canal.

The associated instrumentation and power systems for the operation of these components are redundant, and have protected power and control circuits in conformance to IEEE-279 and 10 CFR 50, General Design Criteria.

The components themselves are redundant except for motor-operated valves MOV-SW-102A & B and MOV-SW-101A & B, which stop service water to the component cooling water heat exchangers and the bearing cooling water heat exchangers. Motor-operated valves MOV-SW-102A & B are in parallel pipelines, as are motor operated valves MOV-SW-101A & B. Failure of one of these valves will allow service water to escape from the service water canal through the component cooling water heat exchangers or the bearing cooling water heat exchangers. However, in the event of failure of one of these motor-operated valves, manual valves that are accessible immediately following a design-basis accident are provided to isolate the service water pipelines to the bearing cooling water heat exchangers and the component cooling heat exchangers, thereby conserving water in the intake canal for the recirculation spray coolers.

In the event of the design-basis accident, the valves in the supply lines to the component cooling heat exchangers may be reopened remote-manually from the control room, provided low canal level setpoint has not been reached, if service water to this system is considered necessary.

Automatic temperature control of the charging pump lube-oil systems is provided by the use of air-operated control valves. These valves are installed in the service water outlet of each lube-oil cooler. Capillary type thermal elements are installed in the oil lines which provide the signal to a pneumatic-indicating temperature controller with the output signal operating the control valve.

The piping and equipment movements at the recirculation spray heat exchangers have been analyzed in accordance with earthquake design criteria and have been installed to ensure that no undue forces are exerted on piping or equipment nozzles.

The gravity flow of service water from the intake canal ensures adequate cooling water to the recirculation spray heat exchangers and other essential loads in the case of the design-basis accident. This supply of cooling water is based on service water flow through recirculation spray heat exchangers, component cooling heat exchangers, and miscellaneous loads that include control room chiller condensers and charging pump coolers. Depending on the initial conditions and the single failure assumed, one or more emergency service water pumps are required to assist in maintaining the intake canal inventory within design limits.

A diesel fuel-oil storage tank provides sufficient fuel to operate three emergency service water (ESW) pumps for 24 hours and two for an additional 72 hours. Diesel operation for all three ESW pumps is locally controlled. Canal inventory calculations consider pump operation by diesel drive following a loss of offsite power.

The possibility of leakage from the reactor containment into the service water through the recirculation spray heat exchangers after a LOCA is discussed in Section 6.3.1.

9.9.3.1 **System Reliability**

A double set of normally closed parallel motor-operated butterfly valves control the service water supply to the recirculation spray service water headers. The heat exchanger inlet and outlet valves are closed during normal plant operation to prevent service water inleakage, which could cause tube fouling. These service water valves are opened in response to a Consequence Limiting Safeguards (CLS) hi-hi containment pressure signal. Each individual valve has a CLS activated relay in its opening circuit to open the valves in the event of a design basis accident. The double set of parallel butterfly valves assure that service water will always be provided to the recirculation spray service water header in the event of a malfunctioning valve. Malfunction of a single heat exchanger inlet or outlet valve will result in isolation of service water to only one heat exchanger as discussed in Section 9.9.3.2.

Three diesel-driven emergency service water pumps are furnished to provide makeup to the intake canal during a loss of offsite power. Batteries provide the power required to start and shutdown the diesels and to monitor diesel status. Battery chargers, fed from normal station power, are used to maintain the batteries in a fully charged condition. The three diesels are also each equipped with an alternator capable of carrying running loads and maintaining a float charge on the starting batteries during extended operation of the diesels. Safety-related blocking diodes are provided to isolate the safety related batteries from the non-safety related battery chargers.

9.9.3.2 **Malfunction Analysis**

Failure of the service water system is precluded as follows:

1. Malfunction of the butterfly valves in supply lines to recirculation spray service water headers is accommodated by a double set of valves in parallel to ensure that water will be available at all times.
2. Malfunction of either a recirculation spray heat exchanger inlet or outlet isolation valve upon receipt of a CLS hi-hi signal will result in isolation of service water to a single recirculation spray heat exchanger. Loss of one heat exchanger will not prevent mitigation of the design basis accident since only two recirculation spray heat exchangers are required (minimum safeguards).
3. Failure to restore power to circulating water pumps is accommodated by three diesel-engine-driven emergency service water pumps. One or more pumps are required to operate, depending on the particular event or single failure assumed, to supply water to control any of the accidents or events listed in Table 9.9-1.

The charging pump service water system cannot be disabled totally by a single passive failure. With the exception of the single discharge header common to both units, the system has been designed with cross-connect piping and sufficient valves so that any single passive failure can be isolated as necessary to allow the system to continue to operate and provide cooling water to support operation of at least two charging pumps. If a passive failure of the seismically qualified discharge header occurs, the system can still fulfill its safety-related design basis function without requiring operator action. In the redundant portions of the system, the isolation of a single passive failure and re-arrangement to continue to provide cooling water must be performed manually by the plant operators. In addition, the standby charging pump may have to be placed in operation, since isolation of the single passive failure might prevent cooling water from reaching the operating charging pumps. The complete system is expected to be accessible during an accident; however, if the course of an accident were to result in gross fuel failure, the local area radiological dose rates may substantially restrict access. For this situation, acceptable operation of the charging pump service water system can continue without isolation of credible passive failures.

9.9.4 Tests and Inspections

Periodic testing confirms that proper operation and safety signal actuation of the service water system valves in the lines supplying the recirculation spray heat exchangers is maintained.

The design head capacity characteristics of the service water system were verified by determining flows through the recirculation spray heat exchangers during initial start-up testing and subsequent special tests.

The diesel-driven emergency service water pumps are tested in accordance with the station’s Inservice Testing Program to ensure availability when needed. In addition, one diesel-driven pump is operated during tornado warning periods or at any time when it is thought that the backup operation of this pump materially contributes to the safety of the station.

The starting batteries, alternators, and blocking diodes for the diesels are periodically checked. The batteries are checked for specific gravity and voltage. Over a period of time, these tests will indicate weak or weakening trends in any cell, and replacement will be made, as necessary. In addition, the batteries are replaced per manufacturer's recommendation on a fixed maintenance schedule. The alternators are checked to ensure their ability to maintain a float charge on the starting batteries. The blocking diodes are checked to ensure current blockage and pass through capability has not been impaired.

9.9 REFERENCES

1. *Hydrology of the James River Estuary with Emphasis upon the Ten-Mile Segment Centered on Hog Point, Virginia*, A report Prepared for Virginia Electric and Power Company, Richmond, Virginia, As Supporting Material for the Preliminary Safety Analysis Report Surry Nuclear Power Station, Pritchard-Carpenter, Consultants.
2. Nuclear Regulatory Commission Letter, Serial #88-790, *Service Water System Design at Surry, Units 1 and 2,* dated 11/21/88.
3. *NUMARC 87-00, Rev. 1, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors,* dated August 1991.
4. Stone & Webster Engineering Corporation Calculation. 149378000, M-4, Rev. 2, *Extreme Weather/Hurricane Shutdown Analysis of Service Water Profile and Heat Transfer Capabilities*.

9.9 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-071A	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 1
	11548-FM-071A	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 2
2.	11448-FM-071B	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 1
	11548-FM-071B	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 2
3.	11448-FM-071C	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 1
4.	11448-FM-071D	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 1

Table 9.9-1
AUTOMATIC OPERATION OF CONDENSER AND SERVICE WATER VALVES

	Initial Valve Action	
Accident or Event	Service Water Valve	Main Condenser Valves
Loss of coolant, either unit, and total loss of offsite power (design-basis accident)	a. Open recirculation spray heat exchangers [a] to the affected unit	Close all valves on affected unit/throttle outlet valve on unaffected unit
	b. Close all others on affected unit/unaffected unit remains as-is	
Loss of coolant, either unit, without a loss of power to the affected unit [b]	a. Open recirculation spray heat exchangers [a] to the affected unit	All valves remain as-is both units
	b. All others remain as-is	
Total loss of offsite power	a. All valves remain as-is	Throttle outlet valves, both units
Loss of intake canal level	a. Recirculation spray heat exchangers [a] remain as-is	Close all valves, both units
	b. Close all others, both units	

a. Recirculation spray heat exchangers valves include SW inlet and outlet to each heat exchanger and SW supply from CW system.
b. A loss of power to the unaffected unit will cause the condenser outlet valves for that unit to throttle.

Table 9.9-2
SERVICE WATER REQUIREMENTS

	Flow gpm	Heat Transfer 10^6Btu/hr	No. of Exchangers Operating	No. of Exchangers Furnished
I. Normal Operation				
Component Cooling System[a]	18,000	100.6	2 (one for each unit)	4 (two for each unit)
Bearing Cooling System	48,000	144	4 (two for each unit)	6 (three for each unit)
Control Room Air Conditioning	501 [b]	1.94	2 (one for each unit)	5
Charging Pump:				
Lube-Oil Coolers	10 [c]	-	2 (one for each unit)	6 (three for each unit)
Intermediate Seal Coolers	20 [c]	-	4 (two for each unit)	4 (two for each unit)
II. LOCA Conditions				
Recirculation Spray System	12,280[d]	300 [e]	4 [f](four for each accident unit)	8 (four for each unit)
Component Cooling System	[g]		2 (non-accident unit)	4 (non-accident)
Control Room Air Conditioning	501 [b]	1.94	2 (one for each unit)	5
Charging Pump:				
Lube-Oil Coolers	20 [c]	-	4 [h]	6 (three for each unit)
Intermediate Seal Coolers	20 [c]	-	4 (two for each unit)	4 (two for each unit)

a. Flow and heat transfer rates are based on 2 heat exchangers operating at conditions appearing on the vendor data sheet. Typically, 4 CCHXs are aligned with throttled service water flow, as required to maintain component cooling supply temperature within design limits.

b. Peak flow required for design maximum load. Actual flow will normally be less and vary seasonally. A nominal 60 gpm service water flow rate is also supplied for backwashing the supply side strainers.

c. Flow rates are based on satisfying heat duty requirements. Actual flow rates on some coolers will be higher due to unbalanced parallel flow paths.

d. During a LOCA with a LOOP four RSHXs on the accident unit will initially operate, but only two RSHXs are required. Flow rate stated is based on 2 heat exchangers operating at an intake canal elevation of 17.2 feet. Actual flow rates will vary as a function of the intake canal level.

e. Heat transfer is based on a total of 2 heat exchangers operating (minimum ESF). Actual heat transfer rate will vary, depending on the time after accident initiation. Due to the time dependent SW flow rates through the heat exchangers, the heat transfer rate stated is not coincident with the indicated flow.

f. The maximum number of heat exchangers that can be operating at any given time is 4, which is based on the design basis event.

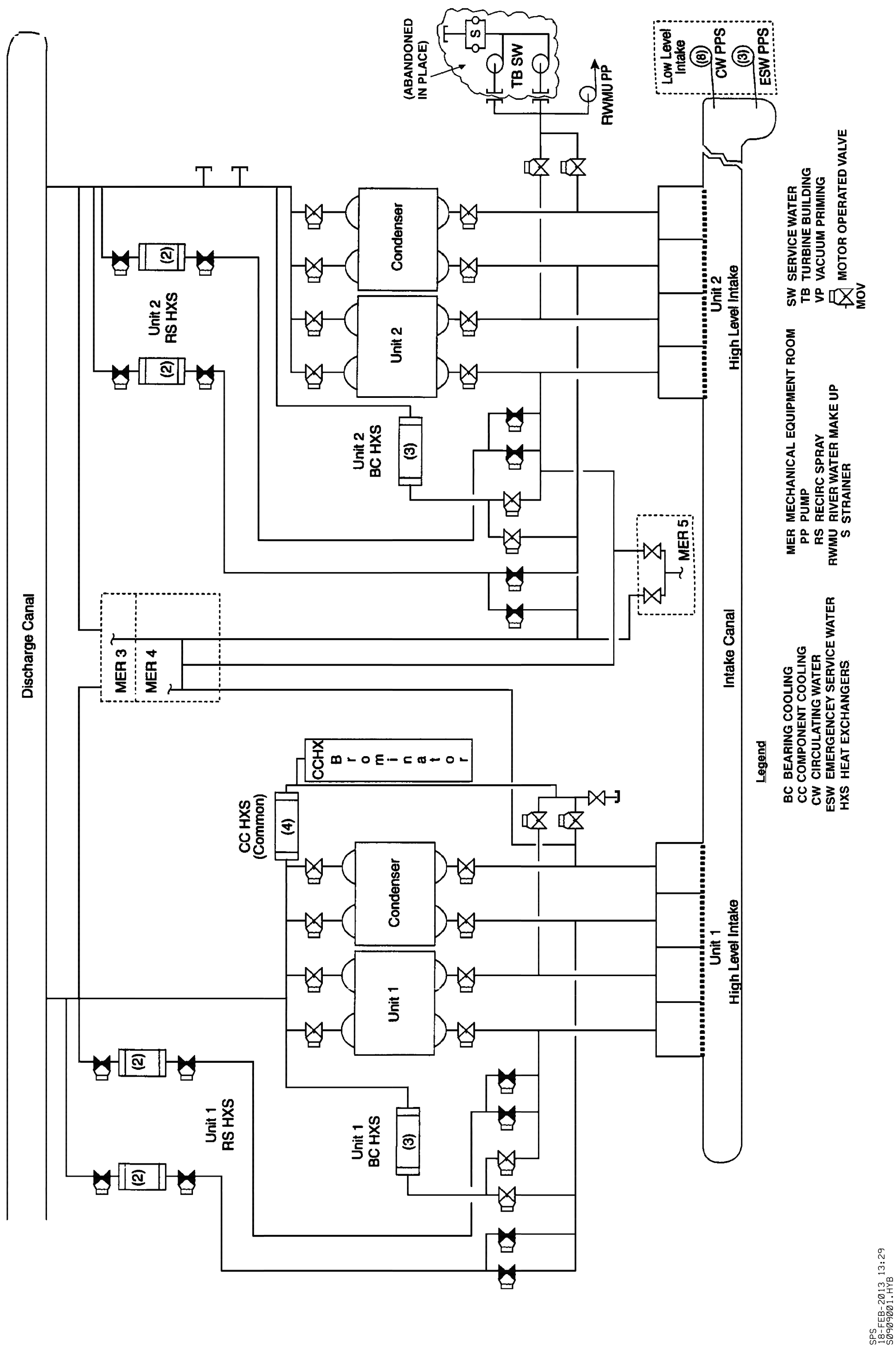
g. Depending on the initial conditions and the elapsed time after an accident, one or two CCHXs may be in service with throttled SW flow.

h. Three lube oil coolers are in service for the accident unit with one cooler in service for the non-accident unit.

Table 9.9-3
CHARGING PUMP SERVICE WATER SYSTEM

Charging pump service water		
Number	2 per unit	
Type	Centrifugal, in-line, single-stage	
Motor horsepower	7.5 hp	
Seal	Single Mechanical	
Capacity	90 gpm	
Head at rated capacity	60 ft	
Design pressure	150 psig	
Design temperature	250°F	
Materials		
Pump casing	316 Stainless Steel	
Shaft	316 Stainless Steel	
Impeller	316 Stainless Steel	
Charging pump intermediate seal cooler		
Number	2 per unit	
Duty, each	44,546.9 Btu/hr	
	Shell	Tube
Design pressure	56 psig	200 psig
Design temperature	150°F	350°F
Operating pressure	25 psig	40 psig
Operating temperature, in/out	106/105°F	95/97°F
Material	Cast Iron	70/30 Copper-Nickel
Fluid	Component Cooling Water	Service Water
Design Code	ASME Section VIII	ASME Section VIII

Figure 9.9-1
SERVICE WATER SYSTEM



Intentionally Blank

9.10 FIRE PROTECTION

9.10.1 Design Bases

The basic regulatory criterion for fire protection is set forth in 10 CFR 50, Appendix A, General Design Criterion 3. The station's fire protection program for Surry Power Station satisfies the regulatory criteria set forth in General Design Criterion 3, in 10 CFR 50 Appendix R (Sections III.G, III.J, III.L and III.O), and in Appendix A to Branch Technical Position APCSB 9.5-1 dated August 23, 1976.

Compliance with these criteria is contained in the following documents:

1. *10 CFR 50 Appendix R Report, Surry Power Station, Units 1 and 2* includes the description of systems, equipment, and manpower required for safe shutdown (Chapters 3, 5); the fire hazards analysis (Chapters 2, 4, 8); major commitments that form the basis for the fire protection program (Chapters 1, 6); engineering evaluations and exemption requests from Appendix R (Chapter 7); and the safe shutdown circuit analysis (Chapter 9).
2. *Fire Protection Program* document and the associated Administrative Procedures describe the administrative and technical controls, the organization, and other plant features associated with fire protection.
3. NRC's *Fire Protection Safety Evaluation Report, Surry Power Station, Units 1 and 2,* dated 9/19/79.
4. NRC's Safety Evaluation Report for Sections III.G and III.L of Appendix R, dated 12/4/81, and Supplemental Safety Evaluation Report, dated 11/18/82.
5. NRC's *Safety Evaluation by the Office of Nuclear Reactor Regulation Relative to Appendix R Exemptions Requested,* Surry Power Station, Units 1 and 2, transmitted by letter dated 2/25/88.
6. NRC's *Safety Evaluation by the Office of Nuclear Reactor Regulation, Surry Power Station, Units 1 & 2, Post-Fire Safe Shutdown Evaluation, Appendix R,* July 23, 1992.

Changes to the 10 CFR 50 Appendix R Report and Administrative Procedures are evaluated in accordance with 10 CFR 50.48. Consistent with the facility operating license, changes to these documents may be made without prior approval of the Nuclear Regulatory Commission provided the change does not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. The acceptance criteria for this assessment are that (a) the level of fire protection is not being diminished, and (b) the change will not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. If this acceptance criteria is met, then the revision is made.

The Surry fire protection program is intended to satisfy the basis regulatory criterion by meeting the following objectives, given the actual plant relationship between combustibles, safety-related equipment, and fire protection features:

1. Reduce the likelihood of fires.
2. Promptly detect and extinguish fires that do occur.
3. Maintain safe-shutdown capability if a fire does occur (timely achievement of Hot Shutdown, and achievement of Cold Shutdown within 72 hours in Appendix R III.G.3 areas).
4. Prevent release of a significant amount of radioactive material if a fire does occur.

The Surry fire protection features are generally designed in accordance with the National Fire Protection Association code of record to furnish water and other extinguishing agents throughout the plant. Engineering evaluations of NFPA code compliance and other fire protection related items are provided in the 10 CFR 50 Appendix R Report. The types of fire protection features have historically been based on the recommendations of the Nuclear Energy Property Insurance Association, and provide the following:

1. Supply of water for fire fighting.
2. System for delivery of water to potential fire locations.
3. Automatic fire or smoke detection in the more critical areas.
4. Fire extinguishment by fixed equipment activated automatically or manually.
5. Manually operated portable fire-extinguishing equipment at strategic locations.
6. Fire barriers.

The following components are designed to Class I criteria (Section 15.2.1):

1. Engine-driven fire pump.
2. Diesel oil tank for engine-driven fire pump.
3. Yard hydrant piping.

Fire protection system design data are given in Table 9.10-1.

In addition to its primary function, the fire protection system also provides alternate sources of makeup water to certain other plant systems as follows:

1. Auxiliary Feedwater System. This interconnection can be used for the fire protection system to provide an emergency water supply to the suction of the Unit 1 and Unit 2 Auxiliary Feedwater Pumps.
2. Spent Fuel Pool. A normally covered outlet above the spent fuel pool is supplied from the fire protection system for emergency makeup water to the pool. Teeing into this FP makeup

line inside the Fuel Building is a line that is accessible external to the Fuel Building which can be used to enable supply by an external makeup source.

These secondary functions of the fire protection system do not prohibit the system from performing its primary function. In accordance with BTP-APCSB 9.5-1, Appendix A, Paragraph A.4, postulated fires need not be considered concurrently with other plant accidents.

As previously stated, part of the regulatory criterion is compliance with Appendix A to BTP APCSB 9.5-1. Section F to Appendix A, *Guidelines for Specific Plant Areas,* identifies the specific areas of the plant that require fire suppression systems. Section F.18, *Miscellaneous Areas,* states “Miscellaneous areas such as records storage areas, shops, warehouses, and auxiliary boiler rooms should be so located that a fire or effects of a fire, including smoke will not adversely affect any safety related systems or equipment.” Section F.18 does not require a fire suppression system but relies on building location to protect safety related systems and equipment. The following fire suppression systems are not required for compliance to regulatory criterion since the areas they protect meet Section F.18 and do not adversely affect safety-related structures, systems or components or affect safe shutdown capability in the event of a fire.

Administration Building Sprinkler System
Construction Clean Change Building Sprinkler System
Fabrication Shop Sprinkler System
Fuel Oil Storage Tank Foam System
Gravel Neck Combustion Turbine Facility Sprinkler System
Southeast extension of Simulator Building Sprinkler System
Paint Shop Sprinkler System
Records Vault Sprinkler System
Security Building Sub-Floor Halon System
South Annex Sprinkler System
Station and Chemical Warehouse Sprinkler System
Surry Nuclear Information Center (SNIC) Sprinkler System
Training Center Halon and Sprinkler System
Warehouses (1, 2, 7, and 8) Sprinkler Systems
Turbine Deck Security Office (TDSO) Sprinkler System
Beyond Design Basis (BDB) Storage Building Clean Agent System

9.10.2 Description

An arrangement drawing of the fire protection system is provided in Figure 9.10-1.

9.10.2.1 **Fire Detection and Signaling**

The fire detection and alarm systems are installed on a multiplexed system in accordance with the guidelines of National Fire Protection Association (NFPA) Standard 72D-1975. (See Section 9.10.1 for reference to code evaluations) An operator Information Management System (IMS) panel, installed in the Main Control Room, provides plant operators with the status of the system and its detectors. This operator IMS panel employs color graphics displays to indicate the current status of the system. Addressable smoke and heat detectors are utilized which allow the status of individual detectors to be available to plant operators and technicians. The detectors for each zone are connected to local multiplex panels; these multiplex panels are located throughout the plant and are connected via computer network back to the operator IMS panel. The multiplex network is a combination of Class A and B circuits as defined in NFPA 72D-1975. All detector zones on this system are supervised circuits.

Electronic programmable heat detectors combine the features of rate compensated/fixed temperature sensing and rate-of-rise temperature sensing. The rate-of-rise and rate compensated/fixed temperature features are independently configurable. Additionally, the fixed temperature setpoint is configurable. Configurable features are individually set for each detector through programming of the Fire Alarm Control Panel which monitors the detector.

Smoke detectors of the photoelectric type use a pulsed infrared LED light source and a silicon photoelectric receiver for smoke sensing. The sensitivity of the detector is user-selectable. The ability of this detector to sense smoke particles in the smoke chamber is not adversely affected by air flow. These detectors are also capable of detecting and compensating for environmental factors, such as dust and dirt.

The system provides fire detection coverage for the following areas:

1. Reactor Containment (Units 1 and 2)
    - Cable penetration area (includes thermal detectors)
    - Recirculation Air System ducts
2. Emergency Switchgear and Relay Rooms (Units 1 and 2)
    - Normal Switchgear Rooms (Units 1 and 2)
    - Cable Tray Room (Units 1 and 2)
3. Auxiliary Building
    - Charging pump cubicles general area
    - Charging pump cubicles exhaust ducts
    - Elev. 45'-10"
    - Elev. 27'-6"
    - Elev. 13'-0"
    - Elev. 2'-0" above the charging pump cooling water pumps
    - Solid Waste Drumming Room
    - S. E. and S. W. cubicle exhaust ducts
4. Containment Spray Pump House (Units 1 and 2)

- Upper Level
- Basement Level

5. Main Steam Valve House (Units 1 and 2)
6. Safeguards Building, Elev. 19’ 6” (Units 1 and 2)
7. Control Room Complex
8. Fuel Building, Elev. 6'-10"
9. Decontamination Building, vent system exhaust duct
10. Fire Pump Building
11. Mechanical Equipment Room 3
12. Battery Rooms 1A, 1B, 2A, 2B
13. Security CAS Building (includes thermal detectors)
14. Condensate Polishing Building - above MCCs
15. Boron Recovery Pump House
16. Technical Support Center
    - Main Area (includes one thermal detector)
    - HVAC Room
    - Battery Room
    - Electrical Room
17. Black Battery Building
18. Laundry Building (includes thermal detectors)
19. Cable Vault (Units 1 and 2)
    - Penetration Area
    - General Vault Area
    - MCC Room
20. Service Building Cable Tunnel (Units 1 and 2)
    - North South Cable Tunnel
    - East West Cable Tunnel
    - Service Building Cable Vault
21. Mechanical Equipment Room No. 5
22. AAC Building (includes smoke and thermal detectors)
23. Low Level Intake Structure (LLIS) Buildings

24. Mechanical Equipment Room 4 (Charging Pump Service Water Pump Room)

Two heat detectors have been installed in the charcoal filter of each unit in the gaseous waste disposal room of the auxiliary building.

The fire detection system is powered from normal station service distribution panels. On loss of power, an emergency 24V battery power unit supplies power to the detectors. The emergency power unit consists of a 24V battery, battery charger, a static inverter and an automatic switching control capability. Normal power is restored automatically following recovery from a loss of offsite power.

Upon actuation of an individual detector for a Fire Alarm Control Panel, an alarm signal is transmitted to the operator IMS panel in the control room, where the signal is visually annunciated by area and an audible alarm is initiated.

Activation of sprinkler and deluge extinguishing systems also annunciates an alarm (by area) on the operator interface panel in the control room. The CO_2 extinguishing systems also annunciate an alarm (by area) on the operator IMS panel. The Fire Alarm Control Panel and CO_2 extinguishing system at the Low Level Intake Structure alarm on the Operator IMS panel.

The fire detection and alarm system is electrically supervised. Trouble indication is initiated at the fire alarm control panels as well as the operator IMS panel in the event of loss of power, undervoltage, shorted/open circuits, or ground faults.

9.10.2.2 **Fire Control Systems**

9.10.2.2.1 Water Storage Tanks

Water for fire fighting is obtained from two 300,000-gallon water storage tanks each with 250,000 gallons reserved exclusively for the fire protection system, and 50,000 gallons in the upper portion of the tanks available for domestic water use. Each tank has a separate line to the suction header of the fire pumps located in the adjacent fire-pump house. The lines from the tanks to the suction header are equipped with isolation valves that can be closed to prevent both tanks from draining in the event of a leak. The tanks are supplied from two wells.

Backup water for fire protection can be obtained in an emergency from the two 300,000 gallon condensate storage tanks or by taking suction from the intake canal and discharging into the fire loop through a hydrant.

9.10.2.2.2 Fire Pumps

Individual 16-inch suction lines, adequately separated, are provided from each of the two water storage tanks to the fire-pump house, which is situated adjacent to the tanks. Two horizontal shaft, centrifugal fire pumps are installed in the pump house, each with a design capacity of 2500 gpm at a total dynamic head of 231 feet (minimum). One of the fire pumps is diesel-engine-driven and is supplied from a 460-gallon fuel tank that is capable of supplying the unit for over 8 hours of running time. The second fire pump is electric-motor-driven, with power supplied from the normal plant electrical system.

The firewater system is normally pressurized by a 30-gpm pressure maintenance pump and hydropneumatic tank that is automatically cycled to maintain 100 to 110 psig. The motor-driven and diesel-driven pump operate automatically and sequentially. The motor-driven pump will start automatically when the fire main pressure drops below 89 psig. A further drop of pressure in the fire water system will automatically start the diesel-driven fire pump. The diesel-driven fire pump will also start automatically upon a loss of ac control power. Both fire pumps may be manually started from the control room. The status of the fire pumps is indicated in the control room and at the fire pump control panels in the pump house. There are no safety-related cables or equipment in the fire-pump house.

The fire pumps and their ancillary equipment are adequate to deliver the required quantities and pressures of water to the fire protection systems.

The adequacy of the arrangement of the equipment within the fire-pump house is addressed in Section 9.10.4.24.

9.10.2.2.3 Firewater Piping System

The underground yard main system encircling the plant is supplied by two 12-inch lines from the fire-pump house, and is provided with isolation valves at the juncture, enabling either or both fire pumps to discharge into either line supplying the yard main loop.

All yard fire hydrants, automatic suppression systems, and interior fire-hose lines are supplied from the fire main yard loop. Post indicator sectional valves are provided on the loop to permit isolation of sections of the loop without interrupting service to the entire loop.

Fire hydrants with hose houses are provided approximately 250 feet apart around the exterior of the plant. Each hose house contains an inventory of fire-fighting equipment (hose, nozzles, adapters, wrenches, portable lights, etc.), and the doors generally are secured by breakable locks. Hose houses are set on concrete pads to prevent water accumulation and are clear of obstructions to opening properly. The area around the houses is maintained clear of objects that could block access or inhibit the extension of hose during fire-fighting evolutions.

Frostproof hydrants with 6-inch barrels with at least two 2.5-inch hose outlets are connected to the yard loop with 6-inch lead-ins from the yard main loop. A block valve is provided in the line to the hydrant that branches from the auxiliary building fire main feeder. This will allow servicing this hydrant without closing down part of the yard loop. This is the only hydrant for which closing down a portion of the yard loop would interrupt suppression capability to safety-related areas or areas posing a potential hazard to safety-related areas.

Threads on each of the hydrant outlets are compatible with the local fire department hose threads, and the guard posts provide acceptable protection to the hydrants against vehicular traffic.

9.10.2.2.4 Interior Fire Hose Stations

Manual hose stations are located throughout the plant.

Most areas of the plant containing safety-related equipment can be reached by hose stations. Hose stations in the turbine building have sufficient hose to cover all areas of the switchgear rooms and are equipped with nozzles suitable for extinguishing electrical fires. All locations on the 29 ft. 6 in. elevation of the turbine building can be reached by a maximum of 100 feet of 1.5-inch hose from an interior hose station.

The auxiliary building is protected by interior hose stations. To increase reliability, the auxiliary building fire hose system was modified so that the fire hose stations could be supplied from either Unit 1 or Unit 2 turbine building fire suppression headers, in addition to its normal supply from the yard fire main loop. The turbine building hose station at the entrance to the cable tray rooms has sufficient hose to reach all areas of both cable tray rooms and both mechanical equipment rooms. The hose rack outside the cable tray rooms is equipped with a fog-type nozzle suitable for electrical fires. The auxiliary building hose system can also supply, at a reduced flow, the auxiliary building general area exhaust filters should the normal supply from the Unit 1 and 2 turbine building fire protection loop fail.

The reactor containment of each unit is protected with normally dry interior hose stations. The fire hose standpipe system may be filled by opening manual valves in the auxiliary building piping penetration areas.

9.10.2.2.5 Water Suppression Systems

Automatic sprinkler systems are installed at the following areas:

1. Turbine Building, Ground Floor and Mezzanine Levels
2. Turbine Oil Storage Room
3. Auxiliary Boiler Room
4. Portions of the Service Building (Renovated Personnel Areas, Maintenance Services Offices, etc.)
5. Condensate Polishing Building
6. Machine Shop Building
7. Laundry Building
8. Station Warehouse
9. Construction Clean Change Building

10. New Training Center Building
11. Southeast extension of Simulator Building
12. On-line Chemistry Monitoring Computer Room (Pre-action system with smoke detectors)
13. AAC Building (includes smoke and heat detectors)
14. Turbine Deck Security Office (TDSO)

A manually activated sprinkler system is installed in each unit's Service Building Cable Vault and Tunnel. This system has open heads for protection of cable trays in the high ceiling upper level of the Vault, and closed heads for floor coverage in the lower area of the Vault. Manually initiated deluge systems are provided at the lube-oil reservoir coolers, hydrogen seal oil units, and the turbine lube-oil conditioners. Automatic heat-actuated deluge systems are provided at the main and service transformers and at the auxiliary building charcoal filter 1-VS-FL-14. Heat collector plates are installed per NFPA requirements over sprinkler heads under grating walkways in the turbine building.

The design and installation of these systems conform to the provisions of the National Fire Protection Association Standards 13 and 15. (See Section 9.10.1 for reference to code evaluations) In general, sprinkler and deluge systems have been provided at major concentrations of hazardous combustibles.

Electrical supervision of all automatic fire suppression systems is provided. In the event that any isolation valve in a sprinkler or deluge system is less than fully open, a control room annunciator and a local indicator are actuated. No electrical supervision is provided for normally closed valves in the fire water system.

9.10.2.2.6 Foam Extinguishing Systems

The aboveground steel fuel-oil tank in the yard is provided with a foam fire suppression system capable of applying foam to the surface of the liquid within the tank. Equipment consists of a foam-making eductor, piping to the tank, and supplies of AFFF-type foam concentrate. Adequate supplies of foam are kept on hand.

9.10.2.2.7 Carbon Dioxide Gas Suppression Systems

Low-pressure fixed carbon dioxide suppression systems utilizing a central storage tank capable of two applications are provided at the following areas:

1. Switchgear room, Unit 1.
2. Switchgear room, Unit 2.
3. Service building cable vault, Unit 1.
4. Service building cable vault, Unit 2.
5. Containment cable vault, Unit 1.

6. Containment cable vault, Unit 2.
7. Cable tray rooms, Unit 1.
8. Cable tray rooms, Unit 2.
9. Charcoal filter assembly A.
10. Charcoal filter assembly B.
11. High-pressure turbine bearing enclosure, Unit 1.
12. High-pressure turbine bearing enclosure, Unit 2.
13. Low-pressure turbine bearing enclosure, Unit 1.
14. Low-pressure turbine bearing enclosure, Unit 2.
15. Generator bearing enclosure, Unit 1.
16. Generator bearing enclosure, Unit 2.
17. Emergency generator room 1.
18. Emergency generator room 2.
19. Emergency generator room 3.
20. Motor control center room, Unit 1.
21. Motor control center room, Unit 2.

There are also three separate high-pressure carbon dioxide extinguishing systems utilizing agents stored in cylinders located adjacent to the point of application. These systems protect the fuel-oil pump houses A and B, the emergency service water pump house at the low-level intake structure, and the Technical Support Center (TSC) charcoal filter. The system that protects the charcoal filter in the TSC area is not required for safe shutdown.

The low pressure and high pressure CO_2 systems are provided with heat detectors and with remote manual pull stations. CO_2 systems for Charcoal Filter Assemblies 1-VS-FL-3A and B for Emergency Generator Rooms 1, 2, and 3 are manual systems only, so heat detectors for these two areas provide an alarm only. The CO_2 systems in other areas are actuated by heat detectors. Hand valves on the discharge heads of the high-pressure cylinders or manual activation switch provide manual release of the carbon dioxide gas.

For the high pressure systems, emergency electric power is provided by rechargeable batteries. The battery charger transfer module maintains the batteries at full charge and provides the means of automatically supplying 24V dc emergency power to the system during main power outages.

Areas protected by automatic discharge systems are equipped with predischarge alarms to alert personnel that carbon dioxide flooding is imminent. Carbon dioxide lockout control for personnel protection is installed for the switchgear rooms, cable tray rooms, and service and containment cable tunnels, intake structure and fuel oil pumphouse. Actuation of a system lockout switch will initiate an alarm on the main control board and at the carbon dioxide system control panel.

All ventilation system fans in the Low Pressure CO_2 Fire Protection System protected areas are stopped and the area open doors are closed upon initiation of the CO_2 discharge. All ventilation and fire dampers that are required for CO_2 retention are closed upon initiation of the CO_2 discharge in the affected area.

9.10.2.2.8 Portable Fire Extinguishers

Fire extinguishers are installed and are maintained in accordance with NFPA 10 and 10A. (See Section 9.10.1 for reference to code evaluations)

9.10.2.2.9 Halon 1301 Systems

Total flooding, Halon 1301 (bromotrifluoromethane) systems are provided for the following areas:

1. Emergency Switchgear and Relay Room, Unit 1 (manual)
2. Emergency Switchgear and Relay Room, Unit 2 (manual)
3. Training Center Building
   a. Computer Room of the Simulator Control Room
   b. Simulator Area
   c. Computer Room in Southeast extension of Simulator Building
4. Under-floor area of the main Security Building

The Emergency Switchgear and Relay Rooms contain equipment required for safe shutdown. The Halon systems for these rooms are described in detail below.

The Halon 1301 System for the Unit 1 and 2 emergency switchgear rooms is a total flooding system (will fill entire enclosure for Unit 1 or Unit 2). Each unit's Emergency Switchgear Room is considered a separate hazard area. The systems are manually operated.

The main bank of Halon storage bottles for each Unit's Emergency Switchgear Room Halon system is located outside the hazard area. The reserve cylinders may be manually connected once the main bank is exhausted if required. The system has been designed in accordance with the requirements of NFPA 12A. (See Section 9.10.1 for reference to code evaluations)

The initial discharge will be completed within seconds and will attain the design concentration level in the protected space. A subsequent discharge will occur to make up for the reduction in Halon concentration due to leakage or dilution by ventilation. The concentration of Halon in air will be maintained for a minimum of 10 minutes. Factors such as uncloseable openings, time required for dampers to close, and general tightness of enclosure have been taken into consideration.

Nozzles have been placed to provide a uniform level of concentration throughout the rooms.

The manual discharge switches are provided outside each protected area. The Unit 2 switch is located near the main entrance to the Unit 2 Emergency Switchgear Room, and the Unit 1 switch is located in Unit 2 Emergency Switchgear Room near the entrance to Unit 1. One push button for each system is also provided in the Control Room Halon Control Panel. Operation of the manual discharge switches causes immediate activation of horns, warning lights, shutdown devices (such as fire dampers) and the pre-discharge timer, which delays system activation for 60 seconds to allow for the exiting of personnel from the ESR before discharging Halon into the room.

In the event of loss of normal power, the control panel will provide battery backup to operate the panel under normal load for 24 hours and then be capable of operating the system for five minutes continuously during an alarm condition.

Both the supply air and exhaust air ducts leading from the Emergency Switchgear Rooms are isolated from the rest of the plant by automatic closing of the fire dampers located in these ducts where they penetrate the ESR enclosure. The recirculating HVAC system will remain in operation to help provide for continual mixing of Halon within the enclosure. Air movement patterns, ceiling configuration and equipment configuration have all been taken into consideration in locating the discharge nozzles.

The Halon 1301 Fire Suppression System is not required to operate during or after a seismic event but portions of the system are seismically supported to prevent possible damage to surrounding safety-related equipment.

The existing structures which interface with the Halon System have been reviewed to ensure that the addition of the Halon System does not have any adverse impact on the seismic qualification of the existing structures, systems, or other components important to safety.

The Emergency Switchgear Rooms (ESRs) are required to meet the requirements of Section III.G.3 of Appendix R. Section III.G.3 requires fire detection and a fixed fire suppression system be installed in the area under consideration. Manually actuated Halon fire suppression systems were installed in the ESRs as part of the modification made to comply with Appendix R. The system design was based on NFPA 12A (Reference 1), and in accordance with paragraph 1-8.1.1, the system can be manually actuated if acceptable to the authority having jurisdiction.

Based on discussion in Generic Letter (GL) 83-33 (Reference 2), the Halon system installed in the ESRs meets the requirements of a fixed fire protection system as required by III.G.3, in contrast to Section III.G.2 which requires an automatic fire suppression system. The installation of a manual Halon system is in accordance with NFPA 12A, 1980 edition. The Halon system meets the definition of a fixed fire suppression system as described by GL 83-33 and the Halon system is expected to extinguish a fire in the ESRs as concluded in NUREG/CR-3656 (Reference 3). In addition, the NRC's Inspection Report (IR) (Reference 4) addressed implementation of 10 CFR 50 Appendix R Sections III.G, III.J, III.L, and III.O at Surry. The IR acknowledged the fixed manual Halon system in the ESRs and concluded the fire area barriers and the fixed detection and suppression systems provided for these areas appear adequate. The ESRs are located beneath the control room thereby providing for prompt response from operations in the event of an alarm allowing the Halon system to be activated with minimal delay.

The Individual Plant Examination for External Events (IPEEE) submittal addressing fire (Reference 5) established an acceptable CDF without taking any credit for detection and suppression of fires in the ESRs. Since the ESRs comply with Section III.G.3, the units can be safely shutdown even in the event of a complete loss of the area. From an IPEEE perspective, the existence of detection and a fixed suppression system in the ESRs provides additional protection, which if modeled in the IPEEE, would result in an even more acceptable CDF.

9.10.2.3 **Ventilation Systems**

9.10.2.3.1 Smoke Removal

No special smoke-exhausting systems are provided at the plant. The normal ventilation systems can be used for smoke removal for some types of fires, even though they are not specifically designed for this purpose.

When normal ventilation systems cannot be used, the fire brigade will use portable ventilation units with flexible ducting for smoke removal.

9.10.2.3.2 Filters

Charcoal filters are used in the auxiliary building ventilation system filters, the Technical Support Center (TSC) ventilation system, the containment iodine charcoal filter units, the gaseous waste disposal system, and the control room emergency ventilation system. The auxiliary building ventilation system contains redundant safety related trains of charcoal filters housed in separate metal cabinets enclosed in separate concrete cubicles. The inlet and outlet dampers on these filter units can be shut to prevent radiation release from a damaged unit and the redundant unit can continue to operate. These units are currently protected by a manually actuated carbon dioxide suppression system. The auxiliary building ventilation system also contains a third, nonsafety-related charcoal filter housed in a separate enclosure. The third charcoal filter unit is protected by an automatic water spray system. The TSC charcoal filter unit is located in the service building in a concrete vault. It is protected by a heat detector system and a carbon dioxide system which may be either automatically or manually operated. The containment iodine charcoal filter units are enclosed in separate structures with 18-inch-thick concrete walls and roof. A fire in the containment iodine or TSC charcoal filter units would have no direct effect on safety-related equipment or cables because of the intervening distance and barriers. The gaseous waste disposal system charcoal filters are housed in a metal enclosure away from safety-related equipment and cables. These filters have heat detectors and can be isolated and air-cooled if subjected to excessive decay heating. The control room emergency ventilation system charcoal filters are located in the turbine building in a metal enclosure. These filters are isolable from the control room by a normally shut motor-operated damper in the supply pipe to the control room. The only safety-related cable located near the control room emergency ventilation charcoal filter is the power feed to the respective fan motor; therefore, a fire would not affect safe shutdown of the plant.

9.10.2.3.3 Breathing Equipment

There are at least 25 self-contained air-breathing apparatuses (SCBAs) dedicated at all times to fire brigade use. There are in excess of 50 spare air cylinders, rated at 30-minute capacity, available in the plant. Self-contained units are distributed at various locations throughout the plant, with five sets kept at the control room. The use of SCBAs for fire fighting is discussed in Section 11.1.

Air recharging for the fire brigade cylinders is from a twenty-cylinder cascade system that is recharged by an air compressor designed for that purpose. Recharging is carried out in the loss prevention storage room in the service building.

9.10.2.4 **Floor Drains**

In general, measures have been taken to prevent the spread of combustible liquids in the event of leakage from reservoirs and piping. The lube-oil reservoir, lube-oil cooler, and high-pressure control fluid reservoir for each unit are located in a diked area. The only floor drain is isolated by a locked-closed valve. The hydrogen seal oil unit is surrounded by a spillage trench to prevent the spread of lube oil. The two lube-oil storage tanks are located together in a diked area without drains. The fuel tank for the diesel-driven emergency service water pumps is located in a separate diked room, without floor drains. The lube oil conditioning unit and transfer pump for each unit are located in a diked area without floor drains. The wall tank portions of the emergency diesel generator day tanks are each located in a diked area without floor drains. Drains in the diesel generator rooms outside the dikes are plugged and dikes are provided at the doorway to each room. The diesel driven fire pump is located in a diked room and the floor drain is plugged.

Dikes have been provided at all doorways into the emergency switchgear rooms to prevent equipment damage due to water or combustible liquid flooding from adjacent areas. (See Section 9C.1.1.) A 3-inch dike has been provided between Units 1 and 2 emergency switchgear rooms to prevent possible fire protection water in one unit from flooding the adjacent unit. A deflector shield has been placed by the overhead fire main near the entrance to the emergency switchgear room in the turbine building to cause possible leakage flow to be diverted outside the dike (Section 9C.1.2).

Two foot high dikes are erected at the entrances to the charging pump cubicles to prevent pump damage from a transient combustible liquid spill or from possible fire protection leakage (Section 9C.1.2). These measures are adequate to contain leakage to the area of origin.

9.10.2.5 **Lighting Systems**

In addition to the normal plant lighting system, fixed emergency lighting is provided in the control room and at points of access and egress in the containment, auxiliary building, turbine building, and service building.

A fire could damage both normal and emergency lighting for any area of the plant. To deal with such a situation, emergency lanterns are provided. In addition, several portable emergency lanterns are provided for the exclusive use of the fire brigade.

A post-fire emergency lighting system has been provided for illumination of all areas needed for operation and/or monitoring of safe shutdown equipment, and to assure access/egress routes thereto, after a postulated fire in any area in accordance with the requirements of 10 CFR 50 Appendix R, Section III.J. The capacity of the installed emergency lighting is 8 hours. See Section 8.4.5 for further discussion of lighting systems.

9.10.2.6 **Communications System**

Reliance is placed primarily on the in-plant telephone system and a loudspeaker page and answer system for normal communications. In addition, a voice-powered telephone system is provided that uses voice-powered headsets and phone jacks installed throughout the plant. Due to loud background noise and the potential for fire damage such fixed systems are not always effective for fire-fighting operations. To overcome these problems, several fixed handsets or portable two-way radios are provided in the control room, the security building, and the Appendix R locker. One or more brigade members would take a two-way radio on the way to the fire scene.

To meet the requirements of 10 CFR 50 Appendix R, an emergency radio communication system is installed. The system provides total plant wide coverage.

There are two redundant radio transmission sites which simultaneously broadcast: the Primary Site in the station switchyard and the Secondary Site in the Unit 2 cable spreading room. Each radio site includes repeaters, antenna and network communication equipment and is capable of trunked radio operation.

Redundant antenna trains with amplifiers are installed throughout the Auxiliary Building and inside both containment structures to improve radio coverage. The Unit 1 communications system amplifier is located in the Auxiliary Building, and the Unit 2 amplifier is located in the Unit 2 Cable Tray Room.

The location of system equipment is such that a postulated fire in any one area would only destroy one system.

The communication system also consists of fixed handsets, and mobile and portable handheld units.

Also, additional portable mobile satellite phone equipment is available for offsite communication during a beyond design basis (BDB) event.

Dedicated system pagers are used to call out emergency personnel. Radio desksets used in the control room have telephone interconnects that allow notification of the pagers. A backup paging telephone utilizing a different telephone line is located at the Unit 1 Auxiliary Shutdown Panel.

9.10.2.7 **Electrical Cable**

The cable insulation used for power and control circuits consists primarily of cross-linked polyethylene with neoprene or hypolon jacket. Power circuits for some large components use interlocked armored cable. The flame test standard for cables, Institute of Electrical and Electronics Engineers Standard 383-1974, was not in effect at the time these cables were purchased and installed. However, 5000V and 6000V power cables were tested in accordance with IPCEA Standard 5-19-81, and 1000V control cables and 600V instrument cables were tested in accordance with ASTM D2633. In addition, control and instrumentation cables were required to pass a special flame resistance test detailed by Vepco in the purchase specifications. Based on the results of these tests, flame retardant coatings are not necessarily used on cables installed in the plant. Specifications for cables added in cable trays in recent years since the approval of IEEE 383 have required that the cable meet IEEE 383-1974, unless an evaluation is performed, documented and approved by Engineering.

9.10.2.8 **Fire-Barrier Penetration**

Fire barriers such as walls, floors, and ceilings are penetrated by ventilation ducts, electrical raceways, mechanical piping systems, and doors.

Electrical cable penetrations in fire barriers surrounding safety-related areas throughout the plant are sealed using materials and methods that have been tested by Vepco to verify their effectiveness as a fire barrier. The fire test for penetration seals, as described by Vepco in a fire hazards analysis, utilized a gas burner as a flame source. The test on each specimen was conducted for 3 hours or until flame or hot gases, hot enough to ignite cables, penetrated the top of the sealing material. The test verified that penetration seals meet NRC Branch Technical Position APCSB 9.5-1.

New penetration seals are made using silicone foam or other Engineering approved fire stop material with a 3-hour fire rating. The fire stop material may be used in conjunction with an approved permanent damming material, or in conjunction with temporary damming materials which are removed.

All doors which penetrate fire barriers required for 10 CFR 50 Appendix R are fire-rated. (See Section 9.10.1 for reference to engineering evaluations) These fire doors are labeled by

Underwriter's Laboratories or are addressed in the 10 CFR 50 Appendix R Report, Chapter 7, Exemption Requests, Engineering Evaluations, and Fire Retardant Cable Characteristics.

Most doors to areas containing significant amounts of combustible material are controlled by a magnetic key card locking device to ensure that they remain closed. Leaving one of these doors open results in an alarm in the security building control room. All members of the fire brigade are provided with magnetic key cards. In addition, keys readily available to security members of the fire brigade can be used to open doors if the magnetic latching mechanism is inoperative and the door failed in the locked position.

As in the case of electrical penetrations, ventilation duct and pipe penetrations have been sealed using methods that are considered adequate for most areas of the plant.

9.10.2.9 **Separation Criteria**

In most cases, redundant safety-related system components (e.g, pumps, diesel generators) are separated by distance or barriers. Cables of redundant safety-related divisions installed in the same area are separated using:

1. Rigid metal conduit (following separate routes where practical).
2. Trays one above the other without barriers when the trays are more than 4 feet apart.
3. Trays one above the other with barriers or tray covers when the trays are 4 feet or less apart.
4. Trays side by side with barriers.

Solid metal tray covers or equivalent have been provided on all cable trays where the separation of redundant safety-related cables does not meet the guidelines of Regulatory Guide 1.75 in the following areas: emergency switchgear rooms, cable vault and tunnels, cable tray spreading rooms, and auxiliary building. Also, solid metal tray covers or equivalent have been provided on cable trays in the reactor containment building cable penetration area. A barrier consisting of a fire resistive material has been provided between cable trays in the safeguards area where the separation does not meet the guidelines of Regulatory Guide 1.75.

Equipment and cable that is required for safe shutdown following a fire is identified in the 10 CFR 50 Appendix R Report, Chapter 3, *Safe Shutdown Systems Analysis,* and Table 9-2 of Chapter 9, *Electrical Associated Circuits & Separation Analyses,* respectively. Physical and electrical separation is provided between redundant or alternate shutdown components as described in 10 CFR 50 Appendix R Report, Chapter 4, Chapter 7, and Chapter 9.

9.10.2.10 **Fire Barriers**

Most of the Appendix R fire barriers in the plant are concrete or block with 3-hour fire resistance, or have evaluations that demonstrate equivalence to a 3-hour rating.

9.10.2.11 **Access and Egress**

All safety-related areas except the safeguards areas, service building cable vaults, fuel-oil pump houses, reactor containment buildings, and intake structure are reasonably accessible for manual fire fighting. Components within the safeguards area are adequately separated such that an increased response time from the fire brigade will not delay safe shutdown of the plant. A manual sprinkler system has been added in the service building cable vault such that the need for manual fire fighting is minimized. The fuel-oil pump houses are adequately protected by fixed suppression systems. During normal operation the containment is sealed, and special procedures are followed to gain access through a personnel air-lock. Since the intake structure is located 1.25 miles from the plant buildings, fire-fighting personnel and equipment must be transported to the intake structure. See Section 8.4.5 for discussion of features of the post-fire emergency lighting system which assures access and egress in accordance with the requirements of 10 CFR 50 Appendix R.

9.10.2.12 **Toxic and Corrosive Combustion Products**

The products of combustion of many polymers are toxic to humans and corrosive to metals. Prompt fire detection and extinguishment are relied on to minimize the quantity of such products. Additionally, means for smoke removal are provided as discussed in Section 9.10.2.3.1. The fire brigade is also provided with and trained in the use of emergency breathing apparatus for manually fighting fires involving such materials.

9.10.3 Evaluation of Plant Features

There are several combinations of safe-shutdown systems available in either unit that are capable of shutting down the reactor and cooling the core of either unit during and subsequent to a fire. The combinations available in a fire shutdown will depend upon the location of the fire and the effects of the fire on such systems, their power supplies, and their control stations. To ensure the safe shutdown of the reactor plants, those systems and components which insert negative reactivity into the reactor core, control cooldown of the primary reactor coolant system, and maintain reactor coolant inventory should be protected in the event of a fire, and measures should be taken to ensure their availability.

The general functional requirement for safe shutdown, and the system auxiliaries, major components, and instrumentation required to fulfill these requirements are described below.

9.10.3.1 **Reactivity Control**

The rod control system is of a fail-safe design. Faulting in the system circuits trips the reactor. Following the reactor trip, soluble poisons are added to the primary coolant system to ensure subcriticality. This is accomplished by using a charging pump to inject borated water from the boric acid system, if available, or from the refueling water storage tank into the reactor coolant system. There are three charging pumps per unit, one of which is required for reactivity control. In addition, a charging system cross-connect is installed to allow the use of the opposite unit's charging pumps for cooldown following an accident (Section 9.1.3.1).

In providing reactivity control, the boric acid solution is transferred from the boric acid tanks by the boric acid transfer pumps to the suction of the charging pumps. Alternatively, borated water can be supplied directly to the suction of the charging pump from the refueling water storage tank of either unit. Normally, operation of the charging pump requires operation of the charging pump cooling water and service water systems. The charging pump cooling water system provides a source of cooling for the charging pump mechanical seals. This system is cooled in turn through a heat exchanger by the charging pump service water system. The charging pump service water system also provides cooling directly to the charging pump lube-oil cooler. In the event of a fire, the charging pump cooling water system is not required for safe shutdown (since the charging pump suction would be from the cold water in the RWST), but the charging pump service water system is required for hot and cold shutdown as explained in the 10 CFR 50 Appendix R Report, Chapter 10, Engineering Evaluations.

9.10.3.2 **Reactor Coolant System Inventory Control**

Following a reactor shutdown or trip, the reactor coolant system water inventory is maintained by operation of the charging pumps. Reactor primary-grade water is added with boric acid solution to provide makeup for normal primary system leakage and shrinkage. The primary-grade water is transferred from the primary-grade water tanks by the primary-grade water supply pumps to the blender, located on the discharge of the boric acid transfer pumps. The primary-grade water supply pumps are not safety-related, and in the event of a loss of offsite power that would disable these pumps, the refueling water storage tanks would be used as the source of makeup water. Primary coolant letdown may be isolated, and the charging pump can be operated to maintain pressurizer level, which would otherwise decrease due to coolant contraction during cooldown. Operation of the reactor coolant letdown systems is not required to maintain pressurizer level, however an alternate means of reactor coolant letdown can be used as noted in Section 9.10.3.3. During normal operation, the charging pumps will provide reactor coolant makeup through the normal charging path and through reactor coolant pump seal injection. As part of establishing stable RCS flowpaths during certain fire scenarios, the reactor coolant pump seal injection is isolated on the fire affected unit, and charging flow is established through the normal charging flowpath, the High Head SI to Cold Legs flowpath, or the Alternate High Head SI to Cold Legs flowpath.

During normal operation, seal injection flow from the chemical and volume control system is provided to cool the reactor coolant pump seals, and the component cooling water system provides flow to the thermal barrier heat exchanger to limit the heat transfer from the reactor coolant to the reactor coolant pump internals. In the event of loss-of-offsite power, the reactor coolant pump motor is de-energized and both of these cooling supplies are terminated; however, the diesel generators are automatically started and seal injection flow is automatically restored within seconds. Component cooling water to the thermal barrier heat exchanger, however, must be manually reinitiated. Either of these cooling supplies is adequate to provide seal cooling and prevent seal failure due to loss-of-seal cooling during a loss-of-off-site power for at least 2 hours.

Appendix R requires the plant with fire damage to reach hot shutdown immediately and cold shutdown within 72 hours in Appendix R III.G.3 areas. Documentation was provided by the seal vendor (Flowserve) that shows that no additional seal leakage (other than Controlled Bleed-Off flow) would occur over the 72 hour Appendix R scenario duration.

9.10.3.3 **Decay Heat Removal**

Following a normal plant shutdown, the condenser steam dump system bypasses steam to the condenser to provide cooldown. If the condenser steam dump is not available, power operated relief valves on the main steam lines will provide cooldown by relieving main steam to the atmosphere. These power operated relief valves are backed up by code safety valves on each steam generator. For decay heat removal following a reactor trip, it is necessary only to maintain control of one steam generator. For the continued use of the steam generator for decay heat removal, it is necessary to provide a source of water and means of delivering that water. The auxiliary feedwater pumps (two motor-driven pumps and one turbine-driven pump per unit) are provided to deliver the water. The power and control cables for these pumps are located in the same fire zone at a number of points (i.e., containment spray, auxiliary feedwater, and main steam valve area, and the emergency switchgear and relay rooms). A fire in one of these areas could disable all three auxiliary feedwater pumps of a given unit; however, in the event of such a fire, there exists the alternative of providing auxiliary feedwater from the opposite unit. Since these cross-connect valves are not located in an area that would be affected by a fire that could damage the auxiliary feedwater pumps or cables for one unit, the auxiliary feedwater pumps of the opposite unit would be available to supply water to the steam generator being used for decay heat removal. A fire in one of these areas could disable remote operation of all three power operated relief valves on the main steam lines of a given unit. However, in the event of such a fire, there exists the alternative of locally operating the power operated relief valves using a portable air source and quick-connect instrument fittings provided at the valves.

For cooldown of the reactor coolant to a temperature of less than 200°F, the residual heat removal system is used. The residual heat removal system consists of redundant heat exchangers, pumps, and associated piping, valves, and instruments. A QA Category II, Seismic Class 1 radiant energy shield is installed between the residual heat removal pump motors to protect one of the two motors in the event of a motor fire. This shield ensures that at least one residual heat removal pump is available for the safe shutdown of the unit. A post-fire repair will be used to restore power to the RHR pump motors in the event a fire disables both pump’s cables or power supplies.

Adequate subcooling can be maintained by cooling the reactor coolant system faster than the pressurizer is being cooled and depressurized by ambient heat without the use of pressurizer heaters. Loss of pressurizer heaters would only accelerate plant cooldown. The resultant cooldown rate would be within Technical Specification limits.

To insure compliance with 10 CFR 50 Appendix R for providing plant cooldown capability following a postulated fire, certain valves in the chemical and volume control system, the residual heat removal, and the component cooling water system are required to be functional in order to provide an alternate means of reactor coolant letdown, pressurizer pressure control, and decay heat removal. These valves, which are identified in Section 9.1.2.1, 9.3.2.1, and 9.4.3.1, are equipped with quick-disconnect instrument air fittings so that they may be operated locally with a portable air source.

9.10.3.4 Auxiliaries

Auxiliaries required for safe shutdown include the component cooling system, the service water system, the circulating water system, certain ventilation systems, and appropriate instrumentation and power supplies. Multiple outside sources of power are available to the plant for both normal operation and shutdown functions. Normal operations may utilize either offsite or unit-generated power. The power supplies to redundant safe shutdown equipment are electrically separated. Emergency diesel generators supply power for shutdown operations when offsite or unit-generated power is not available.

The fuses supplying 125V dc control power to the safety-related 4160V and 480V circuit breaker close and trip circuits are sized to provide electrical coordination between the fuses and the feeder and load breakers. The original fuses were replaced by smaller fuses to eliminate the possibility of causing the loss of the 4160V or 480V switch gear control circuitry. This modification assures availability of power sources to safe shutdown equipment in accordance with 10 CFR 50 Appendix R.

The component cooling water pumps may be cross connected to serve either unit. Component cooling water system operation is not required for hot shutdown.

The circulating water and service water systems are required for cold shutdown in order to supply cooling to certain safe shutdown components such as the component cooling water heat exchangers, and the air conditioning and chilled water condensers.

Ventilation is required for several areas of the plant during safe shutdown operations in order to protect electrical equipment from heat damage and allow access for operator actions (such as in the control room, emergency switchgear room, and auxiliary building).

9.10.3.5 Instrumentation and Control

An auxiliary shutdown panel located in each emergency switchgear room has control switches for the following functions:

1. Emergency boration valve.
2. Auxiliary feedwater pumps and associated discharge valves.
3. Charging pump.
4. Pressurizer heaters.

Complete electrical isolation from the Control Room is provided for those circuits on the auxiliary shutdown panels which are required for safe shutdown. Appendix R isolation panel

(AS-2) is located in MER-5. In the event the control room becomes uninhabitable, chillers 1-VS-E-4D and 4E control power can be locally controlled.

The Remote Monitoring Panels, located in the Unit 1 Cable Spreading Room, have vital process instrumentation for both Units 1 and 2. Cabling for this instrumentation is independent of the cabling for similar instrumentation in the Control Room. (See Section 7.7.2.)

Emergency Condensate Storage Tank Level can be monitored via indication on the tank. Refueling Water Storage Tank Level is not required to be monitored during safe shutdown following a fire (see NRC’s Safety Evaluation dated 2/25/88 regarding exemption requested).

9.10.3.6 **Effects of Fire Suppression Systems on Safety Systems**

The following effects have been reviewed: (1) breaks in fire protection piping that may result in water flooding damage to safety-related equipment; (2) cracks in fire protection piping that may result in water spray damage to safety-related equipment, or that may impair suppression capability of both primary and backup means of suppression; and (3) inadvertent fire protection system actuation that may result in damage to safety-related equipment.

In most areas, curbs, drains, and the mounting of equipment above the floor level minimizes the potential for flooding damage. In other areas, water will drain out doors or via stairways or through grating to lower elevations, so that the standing water would not affect safety-related equipment. In addition, valves have been provided to isolate sections of piping inside buildings to preclude the buildup of water and thus prevent equipment from being incapacitated due to flooding.

Water flows from automatic fire suppression systems are annunciated on the fire panel in the control room. Flow from manual hose stations is not annunciated but will cause the fire pump to start, thereby transmitting a “fire pump running” signal to the control room. A flow from the fire protection water system can thus be inferred.

There is some safety-related equipment in various areas of the plant that would be vulnerable to the effects of water spray. There are, however, no fixed water suppression systems in these areas.

9.10.4 Evaluation of Specific Plant Areas

9.10.4.1 **Control Room Complex**

The control room complex is an area approximately 52 feet by 104 feet located at grade level adjacent to the turbine building, between the turbine building and the auxiliary building. The complex consists of the control room, the control room annex, office area and toilet, the Unit 1 and Unit 2 control room air-conditioning equipment rooms, and the Unit 1 and Unit 2 computer rooms.

The only spaces within the control room complex that contain safety-related equipment are the separate Unit 1 and Unit 2 control room air-conditioning rooms, and the single control room that serves both units. Each air-conditioning room contains two 100%-capacity air-handling units for the control room complex. The control room is a continuously manned station that contains all of the instrumentation and control equipment necessary to operate the plant under both normal and abnormal conditions. This equipment includes the redundant control cables, indicating instruments, and control switches used to trip the reactor and to maintain it in a safe-shutdown condition.

An auxiliary shutdown panel located in each emergency switchgear room contains control switches to facilitate shutdown in the event of damage to control room equipment or a forced evacuation of the control room. A remote monitoring panel located in the Unit 1 Cable Tray Room contains process instrumentation to facilitate safe shutdown, and emergency diesel generators No. 1 and No. 2 are provided with local control panels which are electrically isolated from the Control Room. These and other features provide an alternative safe shutdown capability in the event of a fire in the Control Room in accordance with 10 CFR 50 Appendix R. The residual heat removal pumps and the component cooling water pumps are normally controlled from the control room. In the event of a control room evacuation the pumps for both systems can be operated at the switchgear in the emergency switchgear room. See Section 7.7.2 for discussion on compliance with 10 CFR 50 Appendix R. Other modifications made as a result of 10 CFR 50 Appendix R requirements provide the operator with the capability of manually closing the main steam line trip valves from either the control room or the emergency switchgear room. The steam generator power operated relief valves can be closed using key-operated switches located in the unit's cable vault or the valve positioner controller located in the MCR. These redundant controls allow valve closure in the event that one of the control methods has sustained damage due to a fire or the area where the control is located must be evacuated. See Section 10.3.1.2 for additional discussion of this modification which is in accordance with 10 CFR 50 Appendix R requirements.

The combustible material in the control area consists of a moderate amount of electrical cable insulation, parts of electrical components in panels and consoles, desktops on the SRO console and Plant Computer System consoles, parts of computer terminals, carpeting, anti-fatigue flooring, and a moderate amount of Class A combustibles such as log books, drawings, operating procedures, and computer printouts.

The control room complex is bounded on all sides by concrete, which provides a 3-hour-rated fire barrier. Ventilation ducts that penetrate the boundaries are provided with fire dampers. The south wall of the complex, adjacent to the turbine building, contains emergency ventilation ducts constructed of heavy-gauge pipe which may be sealed by motor-operated dampers controlled from the control room. Closure of these dampers will provide adequate protection for the control of smoke and hot gases. Individual spaces within the complex are separated by 8-inch concrete block walls and metal doors with no specified fire rating. The control room is penetrated by ventilation ducts from the control room annex, computer room No. 1, and the control room ventilation rooms, which are provided with manual smoke dampers. Access to the control room is via fire-rated doors. The fire rated doors are from the turbine building walkway to the control room, from the back stairway to the Unit 1 control room air conditioning room, from the back stairway to the rear control room corridor, from the control room annex to the turbine building, and from the control room annex to the tagging room.

Access to the control room annex is via two Class A fire rated doors which are; (1) from the turbine building walkway, and (2) from the operations personnel support room.

The doors; (1) from the turbine building walkway to the control room annex, (2) from the turbine building walkway to the control room, and (3) from the operations personnel support room to the control room annex are backed up by missile protection doors.

The door between the control room and the control room annex is a bullet-proof door locked closed with a card reader. Louver covers, which are mounted on the doors, can be manually slid down in place to prevent smoke from entering the control room through the door louvers.

Manual actions by plant personnel are relied upon to suppress a fire. The area is relatively uncongested, with adequate space for manual fire fighting. Portable dry-chemical and carbon dioxide extinguishers are located throughout the control room complex. A hose station is located in the turbine building just outside the entrance to the control room. Self-contained breathing units are located in the control room.

9.10.4.2 **Emergency Switchgear Rooms**

Separate areas located below the control room and the Technical Support Center are provided for each unit's emergency switchgear and control relays. Each area is composed of two emergency switchgear rooms, one for each division, and a single relay room. Each room has approximately 2500 ft^2 of floor space. The rooms within each area adjoin each other in an L-shaped configuration, with open passageways between them. There is also an open passageway with a 3-hour fire-rated sliding door between the Unit 1 and Unit 2 areas. The sliding fire door is normally open and will automatically close upon actuation of either the Unit 1 or Unit 2 Halon system or a smoke detector associated with the door.

The emergency switchgear and relay room contain safety-related switchgear and control relays, including redundant equipment required for safe shutdown, and the remote shutdown control panels for each unit. Large quantities of safety-related power and control cables are routed above the switchgear cubicles and relay boards throughout the area and in the open passageways between rooms. The emergency 125V dc batteries are also located in the area in separate rooms within their associated division switchgear rooms. Alternative safe shutdown capability in the event of a fire in this area is provided in accordance with 10 CFR 50 Appendix R. See Section 9.10.4.1 for discussion on the post-fire capability of manually closing the main steam line trip valves and/or the steam generator power operated relief valves. These features provide compliance to the requirements of 10 CFR 50 Appendix R.

The combustible materials in the area consist of a large amount of electrical cable insulation and parts of electrical components in the switchgear cubicles and relay boards. There is also a potential for a small amount of transient lubricating oil to be transported via the Unit 2 switchgear rooms to mechanical equipment room No. 3.

The emergency switchgear and relay room areas for each unit are bounded on all sides by concrete, which provides a 3-hour fire barrier. The individual rooms within each area are also separated by concrete or concrete block walls. As noted above, these walls are penetrated by open passageways. Where cable trays penetrate the walls separating individual rooms within each unit, intermediate fire stops are installed in the trays.

Manual actions by plant personnel are relied upon to suppress a fire. Access to the Unit 1 area is through the normally open fire-rated door from the Unit 2 area and through two fire-rated doors from the Unit 1 cable vault. The Unit 2 area is accessed through (1) a fire-rated set of double doors from the turbine building; (2) a 3-hour fire-rated door to a stairwell from the control room above; and (3) a fire-rated door from the Unit 2 cable vault.

Both the Unit 1 and Unit 2 area floor space is sufficiently clear to permit access by fire fighters, and smoke can be exhausted through the turbine building roof fans or into the cable vault and tunnel area to the motor control center rooms and outside.

Portable carbon dioxide extinguishers are located in both areas, and a 150-lb wheeled, carbon dioxide extinguisher is located in the Unit 2 area. Also, a 1.5-inch hose station is located in the turbine building just outside the entrance to the Unit 2 area.

The emergency switchgear and relay room area for each unit is protected by its own Halon fire suppression system. Each system is capable of flooding an emergency switchgear and relay room area with an adequate concentration of Halon for 10 minutes. The bottles supplying this system are located outside the emergency switchgear rooms in the turbine building.

9.10.4.3 **Containment Penetration Vaults, Cable Tunnels, and Service Building Cable Vaults**

Each unit’s containment penetration vaults (outside containment), cable tunnels, and service building cable vaults are adjoining spaces used as cable spreading and routing areas. The penetration vaults and service building cable vaults are connected by the cable tunnels. These three spaces constitute a single fire area. Separate areas are provided for each unit on either side of the auxiliary building between the service building and the unit containment building. Alternative safe shutdown capability in the event of a fire in this area is provided in accordance with 10 CFR 50 Appendix R. Modifications made as a result of 10 CFR 50 Appendix R requirements provide the operator with the capability of manually closing the steam generator power operated relief valves from either the control room or the units’ cable vault and tunnel area. See Section 10.3.1.2 for additional discussion of this modification.

All of the spaces within these cable spreading and routing areas contain a large number of safety-related cables, including control and power cables for equipment required for safe shutdown. The outside containment penetration vaults also contain the redundant hydrogen recombiner power supplies and emergency motor control centers.

The only combustible material in significant quantity is the insulation for the large number of electrical cables in the areas.

The separate cable spreading and routing area provided for each unit is bounded on all sides by concrete or concrete blocks, which provide a fire barrier surrounding the three adjoining spaces within a unit. Each area is provided with a total flooding automatic carbon dioxide suppression system and a separate fire detection system that alarms in the control room. The automatic carbon dioxide system is backed up by manual suppression capability using manually actuated water sprinkler system in the Service Building Cable Vault, portable extinguishers located in the area, and water hoses from cable vault standpipe, yard hydrants and the hose stations in the turbine building. The areas can be accessed at one end from the outside yard via the motor control center rooms and a spiral staircase down to the outside containment penetration vaults, and at the other end from the turbine building via one of the emergency switchgear rooms. Smoke and heat can be exhausted up the spiral staircases and through the doors of the motor control center rooms to the outside. Adequate floor space is available to permit access by fire fighters to all locations within the areas.

9.10.4.4 **Battery Rooms**

There are four 125V dc station battery rooms. A separate battery is provided for each division of each unit’s safety-related equipment. Each battery is housed in a separate battery room approximately 9 feet by 14 feet, located within or adjacent to the associated division’s emergency switchgear room.

The combustible material in the rooms consists of the plastic battery cases and the battery power cable insulation.

An unmitigated fire in a battery room could disable one of the station batteries. Such a fire would not prevent safe shutdown, however, since redundant equipment controlled from the other train’s battery would still be available, and since the dc load on the other train’s battery would still be fed from the battery chargers.

Each battery room is bounded on all sides by concrete or concrete block, which provides an adequate fire barrier. Ventilation ducts that penetrate the barrier are provided with fire dampers and the doors to the rooms are 3-hour fire-rated. Manual actions by plant personnel are relied upon to suppress a fire. The battery rooms themselves and the areas used for access to the battery rooms are relatively uncongested, with adequate space for manual fire fighting. Portable Class C extinguishers are located nearby in the emergency switchgear rooms, and a wheeled Class C extinguisher is located in the Unit 2 division J emergency switchgear room. Also, 1.5-inch hose stations are located in the turbine building within reach of all the battery rooms.

During normal system operation the fire potential in a battery enclosure is virtually negligible because battery hydrogen generation is negligible. Even though battery hydrogen generation is negligible, air flow detectors have been installed in the battery room ventilation exhaust ducts with annunciation in the control room if there is no air flow. If the smallest battery room was sealed at equalize charge at an elevated temperature of 87°F, the lead calcium batteries would require greater than 40 hours to attain the burnable threshold concentration of four percent hydrogen. In the event of the worst case two-hour design basis battery discharge at an elevated temperature of 110°F, it would require more than two hours following charger power restoration for the hydrogen concentration to reach four percent. In addition, special features in the battery room supply air provide for ventilation under conditions where the normal battery room exhaust flow path is sealed. The special features provide a means for manual operator action that will occur within one hour of the beginning of the battery charging process to supplement ventilation to the applicable battery rooms under these conditions as necessary.

9.10.4.5 **Cable Tray Rooms**

The two cable tray rooms are large, open spaces directly above the control room. Each room is used as a cable-spreading area primarily for non-safety-related cables of its respective unit. The two Cable Tray Rooms contain one train of redundant safe shutdown equipment (Unit 1 Charging Pump Service Water Pump cables) for use during an Appendix R fire scenario outside the cable tray rooms. Adequate separation exists between the two trains. There are, however, a small number of non-safety-related cables that are important to plant operation, and a concrete cubicle containing the reactor protection system trip breakers and switchgear, located in each of the rooms. The non-safety-related cables are those associated with the interlocks between the reactor coolant pumps and the rod control system, and the interlocks between the main feedwater pumps and the motor-driven auxiliary feedwater pumps. The feed pump interlocks are part of a system that may be used for safe shutdown, since they function to provide the automatic start capability by the motor-driven auxiliary feedwater pumps. These pumps, however, may be started manually at the control board.

Two remote monitoring panels (RMP) are installed in the cable tray area of Unit 1. The RMP designated ASC RMP-1 monitors steam generator and pressurizer wide-range levels, Reactor Coolant System (RCS) wide-range pressures and RCS loop hot-leg temperatures. The RMP designated PNL-REM, monitors steam generator pressures, RCS cold-leg temperatures and source and wide-range neutron flux. Both units share each RMP; and the instrumentation from each unit is powered by the emergency power system of the opposite unit. This design feature is intended to assure that indications of these parameters from both units will be available even if a fire disables the emergency power system of either unit. See Section 7.7.2 for further information on the remote monitoring panels. These features and capabilities are part of the requirements of 10 CFR 50 Appendix R.

The Unit 2 communications system amplifier and associated cabling are located in the Unit 2 Cable Tray Room.

The combustible material in the rooms consists of a moderate amount of cable insulation.

An unmitigated fire in one of the cable tray rooms could damage the automatic start function of the motor-driven auxiliary feedwater pumps of one unit. However, the function could be performed manually at the control board in the control room. In addition, the turbine-driven auxiliary feedwater pump and the auxiliary feedwater pumps of the other unit would be available.

A fire in one of the concrete cubicles containing the reactor system trip breakers would not prevent a reactor scram because redundant components and circuits are located in separate enclosed panels and raceways. Due to the fail-safe nature of the reactor protection system design, a fire would not prevent a reactor scram.

Each cable tray room is bounded on all sides by concrete or concrete block, which provides an adequate fire barrier. The doors in this area are 3-hour-rated. All cable penetrations are sealed. Ventilation ducts that pass between the rooms and other plant areas are provided with fire dampers.

A smoke detection system is installed in each room along with an automatic heat-actuated total flooding CO_2 system. Portable extinguishers and manual hose stations are located in the turbine building to provide manual backup to the automatic suppression system. The rooms are relatively uncongested with adequate space for manual fire fighting.

The walls, ceiling and floor of the reactor trip switchgear cubicles are of concrete construction. The entrance to each cubicle is of a labyrinth design.

9.10.4.6 **Switchgear Rooms**

The switchgear rooms are large, open spaces located adjacent to the turbine building at the 58-feet elevation directly above the cable tray rooms. These rooms contain 480V and 4160V switchgear and other miscellaneous electrical equipment and associated cables. None of this equipment is considered safety-related. The Normal Switchgear Rooms are not considered safe shutdown areas by the Appendix R Report, but these areas do contain a limited number of alternate cables and equipment that support safe shutdown to address fires in other fire areas. Redundant trains of safe shutdown equipment are not affected by a fire in the Normal Switchgear Rooms.

The only combustible material in significant quantity in the switchgear rooms is the insulation on the moderate number of electrical cables present.

Due to the fire barriers separating the rooms and the absence of safety-related equipment, no adverse effects on plant safety are likely, even from an unmitigated fire.

The floors and walls of the switchgear rooms are constructed of concrete or concrete block, which provides an adequate fire barrier. The ceilings are also the roof of the building, an insulated metal deck. All penetrations in the floor to the cable tray rooms below are sealed.

9.10.4.7 Motor Control Center Rooms

The motor control center rooms for each unit are located above their respective outside containment penetration vaults. Each room contains 480V motor control centers, and the ventilation units for the cable vault and the motor control centers. None of this equipment is considered safety-related.

The combustible material consists of a small amount of cable insulation.

The only safety-related equipment in the motor control center rooms is the pressurizer heater panels. An unsuppressed fire in the rooms due to the combustion of the small quantity of cable insulation would not affect plant safety. Such a fire could disable the pressurizer heaters; however, the heaters are not credited for safe shutdown.

The floors, ceilings, and walls of the motor control center rooms are constructed of concrete or concrete block. The rooms each contain two non-fire-rated doors, one of which leads to the yard, and an open stairwell leading to the outside containment penetration vault located below.

A smoke detection system is installed in each room that alarms in the control room. Nozzles for a total-flooding CO_2 system are installed in each room. Heat detectors, located in the cable vault below the MCC room, actuate the automatic release of CO_2 into both rooms. Ventilation ducts leading to each room do not have fire dampers installed. However, the ventilation fan is shutdown in the event of actuation of the gas suppression system. Manual hose stations are located in the yard area and portable extinguishers are located near one entrance to each room. The room is relatively uncongested, with adequate space for manual fire fighting.

9.10.4.8 Auxiliary Building - Elevation 2 Ft.

This elevation of the auxiliary building is composed of large, open floor areas and separate equipment cubicles. There are separate concrete compartments for the safety-related seal-water heat exchanger, nonregenerative heat exchanger, and the demineralizers, and for the non-safety-related boron recovery system equipment and liquid waste system equipment. The six charging pumps (three per unit) are located in separate cubicles with concrete walls in the center of the floor area. The charging pump cubicles are completely enclosed on this elevation; access to the pump cubicles is on Elevation 13 ft. One charging pump is required for safe shutdown of both units.

Ventilation of the charging pump cubicles is provided during normal operation and after a LOCA. References 6 and 7 show that forced ventilation of the charging pump cubicles is not required after an Appendix R fire event.

Equipment in the open floor areas includes the four component cooling water pumps, classified as NSQ and pipes and valves for the Chemical and Volume Control System, classified as Safety Related. The component cooling water pumps are cross connected to serve either unit; one pump per unit is required for safe cold shutdown capability. The equipment cooled by the component cooling water system includes reactor coolant pump thermal barriers, residual heat removal pump seal coolers, reactor containment recirculation air coolers, spent-fuel pit coolers, and the excess letdown, nonregenerative, seal-water and residual heat removal heat exchangers.

The CCW pumps and the reactor containment piping penetration areas are ventilated by two fans which have their cables routed together through common fire areas. In this case the requirements of 10 CFR 50 Appendix R can be satisfied by the installation of temporary fans and ducting, since adequate time exists (i.e., several hours). No permanent modifications therefore are required to assure ventilation for these areas in the event of a postulated fire which disables normal ventilation. Appropriate procedures are in place to support this provision.

Cables for redundant divisions of safety-related and safe-shutdown equipment are routed through many areas of this elevation. Alternative safe shutdown capability in the event of a fire in this area is provided in accordance with 10 CFR 50 Appendix R.

The major combustible material on this elevation is cable insulation. Trash containers are used on this elevation. There is a lube-oil system associated with each charging pump, and minor amounts of lubricants in the other pumps.

A fire on this elevation could not damage redundant charging pumps because of the barriers between the individual pumps and between the pumps and other areas on this elevation. (See Exemption Request #1, 10 CFR 50 Appendix R Report.)

The component cooling water (CCW) pumps are mounted on pedestals and are separated by 15 feet. It is not expected that a postulated fire could damage more than one of these pumps because of the separation between pumps and the open hatch above the pumps, which would prevent local heat buildup. Nevertheless, a repair procedure has been developed in accordance with 10 CFR 50 Appendix R for repair of a CCW pump motor and cable.

Fire hose stations are provided on this elevation for manual fire fighting. Floor drains are available for removal of fire suppression water. Water spray shields have been provided on the CCW pump motors to minimize the possibility of water-induced damage.

9.10.4.9 **Auxiliary Building - Elevation 13 Ft.**

The six charging pumps are located on the 2-foot elevation in separate concrete cubicles accessible from the 13-foot elevation. The front walls of the cubicles are open on this elevation; the back walls of the three pumps for one unit face the back walls of three pumps for the other unit.

Three boric acid tanks and four boric acid transfer pumps are located in the open floor area. These tanks and pumps provide a source of boric acid for safe shutdown of both units. An alternative source of borated water is the refueling water storage tank, which is located outside the building.

Cables for redundant divisions of safety-related and safe-shutdown systems are located on this elevation. Alternative safe shutdown capability in the event of a fire in this area is provided in accordance with 10 CFR 50 Appendix R. The separation provided between safe shutdown components in this area is described in 10 CFR 50 Appendix R Report, Chapter 7, Exemption Requests. A repair procedure and replacement cable is available for replacing the component cooling water pump power cables in this area in the event of fire-induced damage.

The major combustible material on this elevation is cable insulation. A hydrogen line is routed in the overhead of this elevation to the volume control tanks on Elevation 27 ft. 6 in.

Although the front walls of the charging pump cubicles are open, it is not expected that a fire in one cubicle would affect adjacent charging pumps because of the floor-to-ceiling concrete barriers between pumps on this elevation. Also, because of the grating floor at Elevation 13 ft., charging pump lube-oil leakage would collect at Elevation 2 ft., where the cubicles are completely enclosed.

The four boric acid transfer pumps are 8 feet apart, and redundant pumps could be damaged by a transient combustible liquid spill; only minor amounts of lubricants are associated with the pumps themselves. Loss of redundant pumps would not prevent safe shutdown because of the alternate boration capability provided by direct supply of borated water from the refueling water storage tanks.

Fire hose stations are provided on this elevation for manual fire fighting. Floor drains are available for removal of fire suppression water. Portable fire extinguishers are provided on this elevation.

9.10.4.10 **Auxiliary Building - Elevation 27 Ft. 6 In.**

The safety-related equipment on this elevation includes the component cooling water surge tank, volume control tanks, and boric acid storage tanks. This equipment is not required for safe shutdown. The component cooling water surge tank and the volume control tanks are in separate concrete cubicles; the other safety-related equipment is located in the open floor area.

The nonsafety-related gaseous waste disposal equipment, solid waste disposal equipment, and some sampling system equipment are also located in separate cubicles on this elevation.

Cables for safety-related equipment are routed through many of the open floor areas on this elevation in conduit and in cable trays with corrugated metal top covers.

Combustible cable insulation and protective clothing in open drums are located in the open floor areas. A charcoal filter is located in the gaseous waste disposal room. A hydrogen pipeline enters the auxiliary building at the 2-foot level in vicinity of the SI lines supplying the high head SI pumps from which it is routed to the volume control tank area.

Fire hose stations and portable extinguishers are provided on this elevation for manual fire fighting. In addition, this elevation is accessible to yard hose facilities via two exterior doors in the general area and an exterior door from the drumming room. Floor drains are provided for removal of fire suppression water. The gaseous waste system charcoal filter can be air cooled if a temperature rise due to decay heat is detected by operators, or by heat detectors.

9.10.4.11 **Auxiliary Building - Elevation 45 Ft. 10 In.**

Components of the safety-related auxiliary building ventilation system (see Section 9.10.4.8), including redundant charcoal filter trains, are located on this elevation. Fuel building, decontamination building, and safeguards area ventilation equipment is also located on this elevation, along with the containment purge supply and exhaust fans. Safety-related cables in conduit and cable trays are routed through the area.

The combustible materials on this elevation include cable insulation, protective clothing in drums, and three charcoal filter units. Each of the two safety-related trains of the auxiliary building ventilation system filters contains about 2640 lb of charcoal.

Each of the safety-related charcoal filter units is in a separate metal enclosure and completely enclosed in separate concrete cubicles with metal closures for the ceilings and doorways. An unsuppressed fire in one filter would not propagate to the redundant unit, nor would it damage other safety-related equipment or cables. The inlet and outlet dampers can be shut to prevent radiation release, and the redundant unit can continue to operate. The non safety-related charcoal filter unit in the auxiliary building ventilation system is housed in a separate enclosure, independent of the other filter units and independent of safety-related equipment.

Fire hose stations and portable extinguishers are provided on this elevation for manual fire fighting. Floor drains are available for removal of fire suppression water.

The auxiliary building ventilation system safety-related charcoal filters are protected by separate total-flooding carbon dioxide suppression systems. These suppression systems are manually actuated, and are provided with heat detectors that will alarm in the control room at a filter temperature of 225°F. The non-safety-related charcoal filter unit is protected by an automatic water deluge system.

9.10.4.12 **Reactor Containment Buildings**

The reactor containment buildings for each unit are essentially identical structures. The containment building is divided by the polar crane wall into an outer annulus section and a central section. The central section is further subdivided into equipment cubicles that are connected to each other and to the outer annulus by open archways, grating floors, and unsealed penetrations. The entire containment can be considered a single fire area.

Safety-related equipment located inside containment includes the regenerative and excess letdown heat exchangers, steam generators, redundant residual heat removal pumps and heat exchangers, containment recirculation spray pumps and heat exchangers, safety injection accumulators, pressurizer, reactor vessel, and rod drive mechanism. Non-safety-related iodine charcoal filters and filtration fans are also located inside containment.

Power, control, and instrument cables for safety-related and non-safety-related equipment are located in the central compartments and are routed around the perimeter of the containment in the outer annulus. In some areas of the annulus, there are cables in open ladder trays with approximately 10 inches of separation between the trays in a stack. The trays are fitted with sheet metal covers that are raised approximately 1 inch above the top of the tray. Various safe-shutdown functions are served by the cables in containment. Radiant energy shields have been installed between primary and alternate safe shutdown instrumentation, and firestops have been installed in cable trays which are intervening combustibles between primary and alternate safe shutdown components. See NRC's Safety Evaluation dated 2/25/88 regarding exemption requested. A radiant energy shield is installed between the residual heat removal pump motors to satisfy 10 CFR 50, Appendix R requirements.

There are 200 gallons of lube-oil associated with each of the three reactor coolant pump motors. There are 175 gallons in the upper bearing reservoir and 25 gallons in the lower bearing reservoir. Combustible cable insulation is located in the containment annulus and in most of the central compartments. The fire loading due to cable insulation is particularly high in containment annulus penetration area. Each of the two iodine charcoal filter units contains about 170 lb of charcoal.

The combustible materials in containment, with the exception of the reactor coolant pump lube-oil, do not constitute a severe enough fire hazard to damage safety-related fluid system components such as heat exchangers, safety injection accumulators, the reactor vessel, and the pressurizer.

The iodine charcoal filters are enclosed in separate structures with 18-inch-thick concrete walls and roofs. An unmitigated filter fire would have no direct effect on safety-related equipment or cables.

Temperature sensors are provided on each reactor coolant pump to detect pump overheating. Portable fire extinguishers are provided outside the personnel hatch of the containment for manual fire fighting. A dry-type fire hose standpipe system has been installed in the containments for manual fire suppression capability. Heat and smoke detectors have been installed in the annulus cable penetration area for detection of a fire within the penetration area.

A reactor coolant pump motor oil collection system has been installed to ensure that oil leakage will not contact hot equipment and to reduce the possibility of a fire. Oil leakage from the reactor coolant pump motor lube-oil system is diverted by enclosures and open dams to a drain tank. This drain tank is sized to contain the total oil inventory of the motor.

The enclosures surround the following oil-bearing components that may leak and are fitted with covers to contain oil from leaks in pressurized lines and to keep foreign matter out of the drain. The oil-bearing components that require oil collection enclosures are:

1. Oil lift pumps (pressurized lines)

2. Oil cooler (pressurized lines and housing)
3. Oil level indicators
4. Oil fill and drain points
5. Flanged connections for the lower oil reservoir
6. Sight glasses
7. All flanged oil-bearing connections

In addition, open dams will drain any potential leakage from the gasketed joint between the upper oil pot housing and the support plate for the upper bearing.

The collection system is designed to withstand an SSE (Safe Shutdown Earthquake) and to collect lube oil from all potential pressurized and unpressurized leakage sites in the reactor coolant pump lube oil systems. Leakage is collected and drained to a vented closed container that can hold the entire lube oil system inventory for one RCP. A flame arrester is installed to minimize the hazard of fire flashback. The drain line is large enough to accommodate the largest potential oil leak.

9.10.4.13 **Containment Spray Pump and Auxiliary Feedwater Pump Buildings**

The containment spray pump and auxiliary feedwater pump buildings for each unit are essentially identical structures, each located adjacent to its unit's reactor containment building. The two containment spray pumps are located at ground level in one compartment. The two electric-motor-driven auxiliary feedwater pumps and the steam-turbine-driven auxiliary feedwater pump are located in an adjacent compartment. A grating is located above the auxiliary feedwater pumps. This floor grating provides access to the steam generator power operated relief valves, the main steam nonreturn valves, the main steam safety valves, and the main steam trip valves. A basement area under the pump compartments contains auxiliary feedwater booster pumps, service water pipes, and safety-related and non-safety-related cables. The cables are for the equipment in the building plus cables for the low-head safety injection pumps and recirculation spray pumps, and associated valves, located in the adjacent safeguards equipment building. The auxiliary feedwater pumps are required for safe shutdown in the event of a fire. The other equipment and cables are required to mitigate the consequences of a LOCA.

Small amounts of grease and oil are associated with each of the pumps. Some combustible cable insulation is located in the pump and valve areas. The basement contains a considerable quantity of cable insulation.

Alternative safe shutdown capability in the event of a fire in this area is provided in accordance with 10 CFR 50 Appendix R.

Loss of the steam generator power operated relief valves would not prevent safe shutdown, because the main steam safety valves would relieve steam pressure.

Loss of the auxiliary feedwater pumps for one unit would not prevent shutdown of that unit, because the auxiliary feedwater discharge lines for the two units are cross connected, and feedwater could be provided from the undamaged unit. The cross-connect valves are not located in the affected auxiliary feed water pump area and would not be incapacitated by a fire in that area.

Damage to redundant systems with components and cables in this building would not prevent safe shutdown, since a LOCA is not postulated simultaneously with a fire.

Portable extinguishers are provided for manual fire fighting. The fire hose at a yard hose cabinet could be used to fight a fire in parts of this building.

9.10.4.14 **Fuel Building**

The fuel building is bounded by the auxiliary building, decontamination building, and the two reactor containment buildings. The top surfaces of the spent-fuel pool and the new-fuel storage pit are located at Elevation 47 ft. 4 in. The spent-fuel pool cooling pumps and purification pumps are located below the new-fuel storage pit at Elevation 6 ft. 10 in. The motor control centers for the pumps are located on a stairway landing at Elevation 16 ft. 10 in. None of the equipment in the building is required for safe shutdown.

The combustible materials in the fuel building consist of small amounts of cables.

Because of the separation between combustibles and equipment, and the low fire loading, a fire in most areas of the building would cause minor damage. An unmitigated fire in the pump area could damage redundant spent-fuel pool cooling pumps. A cable fire could incapacitate redundant pumps. In the event of the loss of both pumps, the spent fuel could be cooled by makeup water supplied from the primary-grade water system, firewater system, or external supply source.

Fire hose stations and portable fire extinguishing equipment are provided inside the fuel building. For flood protection, a normally closed trip valve placed outside the building isolates the water to the building during normal operation. Existing hose racks are equipped with a remote control station to provide pressurization of the fire lines when demanded. Access for manual fire fighting is from the auxiliary building, decontamination building, and the yard area.

9.10.4.15 **Safeguards Equipment Buildings**

The safeguards equipment buildings for each unit are essentially identical structures, each located adjacent to its unit’s reactor containment building.

Access to the building is from the yard at Elevation 28 ft. 6 in. Ladders lead from this elevation down to the redundant containment recirculation spray pumps and the redundant low-head safety injection pumps. Each of these pumps is located in a separate pit. Valve operators and the cables for these pumps are located in a separate compartment on Elevation 19 ft. 6 in., accessible by ladder from Elevation 28 ft. 6 in. None of the equipment or cables in this building is required to achieve safe shutdown.

The combustible materials in this building are the cables in the valve operator area and grease in the pumps and valves.

The pumps are in separate cubicles with walls of 12-inch reinforced concrete; a fire in one pump cubicle would not affect other pumps. For a fire in this area, cables for both divisions could be lost. Safe shutdown would be accomplished using alternate equipment from the "opposite unit." Appendix R Safe Shutdown Analysis takes no credit for survival of the normal system equipment and cables in this area.

Portable fire extinguishing equipment is provided at Elevation 28 ft. 6 in. Fire hose would be available from the yard hose houses.

9.10.4.16 **Intake Structure**

The intake structure is located approximately 1.25 miles from the main plant buildings. Two separate compartments are located on top of the intake structure. One compartment contains non-safety-related cables, 4-kV switchgear, and motor control centers. The other compartment contains the three safety-related emergency service water pumps, and a fuel-oil tank cubicle. The fuel-oil tank supplies the diesel engines that drive the emergency service water pumps. The emergency service water pumps provide cooling water for plant shutdown in the event of a loss of offsite power. The three pumps are shared by both units.

The combustible material in the non-safety-related electrical equipment compartment is primarily cable insulation. There are 15 gallons of lube-oil associated with each emergency service water pump. The fuel-oil cubicle in the pump compartment contains a 4800-gallon fuel-oil tank.

A fire resulting in damage to all the cables in the electrical equipment compartment would have no effect on the ability to achieve safe shutdown in accordance with 10 CFR 50 Appendix R, since equipment and cables necessary to perform the shutdown function would be available outside of the fire area. An unmitigated fire in the electrical equipment compartment would not spread to the emergency service water pump compartment.

The walls between the fuel-oil day tank and the emergency service water pumps are 3-hour barriers.

Smoke detectors that alarm in the control room are provided in the electrical equipment compartment and in the emergency service water pump compartment. The fuel-oil tank cubicle is protected by a total-flooding carbon dioxide suppression system supplied by a bank of carbon dioxide cylinders in the pump room. The carbon dioxide system is automatically actuated by heat detectors or can be manually actuated. Actuation of the carbon dioxide system sounds a pre-discharge alarm and pneumatically closes vent dampers and releases doors when discharge occurs. Discharge is alarmed in the control room. After initial discharge, additional carbon dioxide may be released by manual operation of the system.

Portable and wheeled fire extinguishers are provided at the intake structure. The fire truck has a built in tank and also can draft water from nearby to supply fire suppression water. The fire truck and fire hose would be brought to the intake structure in response to a detector alarm or in response to a call from a plant operator, who inspects the area once per shift.

9.10.4.17 **Mechanical Equipment Room No. 3**

Mechanical equipment room No. 3 is located adjacent to the Unit 2 relay room and the train "2H" emergency switchgear room. Three safety-related air-conditioning chillers and chiller circulating pumps are located in this room. If all three air conditioning chillers are simultaneously disabled in mechanical equipment room No. 3, there are two chillers in mechanical room No. 5 that are available to maintain cooling in the main control room and emergency switchgear and relay rooms.

Mechanical equipment room No. 3 also contains two charging pump service water pumps. One pump is required to support operation of two charging pumps to achieve and maintain safe hot shutdown and safe cold shutdown for both units. In the event of a fire in this area, service water to the charging pumps would be provided by one of the charging pump service water (CPSW) pumps located in Mechanical Equipment Room No. 4 in the turbine building basement, which is independent of this area. Cables for the equipment are located in conduits and cable trays in this room.

One wall of this room is shared with the turbine building and with the charging pump service water pump room; however, a fire in the turbine building cannot affect safe shutdown equipment in mechanical equipment room No. 3 because 3-hour-rated fire barriers are used to separate MER-3 from the turbine building.

Combustible material in the room includes the approximately 10 gallons of lube-oil associated with each of the three chiller units and a moderate amount of combustible cable insulation.

Portable fire extinguishers are provided in the room and nearby for manual fire suppression. A fire hose station is located nearby in the turbine building, but the hose may not reach the mechanical equipment room. A floor drain is provided in the room for removal of fire suppression water. The door to the emergency switchgear room is curbed to prevent the spread of a lube-oil fire to the switchgear room.

9.10.4.18 **Mechanical Equipment Room No. 4**

MER-4 is a separate pump room located on the safety-related, Seismic Category I, service building foundation slab, which abuts the adjacent turbine building foundation slab. The doorway to MER-4 is accessed from the 9 ft.-6 in. elevation of the Unit 2 turbine building. MER-4 provides tornado missile protection to safety-related equipment housed within. MER-4 houses two charging pump service water pumps 1-SW-P-10A and 2-SW-P-10A. One pump 1-SW-P-10A is required to support operation of two charging pumps to achieve and maintain safe hot shutdown and safe cold shutdown for both units. Smoke detectors are installed within MER-4 in accordance with National Fire Protection Association (NFPA) Standard 72.

The north wall, shared with MER-3, has a 3-hour fire rating. The remaining walls, which are 3-hour fire rated, separate MER-4 from the turbine building.

The amount of combustible material in the room is low and consists of fiberglass piping and grease. A fire hose station is provided outside the room and in the nearby area for manual fire suppression.

9.10.4.19 **Turbine Building**

The turbine building is a steel-framed structure with the lower portions of the exterior walls constructed of masonry and the upper portions of uninsulated metal siding. The roof is metal decking covered with insulation and membrane roofing. The building is divided into two identical sections, except for the operating floor, each measuring approximately 330 feet long by 150 feet wide, housing the turbines and generators for Units 1 and 2. Each section has three levels, situated at Elevations 9 ft. 6 in., 29 ft. 6 in., and 58 ft. 6 in. The operating floor is reinforced concrete, supported on steel framing. The mezzanine level and platforms are steel-framed, with metal floor grating. Stairways between floors are constructed of metal grating.

The turbine building is bounded on the west side by the office building and on the south side by exposed exterior walls. The north side shares a common wall with a portion of the service building that contains the safety-related diesel-generator rooms, emergency switchgear rooms, control room, and battery room 2B. Other non-safety-related areas of the service building opening off the turbine building include the shop area, labs, locker, and wash rooms. The turbine building is bounded on the east side by the condensate polishing building.

Safety-related equipment located within the turbine building includes control room and switchgear area emergency ventilating units, component cooling water heat exchangers, service water valves, circulating water valves, and charging pump service water subsystem valves. Most of this equipment is located at Elevation 9 ft. 6 in. Circulating water valves isolate the main condensers from the intake canal to conserve water in the canal for shutdown. Components required for safe shutdown are separated in accordance with the requirements of 10 CFR 50 Appendix R.

Cable trays are located at all elevations of the turbine building, although most are located at Elevations 29 ft. 6 in. and 9 ft. 6 in.

Normal combustibles in the turbine building include the lubricating oil and hydrogen gas contained within the turbine generator. Combustibles at the 29 feet 6 inches elevation include the 21,000-gallon turbine oil reservoir and coolers, heavy concentrations of cabling, hydrogen piping, and several 55-gallon drums of flammable materials, including used oil and grease. The combustibles at Elevation 9 ft. 6 in. include two 22,000-gallon turbine lube-oil storage tanks enclosed within a separate room. Other combustibles at this elevation include the turbine oil conditioner unit, containing about 330 gallons of oil, the hydrogen seal oil unit, containing about 70 gallons of oil, redundant trains of safety-related cabling, and various transient combustible materials including lubricants, welding gas, lumber, and polyethylene plastic film used to isolate and protect equipment during maintenance procedures.

The operating floor of the turbine building is an open area containing both the Unit 1 and 2 steam turbines and generators. A 12-inch block wall is provided to separate Units 1 and 2 below the operating floor. The turbine building is separated from the safety-related portions of the service building by reinforced-concrete walls. Other areas of the service building are separated from the turbine building by 12-inch-thick masonry walls.

The 21,000-gallon turbine oil reservoirs and coolers at Elevation 29 ft. 6 in. are provided with 3.5-foot-high concrete curbs, which are capable of containing the entire contents of the reservoirs. The turbine lube-oil tanks, containing 44,000 gallons, are located at Elevation 9 ft. 6 in. within the turbine lube-oil rooms, and are arranged with diking adequate to contain the entire contents of the tanks. The room is penetrated by a 3-hour sliding steel fire door on the north wall and an unrated door in the east wall. The hydrogen seal-oil units are located at Elevation 9 ft. 6 in. and contain approximately 70 gallons of oil. These units are not provided with curbing, although a drainage trench surrounds the units. The turbine lube-oil conditioners, which contain 330 gallons of oil, are located at Elevation 9 ft. 6 in. The units are provided with dikes adequate to contain the entire amount of oil contained within the equipment.

The hydrogen seal-oil units, the turbine oil reservoir and coolers, and the turbine lube oil conditioners are protected by deluge systems actuated manually at the control room or locally. These areas are also provided with thermal fire detectors with annunciation in the control room. The turbine lube-oil rooms are protected by an automatic sprinkler system with alarm indication in the control room.

The turbine generators contain lube oil and hydrogen at the bearing enclosures. These areas are provided with fixed, low-pressure carbon dioxide suppression systems automatically initiated by temperature detectors when the enclosure temperatures exceed 450°F. The systems may also be manually initiated locally.

Sprinkler protection is provided at all levels of the turbine building except for the operating deck. The sprinklers inside the turbine deck security office (TDSO) are the only sprinklers above the turbine operating deck.

Backup fire-fighting capability is provided by manual hose stations located in various areas of the building and from the hydrant/hose houses in the yard, as well as portable extinguishers.

9.10.4.20 **Diesel-Generator Rooms**

There are three adjacent identical diesel-generator rooms, each measuring approximately 28 feet wide by 58 feet long by 16 feet high. The rooms are located in the service building in a one-story, reinforced-concrete structure.

Each room contains a diesel-driven generator, day tank, starting air compressor, air storage tank, batteries, and a control panel.

The combustibles in each room consist of approximately 1100 gallons of diesel fuel oil and about 500 gallons of lubricating oil. Other minor quantities of combustible materials consist of the battery cases and cabling. The day tanks are supplied from the yard by transfer pumps started by level switches in the day tanks.

An unmitigated fire in one of the emergency diesel-generator rooms would result in the loss of function of one emergency diesel generator.

The diesel-generator rooms are enclosed with 2-foot-thick reinforced-concrete walls and ceilings with an equivalent fire rating in excess of 3 hours. The 3-hour walls separating the diesel-generator rooms are not penetrated by doors or ducts. The rooms are accessed through fire rated doors from the turbine building.

A fixed, manually actuated, total-flooding carbon dioxide suppression system is provided in the emergency diesel-generator rooms. Two thermostats located near the ceiling initiate an alarm in the control room when the temperature exceeds 190°F. The carbon dioxide suppression system can be actuated from a push-button station in the control room or from manual break-glass stations at the entrances to each room. Initiation of the carbon dioxide suppression system is arranged to automatically close doors to the area and trip the room exhaust fan, but does not shut the overhead air intake louvers. Prior to manually actuating the suppression system, the ventilation system must be manually shut down.

Backup fire-fighting capability is provided by a dry-chemical and a carbon dioxide portable extinguisher in each diesel-generator room. Manual hose stations serving this area are provided in the turbine building.

Venting of smoke from these rooms, as well as disposal of large quantities of fire-fighting water, can be made through the exterior doors.

Because the three redundant diesel-generator rooms are completely separated from each other, with no open penetrations through the walls separating the units, the potential for an unmitigated fire in one unit spreading to the other units is small.

9.10.4.21 **Compressed-Gas Storage Areas**

There is no safety-related equipment in these areas.

Compressed gases stored in the yard area include hydrogen in cylinders stored under a protective roof, with concrete walls on three sides and the fourth side open. Main generator hydrogen storage is in tanks set on a concrete pad. Welding gas, including oxygen and acetylene cylinders, is also stored on a concrete pad. Compressed-gas cylinders are also stored in the yard adjacent to the auxiliary building.

A fire in any of these areas would result in the loss of all the stored compressed gas in that area but would not affect safety-related areas.

Fire protection provisions for the combustible gas main storage area include adequate separation distance from safety-related equipment, and manual fire fighting utilizing the hydrants and equipment in the hose houses.

The separation distances and manual suppression capability are adequate to prevent a fire in compressed-gas storage areas from affecting safety-related equipment.

9.10.4.22 **Transformer Area**

There is no safety-related equipment in this area.

There is a large amount of oil in the transformer units, which include the main and station service transformers for Units 1 and 2.

A fire in one of the transformers would cause the loss of function of at least one transformer, but would not have any effect on the ability to safely shut down the plant.

Each of the transformers is protected by an automatic water spray suppression system actuated by heat detectors. Hose lines from nearby hose houses are available for manual suppression.

The transformers are separated from each other by 12-inch-thick concrete fire walls 19 feet tall. The transformers are located 35 feet away from the turbine building. The units sit on a bed of crushed stone with a 6-inch-high dike surrounding each transformer. The crushed stone pits are sized to the full volume of oil released from a transformer, preventing the oil from spreading.

The fire detection and suppression equipment are adequate to control a fire in the transformer area.

9.10.4.23 **Fuel-Oil Pump Houses and Storage Tanks**

The fuel-oil pump houses and tanks are located at the northeast corner of the yard. The system consists of one 210,000-gallons aboveground storage tank, two 20,000-gallon underground tanks, and two identical pump houses. The pump houses are located below grade and are separated from each other by an 8-inch-thick concrete wall. The interiors of the pump houses are reached from grade via steel ladders in a hatchway. Each pump house measures approximately 17 feet by 17 feet in area, with a 16-foot-high ceiling. Each pump house contains three fuel-oil transfer pumps and a 275-gallon drain tank. Each pump house contains one of the redundant safety-related pumps that supplies the diesel-generator day tanks.

The combustibles in each of the pump houses consist of approximately 300 gallons of fuel-oil contained in the drain tank, pumps, and piping. The maximum combustible loading of the aboveground fuel-oil storage tank is 210,000 gallons.

An unmitigated fire in one of the fuel-oil pump houses could damage or destroy all the equipment within the enclosure. A fire in one of these pump houses, however, would not affect the adjacent pump house containing redundant equipment. A leak in the aboveground oil storage tank would be contained within the diked area and would not affect other areas of the plant. The two underground 20,000-gallon fuel-oil tanks are not subject to a fire.

The two fuel-oil pump houses are located below grade adjacent to each other, and are separated by a 8-inch-thick reinforced-concrete wall with 3-hour equivalent fire rating. Ventilation to these areas is provided by fans and concrete ducts.

Fire suppression for the fuel-oil pump houses is provided by a fixed high-pressure carbon dioxide extinguishing system. The carbon dioxide system is automatically actuated by heat detectors or can be manually actuated. Initiation of the system shuts off the ventilation fans and sounds a predischarge alarm. Following a 30-second delay, carbon dioxide is discharged into the room and the discharge is alarmed and annunciated in the control room. After the initial discharge, additional release of carbon dioxide must be manually actuated. The system has a lockout valve for personnel safety which alarms in the control room when the system is locked out. Backup manual fire suppression is provided by a nearby hydrant and hose house with provisions for foam application.

The 210,000-gallon aboveground steel fuel-oil storage tank is encircled with an 8.5-foot-high impoundment wall constructed of 12-inch-thick reinforced concrete and sized to the entire 210,000-gallon capacity of the fuel-oil storage tank. The fuel tank is also provided with a fixed pipe foam application system arranged to deliver foam/water solution to the topside of the tank, utilizing a foam eductor and foam concentrate stored in an enclosure located near the tank. Manual application of foam is possible by use of a foam hose line and nozzle provided on the fire engine.

The two 20,000-gallon underground fuel-oil storage tanks are not provided with any fire protection systems. The fire protection features for the two underground fuel-oil pump houses are adequate.

The impoundment diked area and the foam application suppression system protecting the 210,000-gallon aboveground fuel-oil storage tank is adequate. Provisions for manual fire fighting using hydrants and hose lines are also adequate.

9.10.4.24 **Fire-Pump House**

The fire-pump house is a free-standing, reinforced-concrete building approximately 35 feet wide by 53 feet long, situated in the southwest portion of the yard. The building is separated by a wall with a metal door, forming two separate rooms. One room contains the electric-motor-driven fire pump, motor control center, surge tank, and two small water booster pumps. The other room contains the diesel-engine-driven fire pump, fuel tank, pump controller, batteries, air compressor, and water tanks.

None of the equipment at this location is safety-related.

The major combustibles in this building consist of approximately 460 gallons of diesel fuel in the day tank, a minor quantity of lube-oil in the diesel engine pump, and small quantities of cabling.

The reinforced-concrete exterior walls and the wall separating the two rooms have an equivalent fire rating in excess of 3 hours. The door in this wall is fire rated. Floor drains are provided at each of the two fire-pump rooms, which are connected to a common drain line, but the drains in the diesel fire pump room have been plugged.

An outside hydrant and hose house is located approximately 35 feet from the building and is the primary provision for fighting a fire in this building. Three Class C extinguishers are provided in the electric-motor-driven fire-pump room at the doorway between the two rooms.

Ventilation in the two fire-pump rooms is provided by large air intake screens for the diesel engine and double doors to the outside from the electric-driven fire-pump room.

9.10.4.25 **Auxiliary Boiler Room**

The auxiliary boiler room measures approximately 45 feet wide by 60 feet long and contains the two oil-fired auxiliary boilers with associated equipment. The room is located at the northeast corner of the turbine building, and contains no safety-related equipment.

The combustibles in this room consist of fuel-oil in the burner supply lines and minor quantities of cabling and waste materials.

The floor drainage system in the auxiliary boiler room does not communicate with other areas of the plant; therefore, fuel oil leakage in the room cannot spread to other plant areas via the floor drainage system.

An unmitigated fire in this area would not affect safe shutdown. Because of the corrugated metal wall panels at each side of the room, an explosion would be safely vented outside, and safe-shutdown capability would not be affected.

Primary fire protection for this area is provided by automatic sprinklers. Secondary fire-fighting capability is provided by a manual hose station and two 20-lb dry-chemical extinguishers located within the room. An outside hydrant is located approximately 80 feet away.

The existing fire protection systems are adequate for the hazards presented in this area.

9.10.4.26 Main Switchyard, Surry Nuclear Information Center (SNIC) and Gravel Neck Combustion Turbines

A fire main and accompanying hydrants and hose houses have been installed in the storage area, main switchyard area, SNIC, and Gravel Neck combustion turbine area to provide a greater level of fire protection. The fire main is suppled with water from the existing fire main, which runs alongside the main warehouse.

Hose houses in the area of the Gravel Neck combustion turbine Units 1 and 2 (original gas turbines) are equipped with a foam unit consisting of tanks of foam solution, fire hose, foam proportioner, and nozzles.

The 10-inch fire main routed to the Gravel Neck combustion turbine Units 3, 4, 5, and 6 supplies fire hydrants and a 1500 gpm booster pump with fire water. The booster pump supplies fire hydrants, a foam house for foam discharge into the fuel tanks, foam-type fire hose suppression systems, deluge systems for transformers, and a sprinkler system. Blanked flange and tee provisions will permit future facility expansion.

The underground fire main in this area is classified as a Category III structure and the design is consistent with the non-seismic classification. The system was designed to the requirements of NFPA 24.

9.10.4.27 Mechanical Equipment Room No. 5

Mechanical equipment room No. 5 (MER-5) is located at the 9 ft.-6 in. elevation of the Unit 2 turbine building. MER-5 houses two chillers, associated chiller auxiliaries, and electrical equipment. Smoke detectors are installed within MER-5 and are spaced in accordance with National Fire Protection Association (NFPA) Standard 72E.

Appendix R isolation panel AS-2 is located in the electrical area of MER-5. In the event that the Control Room becomes uninhabitable, chillers 1-VS-E-4D and 4E control power can be transferred, and the chillers and their associated equipment can be locally controlled.

One wall of this room is shared with the turbine building. A fire in the turbine building cannot affect safety-related equipment in MER-5 because the walls are constructed of 2-foot thick concrete, and the doors are 3-hour fire-rated. Two 3-hour fire-rated fire dampers are used to seal the duct openings in the roof.

The major combustible material in the room is the lube oil associated with each of the two chiller units. There is also a moderate amount of combustible cable insulation in the room. Portable fire extinguishers are provided in the room and in the nearby area for manual fire suppression.

Equipment in MER-5 is protected from turbine building flooding by the presence of flood dikes at the doors which provide access to the room. The electrical equipment is protected by a

2-foot high wall separating the electrical equipment from the mechanical room and turbine building sump. Backflow from the turbine building drains is prevented by means of backflow preventers installed downstream of the mechanical room drains.

9.10.4.28 **Condensate Polishing Building and Maintenance Building**

The Condensate Polishing Building and Maintenance Building are located east of the Turbine Building and contain various pieces of equipment for processing secondary water and maintenance activities. These areas contain no safe shutdown equipment.

The combustibles in this room consist of lube oil associated with pumps and motors, cables, and other various combustibles associated with maintenance.

An unmitigated fire in this area would not affect safe shutdown. This area is separate from safe shutdown components located in the Turbine Building and other plant areas.

Primary fire protection for this area is provided by automatic sprinklers. Secondary fire-fighting capability is provided by manual hose stations and fire extinguishers located within the rooms. The Condensate Polishing Building is also equipped with smoke detection.

9.10.5 Tests and Inspections

Tests and inspections of fire protection systems are performed in accordance with the Technical Requirements Manual.

9.10.6 Administrative Controls

The fire protection program, previously known as the Fire Protection Plan, includes sections which discuss Fire Brigade organization, structure, training, and records.

Ignition sources used in both safety-related and non-safety-related areas of the station require written authorization from the Supervisor - Nuclear Site Safety except for exempted areas, such as workshops, as delineated in the program. Ignition sources shall be removed from safety-related areas at the end of each workday.

Location of transient combustibles in safety-related areas requires written authorization from the Supervisor - Nuclear Site Safety.

9.10 REFERENCES

1. NFPA 12A, *Halon 1301 Fire Extinguishing Systems*, 1980 Edition.
2. Generic Letter 83-33, *NRC Positions on Certain Requirements of Appendix R to 10 CFR 50.*
3. NUREG/CR-3656, *Evaluation of Suppression Methods for Electrical Cable Fires*.
4. Inspection Report (IR) 50-280, -281/87-07, dated 6/17/87.

5. Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Response to Generic Letter 88-2, Supplement 4, *Individual Plant Examination of Non-Seismic External Events and Fires*, Serial No. 94-302.
6. Surry Engineering Transmittal ET-S-08-0041, *Evaluation of Scaffolding Used to Operate 2-VS-MOD-200A/B*.
7. Surry Engineering Technical Evaluation ETE-SU-2010-011, *Evaluation of Filtered Exhaust Fan 1-VS-F-58B Usage in Appendix R Scenarios*.

9.10 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FB-2A	Arrangement: Fire Protection

Table 9.10-1
FIRE PROTECTION SYSTEM COMPONENT DESIGN DATA

Fire pumps	
Number	2 (1 motor and 1 engine-driven)
Type	Horizontal centrifugal
Rated Motor horsepower	250 hp
Rated Engine horsepower	332 hp
Capacity, each	2500 gpm
Head at rated capacity	231 ft (minimum)
Design pressure	175 psig
Design temperature	80°F
Seal	Packing
Material	
Pump casing	Cast iron
Shaft	Steel
Impeller	Bronze
Earthquake design	Class I (engine-driven pump only)
Pressure maintenance pump	
Number	1
Type	Horizontal radial vane
Motor horsepower	10.0 hp
Capacity	30 gpm
Head at rated capacity	252 ft
Design pressure	125 psig
Design temperature	90°F
Seal	Mechanical
Material	
Pump casing	Cast iron
Shaft	316 Stainless Steel
Impeller	316 Stainless Steel
Hydropneumatic tank	
Number	1
Type	Cylindrical, vertical
Capacity	475 gal
Design pressure	200 psig
Design temperature	100°F
Material	Carbon steel
Design code	ASME VIII

Table 9.10-1 (CONTINUED)
FIRE PROTECTION SYSTEM COMPONENT DESIGN DATA

Fire-pump oil tank	
Number	1
Type	Round, horizontal
Capacity	460 gal
Design pressure	Atmospheric
Design temperature	90°F
Material	Steel
Design code	NFPA-30
Earthquake design	Class I
Water storage tank	
Number	2
Type	Cylindrical, vertical
Capacity	250,000 reserved gal
Design pressure	Atmospheric
Design temperature	5°F
Material	Carbon steel
Design code	NFPA No. 22
Air compressor	
Number	1
Capacity	8.11 scfm
Discharge pressure	100 psig
Low-pressure carbon dioxide storage tank	
Number	1
Type	Cylindrical, horizontal
Capacity	17 tons
Operating pressure	295-305 psig
Design pressure	363 psig
Design temperature	0°F
Material	Steel
Design code	ASME VIII
Halon 1301 Storage Cylinders - Emergency Switchgear Rooms	
Number	26 (8 for Unit 1, 9 for Unit 2, 9 spare)
Type	Cylinder, vertical
Capacity	335 lb (18 cylinders) & 240 lb (8 cylinders)
Design Pressure	360 psig
Design Temperature	70°F
Material	Steel
Design Code	NFPA 12A

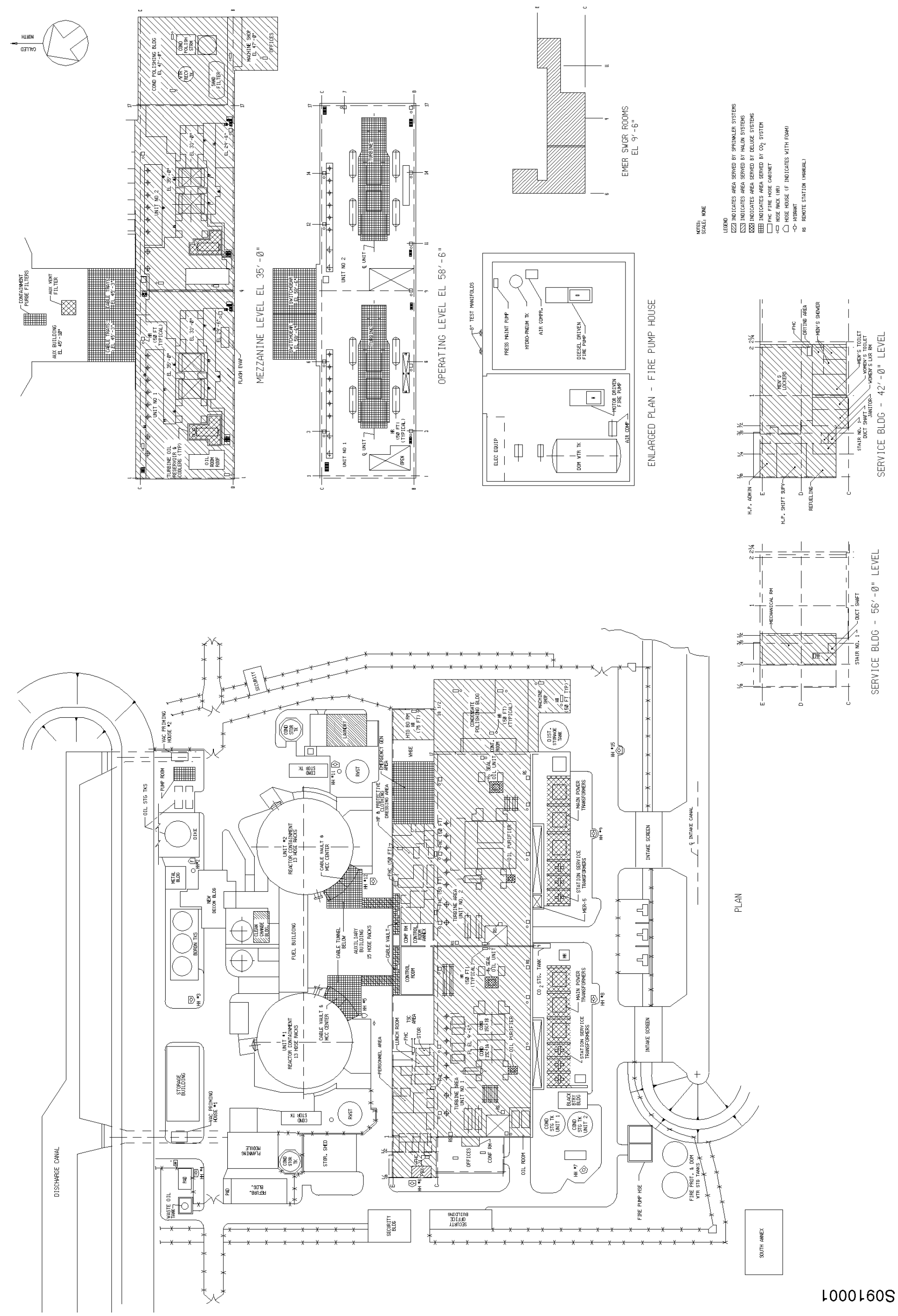


Figure 9.10-1
FIRE PROTECTION SYSTEM ARRANGEMENT

9.11 WATER SUPPLY AND TREATMENT SYSTEMS

9.11.1 Well-Water Supply System

The well-water supply system provides makeup water to the fire protection and domestic water storage tanks. Water from the fire protection and domestic water storage tanks is then used to supply the hydropneumatic tank in the potable water system and the fire protection system. The well-water supply system is shown on Figure 9.11-1.

There are three cased water wells located south of the site, wells B, C, and E as shown on Figure 15.1-1. Each well has a 200-gpm submersible pump discharging to a wellwater storage tank. Each well pump has a separate underground discharge line that is interconnected at the storage tank. Centrifugal-type well-water transfer pumps deliver water from the storage tank to consuming systems as required.

The well-water supply system is designed to be automatically or manually controlled.

9.11.2 Domestic Water Supply System

A 4000-gallon hydropneumatic tank, located in the fire-pump house, is provided for the domestic water supply system. Pressure in the hydropneumatic tank is maintained at 40 to 60 psig by a pressure system, consisting of a pressure-level regulator, air compressor, and related controls and accessories. Hypochlorinator equipment provides a means of chlorinating the domestic water supply. Piping from the hydropneumatic tank supplies cold water to safety showers, drinking water coolers, hot-water storage tanks, and domestic cold water throughout the station.

Domestic water supply component design data are given in Table 9.11-1.

9.11.3 Make-Up Water System

The make-up water system is shown on Figure 9.11-2 and Reference Drawings 1, 2, 3, 4, and 6. The system consists of equipment for the production of high-purity water by demineralizing well water for makeup to the various station systems. The flash evaporation system (Reference Drawing 1) is no longer used to treat water, however, the equipment remains installed in the plant.

Well water is stored in the Fire Protection and Domestic Storage Tank. The Condensate Polishing System is available to provide supplementary chemical treatment of condensate for feedwater conditioning. High-purity water is pumped to the primary-water storage tanks (Section 9.1) for reactor plant makeup, and to the condensate storage tank for secondary plant makeup.

The fire protection system is discussed in Section 9.10.

9.11 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-077A	Flow/Valve Operating Numbers Diagram: Flash Evaporator System, Unit 1
	11548-FM-077A	Flow/Valve Operating Numbers Diagram: Flash Evaporator System, Unit 2
2.	11448-FM-077B	Flow/Valve Operating Numbers Diagram: Flash Evaporator System, Unit 1
3.	11448-FM-077C	Flow/Valve Operating Numbers Diagram: River Water Filtration System, Unit 1
4.	11448-FM-077F	Flow/Valve Operating Numbers Diagram: Demineralizer Regeneration System, Unit 1
5.	11448-FM-077E	Flow/Valve Operating Numbers Diagram: Waste Neutralization System, Unit 1
6.	11548-FM-077D	Flow/Valve Operating Numbers Diagram: Distillate Storage and Transfer System, Unit 2

Table 9.11-1
DOMESTIC WATER SUPPLY COMPONENT DESIGN DATA

Hydropneumatic tank	
Number	1
Type	Cylindrical, horizontal
Capacity	4000 gal
Design pressure	100 psig
Design temperature	100°F
Material	Carbon steel
Design code	ASME VIII
Water booster pump	
Number	2
Type	Centrifugal, inline
Motor horsepower	15 hp
Capacity	300 gpm
Head at rated capacity	139 ft
Design pressure	135 psig
Design temperature	90°F
Seal	Packing
Material	
Pump casing	Cast iron
Shaft	SS 316
Impeller	Bronze
Air compressor	
Number	1
Capacity	8.11 scfm
Discharge pressure	60 psig

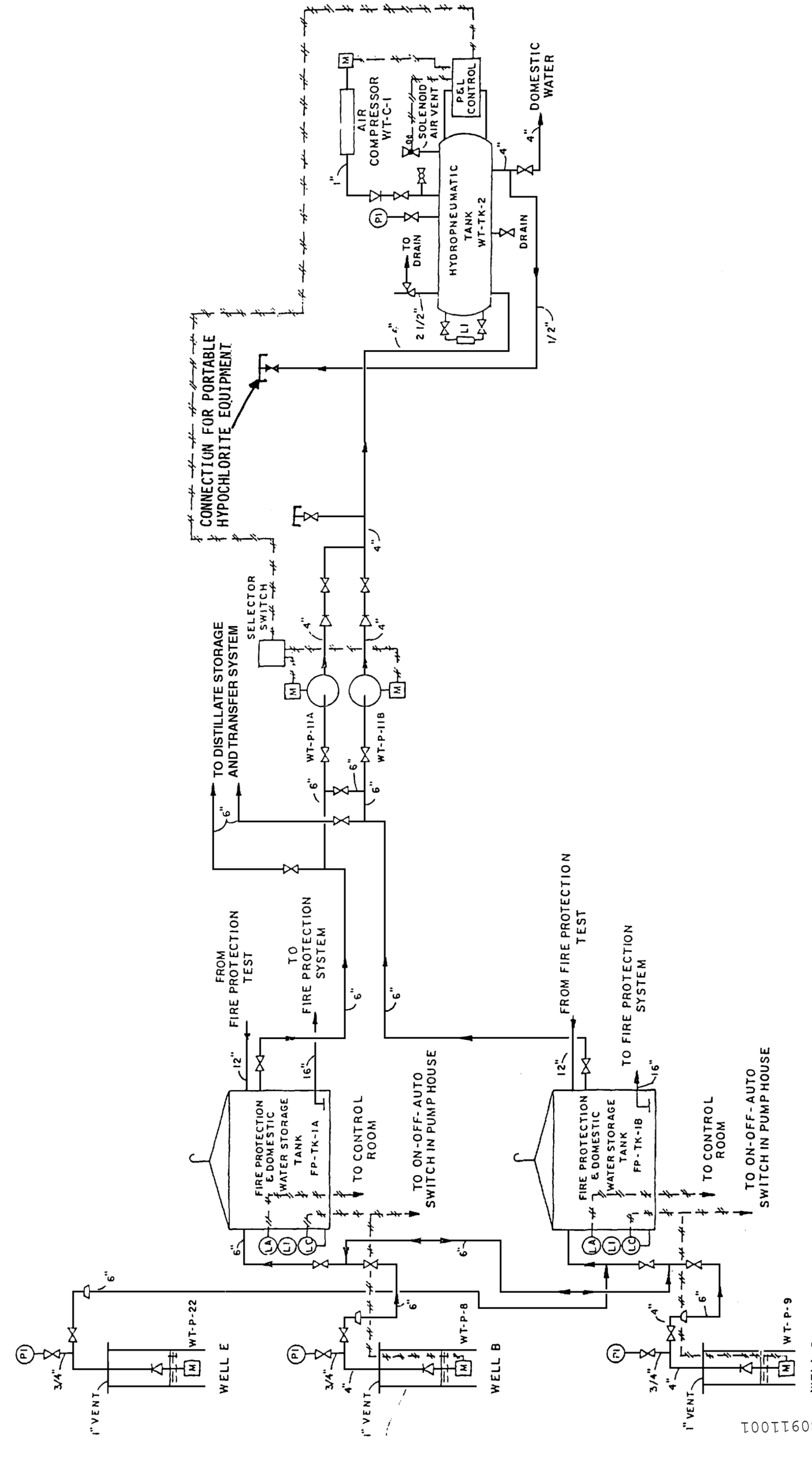
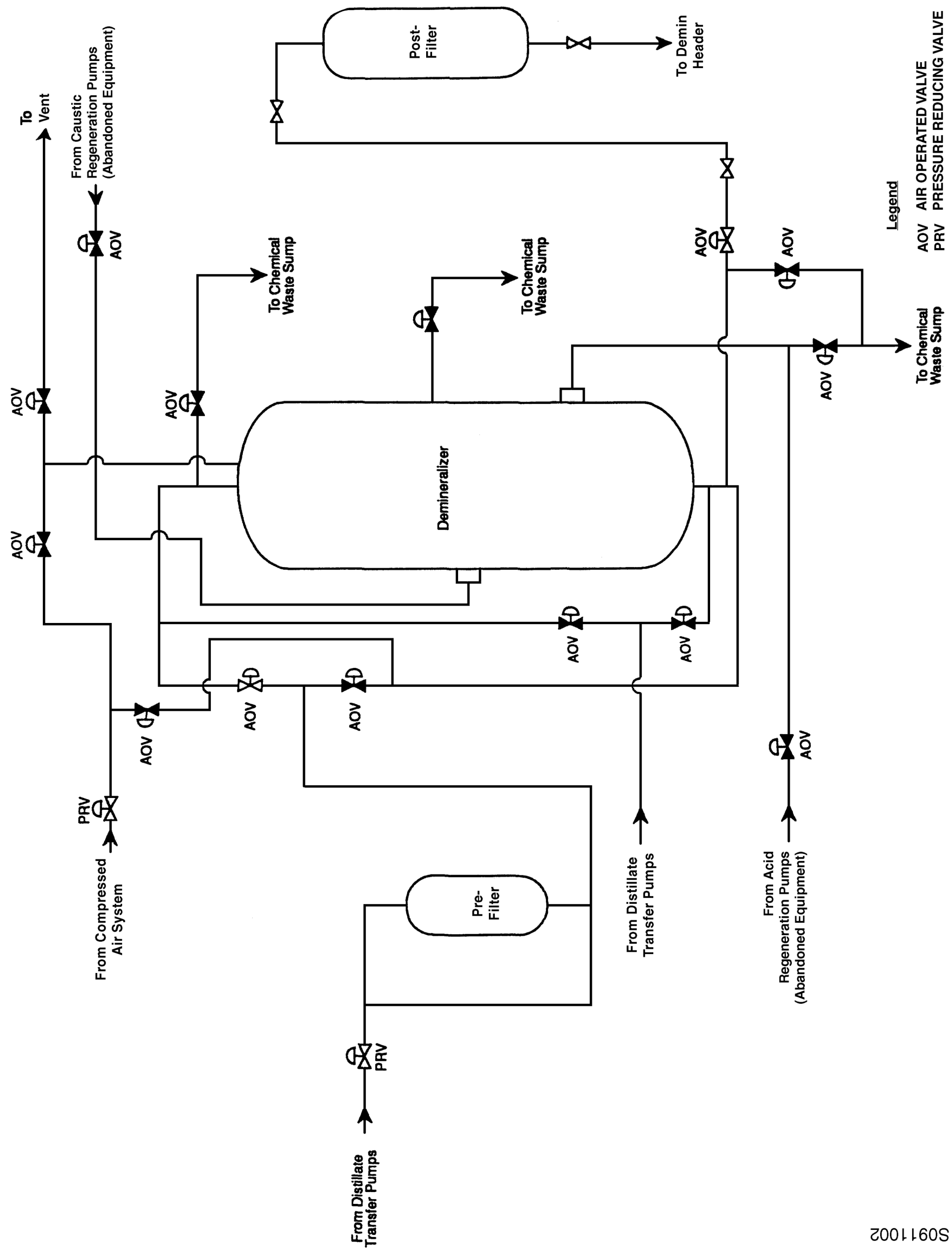


Figure 9.11-1
WELL WATER SYSTEM

Figure 9.11-2
DEMINERALIZERS



Intentionally Blank

9.12 FUEL HANDLING SYSTEM

The fuel handling system provides a safe, effective means of transporting and handling fuel from the time it reaches the station in an unirradiated condition until it leaves the station after postirradiation cooling.

The system is designed to minimize the possibility of mishandling that could cause fuel damage and potential fission product release.

The fuel handling system consists basically of:

1. The reactor cavities, one in each unit’s containment structure, which are flooded only during unit shutdown for refueling, and a manipulator crane for each unit.
2. The spent fuel storage pool, which is maintained full of borated water and is always accessible to operating personnel, and a movable platform with hoists. It is shared by both units.
3. The fuel transfer system for each unit, which consists of an underwater conveyor that carries the fuel from the reactor cavity, through the containment wall, and into the spent fuel storage pit.

9.12.1 Design Bases

The fuel handling system and areas comply with appropriate criteria, as discussed in Section 1.4. The applicable criteria are:

Criterion 4—Sharing of Systems

Criterion 18—Monitoring Fuel and Waste Storage

Criterion 66—Prevention of Fuel Storage Criticality

Criterion 67—Fuel and Waste Storage Decay Heat

Criterion 68—Fuel and Waste Storage Radiation Shielding

9.12.2 System Design and Operation

Each reactor is refueled with equipment designed to handle the spent fuel under water from the time it leaves the reactor until it is placed in a cask for shipment and/or storage on site. Boric acid is present as required in the water to ensure subcritical conditions during all phases of the refueling process.

In each reactor cavity, in each unit’s containment, fuel is removed from the reactor vessel, transferred through the water, and then placed in the fuel transfer system by a manipulator crane. There is a separate fuel transfer system with each unit. It is then transferred through the fuel transfer tube to the spent fuel pool. Fuel is removed from the fuel transfer system and placed in storage racks with a long manual tool suspended from an overhead electric monorail hoist on a bridge structure mounted on a movable platform that runs over the new fuel and spent fuel storage areas, which are common to the two units. After a sufficient decay period, the fuel may be removed from storage and loaded into a cask for removal to the onsite Independent Spent Fuel Storage Installation pad or to offsite facilities.

New fuel assemblies are received and stored in racks in the new fuel storage area. The new fuel storage area does not contain any water. New fuel is delivered to the reactor by transferring it from the new fuel storage area to the spent fuel storage pool and taking it through the transfer system. The new fuel storage area is sized for storing two-thirds of a core plus 20%, as detailed in Table 9.12-1. A portion of the fuel for the initial core loading was temporarily stored in the spent fuel pool.

The reactor cavity and spent fuel pool are reinforced-concrete structures with butt-welded stainless steel plate liners. These concrete structures are designed as Seismic Class I to withstand the anticipated earthquake loadings.

All liner butt welds conform strictly to the requirements of Section IX of the ASME Code, and are provided with test chambers to check for leaktightness.

Fuel-handling data are given in Table 9.12-1.

9.12.3 Fuel-Handling Structures

9.12.3.1 Refueling Cavities

Each reactor cavity is a reinforced-concrete structure forming a pool above the reactor when filled with borated water for refueling. The cavity is filled to a depth that limits the radiation at the surface of the water to 50 mR/hr during those brief periods when a fuel assembly is transferred to the upender and is at the closest approach to the surface of the water.

The reactor vessel flange is sealed to the bottom of the refueling cavity by a segmented seal ring that prevents leakage of refueling water from the cavity. This seal is fastened and closed after reactor cooldown, but before flooding the cavity for refueling operations. The segmented seal uses a passive sealing design which will preclude failure and leakage. During reactor operation, the seal is removed and normally stored outside the containment structure.

The cavity is large enough to provide storage space for the reactor upper internals, the control rod assembly drive shafts, miscellaneous refueling tools, and the lower internals.

The walls and floor of the refueling cavity are lined with 0.25-inch type 304 stainless steel.

9.12.3.2 Fuel Transfer Canals and Transfer Tubes

In each unit, a fuel transfer canal extends along one wall of the refueling cavity to the inside surface of the reactor containment. The canal is formed by two concrete shielding walls, which extend upward to the same elevation as the refueling cavity. The floor of the canal is at a lower elevation than the refueling cavity, to provide the greater depth required for the fuel transfer system upending device and the control rod assembly change fixture.

9.12.3.3 **Spent Fuel Pool**

The spent fuel pool is designed for the underwater storage of spent fuel assemblies and control rod assemblies after their removal from the reactor. It is designed to accommodate a total of approximately 1044 fuel assemblies. The nominal size of a full core is 157 assemblies.

The spent fuel pool is constructed of reinforced concrete. The entire interior of the pool is lined with 0.25-inch type 304 stainless steel.

High-density storage racks erected on the pool floor are provided to hold the spent fuel assemblies. Fuel assemblies are placed in vertical cells, grouped in parallel rows with a minimum center-to-center spacing of 14 inches. The racks ensure the necessary spacing between assemblies to prevent criticality even if the pool were inadvertently filled with unborated water. Control rod assemblies and other non-fuel inserts/components may be stored in the fuel assemblies. Storage rack design details are given in Appendix 9A.

Failed fuel rods removed when reconstituting fuel assemblies will be stored in a fuel rod canister which will be stored in one cell of the spent fuel storage racks. Each fuel rod canister is manufactured to the same exterior dimensions as a fuel assembly with a top nozzle similar to the fuel assembly. This will permit handling of the canister using normal fuel handling equipment and storage in the rack. Each canister contains tubes for the storage of individual fuel rods. The accidental dropping of a fully loaded fuel rod canister in the spent fuel pool is conservatively bounded by the Fuel Handling Accident in the Spent Fuel Pool described in Section 14.4.1.3, since that accident assumes all 204 rods of the highest power assembly are failed. The fuel rod canisters hold less than 204 rods.

Radiation monitors for the spent fuel pool area are provided as described in Section 11.3.4.

9.12.3.4 **New-Fuel Storage**

New fuel assemblies and control rod assemblies are stored in a separate area of the fuel building, where they are unloaded from trucks. This storage area is designed to hold 126 new fuel assemblies in vertical racks, and is used primarily for the storage of the one-third replacement core plus 10% for each of the two units. The new fuel assemblies are stored in racks in parallel rows having a minimum center-to-center distance of 21 inches.

Radiation monitoring for the new fuel storage area is discussed in Section 11.3.4.

9.12.4 Refueling Equipment

9.12.4.1 **Reactor Vessel Stud Tensioners**

Stud tensioners are used to make up the reactor vessel head closure joint. During this process all studs are stressed sufficiently to hold the closure heads seated and maintain leaktightness during operation.

The stud tensioner is a hydraulically operated device provided to permit preloading and unloading of the reactor vessel closure studs at cold shutdown conditions. Stud tensioners minimize the time required for the tensioning or unloading operations, minimize thread damage, and permit precision stud tensioning. Three tensioners are provided for each unit, and they are applied simultaneously to three studs 120 degrees apart. One hydraulic pumping unit operates the tensioners, which are hydraulically connected in parallel. The studs are tensioned to their operational load in two steps to prevent high stresses in the flange region and unequal loadings in the studs. Relief valves are provided on each tensioner to prevent overtensioning of the studs due to excessive pressure. In addition, micrometers are provided to measure the elongation of the studs after tensioning.

9.12.4.2 **Reactor Vessel Head Lifting Device**

The reactor vessel head lifting device consists of a welded and bolted structural steel frame with suitable rigging to enable the reactor containment crane operator to lift the bead and store it during refueling operations.

9.12.4.3 **Reactor Internals Lifting Device**

The reactor internals lifting device is a structural frame suspended from the reactor containment polar crane. One lifting device is provided for each unit. The frame is lowered onto the guide tube support plate of the internals and manually bolted to the support plate by three bolts, with long torque tubes extending up to an operating platform on the lifting device. Bushings on the frame engage guide studs in the vessel flange to provide close guidance during removal and replacement of the internals package.

9.12.4.4 **Manipulator Crane**

The manipulator crane is a rectilinear bridge and trolley crane with a vertical mast extending down into the reactor cavity water. A manipulator crane is provided for each unit. The bridge spans the reactor cavity and runs on rails set into the floor along the edge of the reactor cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core.

A long tube with a pneumatic gripper on the end is lowered down from the mast to grip the fuel assembly. The gripper tube is a telescopic device that is long enough that the upper end is still contained in the mast when the gripper end contacts the fuel. A winch mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. The fuel, while inside the mast tube, is transported to its new position.

All controls for the manipulator crane are mounted on a console located on the bridge. The bridge is positioned on a coordinate system laid out on one rail. The camera assembly monitors the bridge target and transmits that position to the closed circuit television screen. The operator visually observes the bridge scale assembly to line up the bridge to the appropriate location. The scale is read directly by the operator at the console. The drives for the bridge, trolley, and winch are variable speed, and include a separate inching control for each drive. Electrical interlocks and limit switches on the bridge and trolley drives protect the equipment. The bridge, trolley, and winch can also be operated manually using handwheels on the motor shafts.

The suspended weight on the gripper tool is monitored by an electrical load cell indicator mounted on the control console. A load in excess of approximately 2700 lb stops the winch drive from moving in the up direction. The gripper is interlocked through a weight-sensing device, and also a mechanical spring lock, so that it cannot be opened when supporting a fuel assembly.

In addition to the travel limit switches on the bridge and trolley drives, the following safety features are incorporated in the system:

1. Bridge, trolley, and winch drives are mutually interlocked to prevent simultaneous operation of any two drives.
2. Bridge and trolley main motor drive operation is prevented, except when the GRIPPER TUBE UP or GRIPPER UP DISENGAGED position switch is actuated.
3. A solenoid valve in the air line to the gripper is de-energized, except when less than or equal to 600 lb suspended weight is indicated by a force gauge. As backup protection for this interlock, the mechanical weigh-actuated lock in the gripper prevents operation of the gripper under load, even if air pressure is applied to the operating cylinder.
4. Hoist drive circuit in the up direction is opened when the “overload” switch is actuated.
5. Hoist drive circuit in the up direction is operable only when either the GRIPPER ENGAGED or GRIPPER DISENGAGED indicating switch on the gripper is actuated.
6. The limit switch in the electrical load cell indicator parallels the gripper-engaged switch. To complete the “hoist-up” circuit, either the gripper must be engaged or the load cell indicator must read less than 1200 lb. This will prevent inadvertently raising a disengaged fuel assembly that is for some reason hung up on the gripper.
7. Bridge and trolley drives are interlocked in the direction of the transfer system so that the bridge is prevented from traveling beyond the core area unless the trolley is aligned with the refueling canal centerline. The trolley drive is locked out when the bridge is moved beyond the edge of the core. The trolley drive is not locked out; it is enabled in the refueling canal area.

Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing due to the design-basis earthquake. The manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper under the design-basis earthquake. The manipulator crane is parked to one side of the reactor and secured when not in use. The manipulator crane is designed as a Class I component (Section 15.2.1).

9.12.4.5 **Motor-Driven Platform and Hoist**

The movable platform with hoists in the fuel building is a wheel-mounted, motor-driven platform with overhead trusses supporting electric monorail hoists for lifting new fuel assemblies, spent fuel assemblies, and fuel assembly inserts. The platform spans the spent fuel pool and may be maneuvered over any part of the fuel building area necessary for fuel handling operations. The hoist travel and the length of the long fuel-handling tool are designed to limit the maximum lift of a spent fuel assembly to ensure an adequate water shield above the fuel. The movable platform is designed as a Class I component (Section 15.2.1), and is parked to one side of the spent fuel racks and secured when not in use. Suitable restraints are provided between the bridge and the rails to prevent derailing during the design-basis earthquake.

9.12.4.6 **Fuel Handling Tools**

A variety of fuel assembly and component handling tools are used during the core alteration process in the containment and the fuel building, during the loading or unloading of storage casks, or during the loading of shipping casks.

In the containment, movement will be between core locations and the fuel upender. Use of the rod cluster control change fixture is prohibited by procedure because of concerns related to potential loss of refueling cavity level. Fuel assembly movements in the containment are done with the manipulator crane and gripper tube. The locations of these components are shown on Reference Drawings 1 and 2.

In the fuel building, movement during refuelings will be between the fuel upender and/or fuel storage locations and/or the fuel elevator. Fuel assembly movements for spent fuel casks will be between fuel storage locations and the cask. Fuel and component movements in the fuel building are done with the following tools:

1. Spent fuel assembly handling tool
2. Thimble plug handling tool
3. Hand-operated burnable poison rod assembly handling tool
4. Rod cluster control assembly handling tool

9.12.4.7 **Reactor Irradiation Sample and Sample Handling Tool**

As part of the reactor vessel irradiation surveillance program, reactor irradiation sample assemblies are removed from the vessel at approximately 10-year intervals for examination and testing. The sample assemblies are approximately 10 feet long, 1.25 inches in cross-section, and weigh approximately 25 lb. To remove the sample, a sample basket is transferred from the fuel building to the containment using the fuel transfer system. The sample assembly is removed from the vessel using the sample handling tool, and placed in the sample basket. The sample basket is then returned to the fuel building for storage in the spent fuel racks. The sample is shipped off-site for analysis within a short period of time.

9.12.4.8 **Core Mapping Equipment**

Following core alterations, the proper location of fuel assemblies is verified. An underwater television camera and videotape equipment may be used. The camera is suspended above the fuel assemblies during the mapping process.

9.12.4.9 **Fuel Transfer System**

The fuel transfer system for each unit, shown in Reference Drawing 2, is an underwater conveyor car and track system that extends from the refueling canal through the transfer tube and into the spent fuel pool. The conveyor car receives a fuel assembly in the vertical position from the manipulator crane, after which the fuel assembly is tilted to a horizontal position and passed through the transfer tube to the spent fuel pool. Inside the spent fuel pool, it is tilted to a vertical position in preparation for placement in the storage racks. Cranes over the spent fuel pool are used for moving new fuel assemblies, spent fuel assemblies, and fuel assembly inserts (Reference Drawing 3).

During reactor power operation, the conveyor car is stored in the containment and the transfer tube cover is in place on the transfer tube to seal the reactor containment penetration.

9.12.4.10 **Fuel Elevator**

The fuel elevator lowers new fuel assemblies from the top to the bottom of the spent fuel pool so that the new fuel-handling tool and the hook and cable of the traveling platform hoist do not become contaminated by immersion in the pool water. Removal of the fuel assembly from the elevator at the bottom of the pool is accomplished with the long fuel-handling tool, which also is used for transferring spent fuel. To ensure that the spent fuel is not raised above the water level in the spent fuel pool, a key lock switch has been placed in series with the elevator up-button. The fuel elevator is a Class I component.

9.12.4.11 **Control Rod Assembly Changing Fixture**

A fixture is mounted on a wall of each reactor cavity for removing control rod assemblies from spent fuel assemblies and inserting them into other fuel assemblies. The fixture consists of two main components: a guide tube mounted to the wall for containing and guiding the control rod assembly, and a wheel-mounted carriage for holding the fuel assemblies and positioning fuel assemblies under the guide tube. The guide tube contains a pneumatic gripper on a winch that grips the control rod assembly and lifts it out of the fuel assembly. By positioning the carriage, a new fuel assembly is brought under the guide tube and the gripper lowers the control rod assembly into place. The manipulator crane loads and removes the fuel assemblies into and out of the carriage. The above noted equipment is available. However, it is not used at this time. The removal and reinsertion of the control rods into the fuel assemblies are performed in the spent fuel pool. A portable change tool is utilized to relocate the control rods in the spent fuel pool.

9.12.4.12 **Refueling Water Storage Tank**

The refueling water storage tank of each unit (Section 6.2.2.1) provides the water for filling the reactor cavity and for certain safeguards systems.

9.12.4.13 **Fuel Cask Trolley**

The crane for handling the spent fuel cask is a trolley of 125-ton capacity running on fixed rails. The rails span the east end of the fuel pool in an area where no spent fuel storage racks are installed. The rails pass over the decontamination building and then over the roadway. The fuel cask trolley is designed as a Seismic Category I component.

Restraints are provided to prevent displacement of the trolley from the rails.

A 10-ton auxiliary hoist is installed on the South side of the crane. A 1-ton electric chain hoist is installed on the South side and top of the crane to permit fuel-handling tools to be removed from the spent fuel pool for the purposes of inspection or maintenance.

The spent fuel cask and other heavy objects cannot be moved over stored fuel. The 125-ton fuel building crane is a trolley that moves only in a north-south direction over an area at one end of the fuel pool. Spent fuelracks are excluded from this area.

Originally there was a built-up pad of energy-absorbing material over the floor of the fuel pool in the cask loading area. This has been replaced with a pad requiring no maintenance. The new cask pad utilizes large pipes that will plastically deform under a heavy-impact load and thus prevent pool damage. The pipes are open-ended to allow for free movement of water. All materials are stainless steel for corrosion resistance. The cask pad is designed to prevent significant damage to the spent fuel pool from a dropped shipping cask and is designed to protect the pool against spent fuel casks of various sizes. The cask pad also provides a support platform for the shipping cask during loading of spent fuel.

The new cask pad has been installed in the recessed area provided in the spent fuel pool and located in the northeast corner of the pool. A smaller pad has been installed on the pool floor just south of the cask loading area. The smaller pad extends the length of the protected area to prevent unacceptable damage to the fuel pool bottom from the postulated accident of the cask tipping after hitting the bottom. The design of the smaller pad is similar to the larger cask pad.

An analysis has been performed for dropping of a spent fuel shipping cask into the spent fuel pool. The analysis addressed the consequences of a cask drop to adjacent spent fuel and to the pool structure. See Section 9B.1.5.

If the stainless steel fuel pool liner plate is damaged by a cask-drop accident, water could leak into the liner test channels. The test channels are connected to a 0.5-inch pipe, which is buried under the fuel pool and leads to the fuel building sump. This pipe is plugged at the entrance to the sump to prevent any water from escaping from the fuel pool. Should the plug fail or be inadvertently left off, and if the impact damaged the liner at a test channel, water would leak out of the fuel pool at a rate not exceeding 5 gpm.

The normal makeup capability from the primary-grade water system is 200 gpm. An emergency source of makeup is available from the fire main at a rate of up to 2000 gpm.

9.12.4.14 **Polar Crane**

The overhead crane in the containment is of the polar configuration and is supported on the circular crane wall. The crane has two main hooks with a capacity of 140 tons each, with a maximum hook elevation of approximately 52 feet above the operating floor. The polar crane has access to the entire area within the crane wall. The crane is designed as a Class I component. No parts of the crane can be dislodged during an earthquake.

Restraints are provided between the trolley and bridge and between the bridge and rails to prevent derailing during a design-basis earthquake.

9.12.5 Refueling Procedure

9.12.5.1 **Design Bases**

The refueling operation follows a detailed operating procedure that is established to provide a safe, efficient refueling operation. The movement of heavy loads near spent fuel is discussed in Appendix 9B. The following significant points are ensured by the refueling procedure:

1. The refueling water contains approximately 2500 ppm boron. The boron concentration, together with the control rods, is sufficient to keep the core approximately 5% delta k/k subcritical during the refueling operations. The boron concentration is sufficient to maintain the core shutdown if all of the control rods were removed from the core.
2. The water level in the reactor cavity is high enough to keep the radiation levels within acceptable limits when the fuel assemblies are being removed from the core. This water also provides adequate cooling for the fuel assemblies during transfer operations.
3. Fuel-handling operations and equipment are designed so that the possibility of fuel mishandling or damage is minimized.

9.12.5.2 **Preparation Sequence**

1. For Unit 1, the reactor is shut down and cooled to ambient conditions.
2. For Unit 1, the control rod assembly drive mechanism missile shield is removed and stored in the containment.

For Unit 2, CRDM cables, RPI cables, instrument leads, and RV head vent valve cables are disconnected and the CRDM cable bridge and RPI cable bridge are raised.

3. For Unit 1, control rod drive assembly mechanism cables and cooling air ducts are disconnected from the mechanisms and stored in the containment.

   For Unit 2, the RV head lift tripod is installed on the Head Assembly Upgrade Package and cooling air ducts are disconnected from the plenum and stored in the containment.

4. Reactor vessel head insulation and instrument leads are removed.

5. The reactor vessel cavity seal ring is placed in position and installed.

6. The fuel transfer tube cover is removed.

7. The reactor vessel head nuts are loosened with the hydraulic tensioners.

8. The reactor vessel head studs are removed for testing and storage.

9. Checkout of the fuel transfer device and manipulator crane is completed.

10. Guide studs are installed in three holes, and the remainder of the stud holes are plugged.

11. Final preparation of underwater lights and tools is made.

12. The reactor vessel water-level is raised to the level of the vessel flange. The water is transferred from the refueling water storage tank through the reactor vessel.

13. The reactor vessel head is unseated and raised with the reactor containment polar crane and held for inspections of the head lift rig.

14. The source range instrumentation is monitored to verify that the RCC's are not being removed with the closure head.

15. When the reactor vessel head is lifted between 8 and 10 feet, the head lift is stopped and a visual inspection is made to verify that the RCC element drive shafts are free from mechanism housing and were not raised with the closure head.

16. The reactor vessel head is removed to its storage pedestal on the bottom floor of the reactor containment.

17. As the vessel head is being stored, the cavity is immediately being filled to minimize radiation exposure. The refueling cavity is filled 1 ft. 6 in. to check cavity seal integrity. Then the cavity is filled to approximately 16 feet.

18. Before removing the reactor vessel upper internals, all the control rod assembly drive shafts are unlatched and verified.

19. The reactor vessel internals lifting rig is lowered into position by the containment crane and latched to the support plate.

20. The cavity is filled to between the 26 and 27 feet level in coordination with lifting the internals.

21. The reactor vessel upper internals package is lifted out of the vessel and placed in the underwater storage stand on the floor of the refueling cavity.

22. Removal, insertion, and shifting of fuel assemblies proceed in accordance with the refueling sequence (Section 9.12.5.3).

9.12.5.3 **Refueling Sequence**

The refueling sequence is started with the manipulator crane. The sequence for fuel assemblies is as follows:

1. Spent fuel is removed from the core and placed into the fuel transfer system for removal to the spent fuel pool.

2. New fuel and partially spent fuel assemblies are brought in from the spent fuel pool through the fuel transfer system and loaded in the core.

3. The subcriticality of the reactor will be determined after a minimum of 8 fuel assemblies have been added to the reactor core. Thereafter, whenever a fuel assembly is added to the reactor core, either the source range counts is to be monitored for a doubling, or a reciprocal curve of source neutron multiplication is to be plotted to verify the subcriticality of the core at periodic intervals.

9.12.5.4 **Reassembly Sequence**

1. The fuel transfer system conveyor car is parked and the fuel transfer tube isolation valve closed.

2. The reactor vessel internals package is picked up by the reactor containment polar crane and replaced in the reactor vessel. As the upper internals are lowered into the reactor vessel, the refueling cavity water level is lowered to an intermediate level. The reactor vessel internals' lifting rig is removed to storage.

3. The control rod assembly drive shafts are relatched to the control rods.

4. The refueling cavity water-level is lowered, and water is pumped from the refueling cavity into the refueling water storage tank.

5. When the water in the refueling cavity is slightly below the vessel flange level, the pump down is secured.

6. The reactor vessel head is picked up by the reactor containment polar crane and positioned over the reactor vessel.

7. The reactor vessel head is slowly lowered to engage the guide studs. Lowering the head is stopped when the guide studs penetrate the bolt holes.

8. Lower inspectors into the cavity and visually inspect for drive shaft to thermal sleeve alignment. Slowly lower the reactor vessel head until all drive shafts are in their thermal sleeve guide funnels.
9. The reactor vessel head is seated.
10. The guide studs are removed to their storage rack. The stud hole plugs are removed.
11. The fuel transfer tube cover is replaced.
12. The reactor vessel cavity seal may be removed anytime following replacement of the transfer tube cover.
13. The head studs are replaced and retensioned.
14. Vessel head insulation is replaced.
15. For Unit 1, electrical leads and cooling air ducts are reconnected to the control rod assembly drive mechanisms.

    For Unit 2, the CRDM cable bridge and RPI cable bridge are lowered into place and electrical leads and air cooling ducts are reconnected. The head lifting rig tripod is removed.
16. For Unit 1, the control rod assembly drive mechanism missile shield is picked up with the reactor containment crane and replaced.
17. - An inservice leak test is performed on the reactor coolant system.
    - Control rod assembly drive operation is checked.
    - Preoperational start-up tests are performed.

NOTE: The activities listed under item #17 are not necessarily performed in that order.

9.12.6 Fuel Handling System Design Evaluation

Underwater transfer of spent fuel provides essential simplicity and safety in handling operations. Water is an effective, economic, and transparent radiation shield, and a reliable cooling medium for removal of decay heat.

Basic provisions to ensure the safety of refueling operations include the following:

1. Gamma radiation levels in the containment and fuel storage areas are continuously monitored. These monitors provide an audible alarm at the initiating detector and in the control room, indicating an unsafe condition. Continuous monitoring of reactor neutron flux provides immediate indication and alarm in the control room of an abnormal core flux level.
2. Violation of containment integrity is not permitted when the reactor vessel head is removed unless the shutdown margin is maintained greater than 5% delta k/k.
3. After a minimum of 8 fuel assemblies have been added to the reactor core, the reciprocal curve of source neutron multiplication is monitored to verify the subcriticality of the core.

4. The operation is adequately supervised and planned.
5. During REFUELING OPERATIONS, the personnel airlock, the equipment hatch, and other containment penetrations must be capable of being closed. ‘Capable of being closed’ means the openings are able to be closed; they do not have to be sealed or meet the leakage criteria of TS 4.4.

9.12.6.1 **Incident Control**

Direct communication between the control room and the reactor cavity manipulator crane will be established whenever changes in core geometry or conditions are taking place. This provision allows the control room operator to inform the manipulator crane operator of any impending unsafe condition detected by control room indicators during fuel movement.

During refueling operations personnel will be assigned tasks to ensure that open containment penetrations are closed following a fuel handling accident in containment. There should be an individual, who, in addition to their normal duties, is also responsible for making sure one of the personnel airlock doors is closed when the last person is out of containment. The individual should not be outside the protected area but neither does the person have to remain near the airlock. Closure of the equipment access hatch is the duty of a team trained for that task and controlled in accordance with station procedures. Equipment hatch closure will be accomplished as allowed by containment dose rates, which may require containment entry after the personnel airlock has been closed. A part of the closure responsibilities is the removal of objects that penetrate the equipment access hatch and the personnel airlock and would hinder closure. These objects include, but are not limited to guards over the door seals to protect the seals from being damaged, tracks that allow movement of heavy equipment into and out of containment, temporary power lines, etc. These objects are not considered blocking closure as long as they are removable in a reasonable time.

9.12.6.2 **Malfunction Analysis**

An analysis of the consequences of a fuel-handling incident is presented in Section 14.4.1.

9.12.7 Minimum Operating Conditions

Minimum operating conditions for the fuel handling system are contained in the Technical Specifications.

9.12.8 Tests and Inspections

Prior to initial fueling, preoperational checkouts of the fuel handling equipment were performed to ensure proper performance of the fuel handling equipment, and to familiarize operating personnel with operation of the equipment. A dummy fuel assembly was used.

Electrical lighting receptacles are mounted around the spent fuel pool. These receptacles provide additional lighting during fuel pool inspections. All of the receptacles have weather-proof covers.

Upon completion of initial core loading and installation of the reactor vessel head, certain mechanical and electrical tests were performed prior to initial criticality. The electrical wiring for the control rod assembly drive circuits, the control rod assembly position indicators, the reactor trip circuits, the incore thermocouples, and the reactor vessel head water temperature thermocouples were tested at the time of installation. The tests were repeated on these electrical items before initial operation.

Prior to subsequent refueling operations, the equipment is inspected for operating condition, and certain components, such as the fuel transfer car and manipulator crane, are operated to ensure reliable performance before moving irradiated fuel. Pre-refueling checks are part of a continuing program.

9.12.9 Spent Fuel Storage at the Independent Spent Fuel Storage Installation (ISFSI)

As described in Section 9.12.3.3 and Appendix 9A, spent fuel assemblies are stored in the Surry spent fuel pool to allow post-irradiation cooling of the spent fuel. With construction of the Surry ISFSI, dry storage provides additional capacity for on-site interim storage of spent fuel. The Surry ISFSI is licensed for dry storage systems under 10 CFR 72 (License No. SNM-2501). Surry has also selected the NUHOMS-HD spent fuel storage system under the 10 CFR 72 general license issued to Transnuclear, Inc. (Certificate of Compliance #1030)

Pads 1 and 2 at the ISFSI are designed for vertical, metal dry storage systems, and the NRC, as part of the site license, has approved five storage systems. The design and operation of the ISFSI and the approved storage systems are described in the ISFSI Safety Analysis Report (SAR) (Reference 1) and the storage system Topical Safety Analysis Reports (TSARs) referenced in the SAR. Pad 3 at the ISFSI is designed for storage using the NUHOMS-HD system. The design and operation of this system are described in the NUHOMS FSAR (Reference 2). Pad 4 at the ISFSI is designed for storage using the NUHOMS EOS system. The design and operation of this system are described in the NUHOMS EOS UFSAR (Reference 3).

Handling of dry storage systems in the Surry Station for loading or unloading must meet the requirements of Appendix 9B.

9.12 REFERENCES

1. *Dry Cask Independent Spent Fuel Storage Installation (ISFSI) Safety Analysis Report.*
2. *Final Safety Analysis Report, Horizontal Modular Storage System for Irradiated Nuclear Fuel (NUHOMS).*
3. SU-MANUAL-000-EOS-SPS-FSAR Rev. 3, *NUHOMS EOS System Updated Final Safety Analysis Report*.

9.12 REFERENCE DRAWINGS

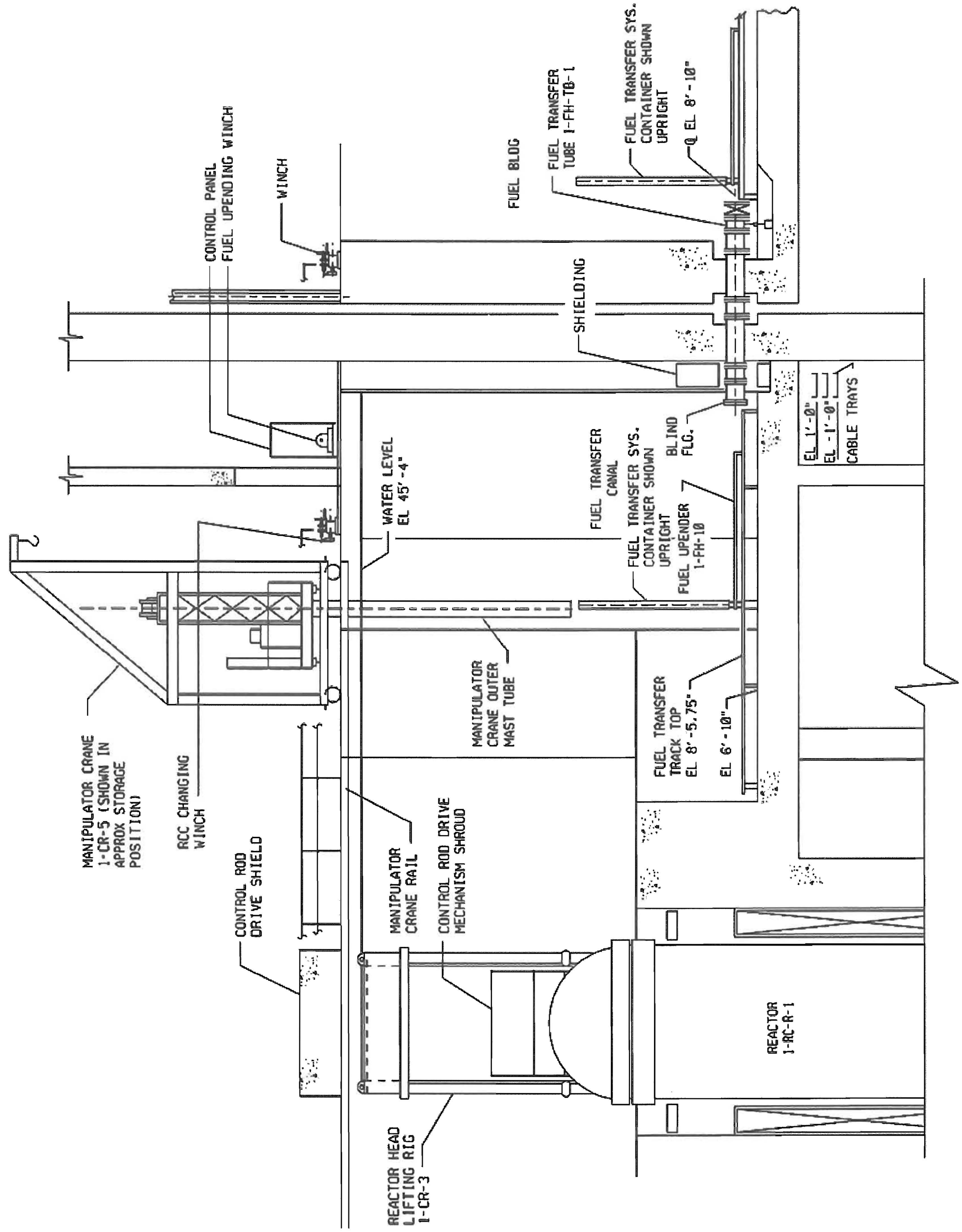
The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-1B	Machine Location: Reactor Containment, Elevation 18'- 4"
2.	11448-FM-1E	Machine Location: Reactor Containment; Sections “A-A”, “E-E”, & “Z-Z”
3.	11448-FM-9B	Arrangement: Fuel Building, Sheet 2, Unit 1

Table 9.12-1
FUEL-HANDLING DATA

New fuel storage area (common to both units)	
Core storage capacity	2/3 +20%
Equivalent fuel assemblies	126
Center-to-center spacing of assemblies	21 in.
Maximum k_{eff} possible with unborated water	0.98
Spent fuel storage pool (common to both units)	
Core storage capacity	6-1/3 +30%
Equivalent fuel assemblies	1044
Number of space accommodations for spent fuel casks	1
Center-to-center spacing of assemblies	14 in.
Maximum k_{eff} possible with unborated water	0.95
Miscellaneous details	
Width of refueling canal	3 ft
Wall thickness for spent fuel storage pool	3 to 6 ft
Weight of fuel assembly with control rod assembly (dry)	≈1635 lb
Capacity of each refueling water storage tank	375,000 gal
Minimum contents of each refueling water storage tank for safety injection and spray system operability	350,000 gal
Quantity of water required for refueling	220,000 gal

Figure 9.12-1
FUEL TRANSFER SYSTEM



Intentionally Blank

9.13 AUXILIARY VENTILATION SYSTEMS

9.13.1 General Description

The auxiliary ventilation system diagrams are shown on Reference Drawing 5. These include the ventilation and heating systems for the auxiliary building, fuel building, decontamination building, and safeguards areas adjacent to the reactor containments. The cable vault cooling is shown on Reference Drawings 1 and 3. The control and relay room area cooling is shown on Reference Drawing 3. The auxiliary building, fuel building, decontamination building, control room, and ventilation vents are shared by the two units. Individual cable vaults and safeguards areas, and relay rooms, are provided for each unit. The control room and relay rooms for both units are in the service building.

The auxiliary building is a four-level compartmented structure containing the auxiliary nuclear equipment for both units. Equipment handling radioactive fluids is located on the lower three levels, isolated and shielded as required. The upper level is a ventilation equipment room.

Waste gases with a relatively high potential for radioactivity are discharged through filters or the gaseous waste disposal system to the process vent (Section 11.2.5.1). The ventilation exhausts from some primary plant areas are subject to comparatively slight radioactive contamination from such limited sources as pump gland or pipe weepage. The following features are incorporated in these exhaust systems to protect the environment from this relatively remote contamination possibility:

1. For all areas except the auxiliary building central area, two exhaust fans, which provide 100% of the required capacity, are installed in parallel, with an automatic back-flow damper on each fan. One fan will provide approximately 60%-capacity exhaust in the event the other fan fails, or a step flow reduction capacity is desired in the event of radioactive contamination. The auxiliary building central area has two parallel 100%-capacity exhaust fans, also equipped with automatic back-flow dampers.
2. Three iodine filter assemblies, two safety-related and one non-safety-related, are provided. Each filter bank consists of roughing, high efficiency particulate air (HEPA), and charcoal filters. Perforated plate air distribution and straightening sub-plenums are installed in the inlet and outlet plenums of the two safety-related filter housings to provide uniform air flow through the filter housings. The parallel arrangement provides an effective standby filter if one assembly becomes saturated.
3. Two safety-related, high-head fans, sized to draw 36,000 cfm each primarily from emergency core cooling system (ECCS) equipment areas through the safety-related filters, are provided. One non-safety-related, high-head fan, sized to draw the design flow rate of the auxiliary building general area exhaust system through the non-safety-related filter system, is also provided. The capacity of each safety-related high-head fan is 100%. When operating individually, the capacity of each safety-related fan is automatically controlled by electrohydraulically operated inlet valves to draw the design flow rates. When both are

operating, the system configuration limits the flow through each fan to less than 32,400 cfm, even though both inlet valves are full open. In this alignment, the total system flow is greater than the 36,000 cfm required for cooling purposes. The 36,000-cfm ±10% capacity of each filter train equals the maximum design exhaust flow rate from ECCS equipment areas. Each fan has redundant 480V power supplies.

4. Exhaust bypass arrangements allow for selective filtration of any exhaust system. Parallel dampers for each of the safeguards and charging pump exhaust systems provide redundant flow paths to the filters following a loss-of-coolant accident (LOCA). Other exhaust systems have dampers in series to provide redundant closure following a LOCA. All bypass and filter dampers are remote manually operated from the control room as required. In addition, the affected safeguards area and the charging pump ventilation exhaust systems are automatically aligned upon a safety injection signal to ensure flow is diverted to safety related charcoal filters such that airborne radioactivity from the safeguards area and from the exhaust stream from the charging pump cubicles will be removed. The automatic realignment feature for the ventilation system may be defeated as discussed in Section 9.13.4.1. This condition is not expected however, since defeating the automatic realignment is no longer credited in the fuel handling accident analysis, and procedural controls have been established to eliminate operating with automatic alignment defeated. During refueling, the fuel building exhaust may be passed through charcoal filters to ensure radioactivity removal in case of airborne contamination from any source. However, there is no requirement to filter the exhaust since filtration is not credited in the fuel handling accident analysis.

5. Exhaust to the atmosphere is through a common, continuously monitored ventilation vent (ventilation vent no. 2) located on the roof of the auxiliary building. The vent discharges upward with a velocity in excess of 4000 fpm. For details of monitoring equipment and diversion of ventilation control, see Section 11.3.3. A second ventilation vent (ventilation vent no. 1) is located on top of the service building. The gases originating from labs and counting facilities may contain radioactive gases and are monitored just prior to entering this vent stack. The other potentially contaminated inputs entering this vent are the condenser air ejector exhausts. These vent streams are separately monitored.

HVAC systems which are designed primarily to be used only for post accident are in the Technical Support Center (TSC). Filtration is provided in the post accident modes consistent with the anticipated hazards.

The normal HVAC systems which have neither airborne contamination control functions or post accident mitigation functions are not considered available following a loss of offsite power. The system designs range from once through to full recirculation depending on equipment and personnel needs. The design bases are similar to the post accident or airborne contamination systems described in Section 9.13.2.

9.13.2 Design Bases

Outside ambient conditions used for design purposes are 93°F summer dry bulb, 78°F summer wet bulb, 73°F summer dewpoint, 10°F winter dry bulb, 58°F all-year ground temperature, and 15-mph all-year wind velocity.

Normal, full power ventilation is based on limiting the temperature in various locations as follows:

Building	Temperature
Fuel building (with a fuel pool water temperature of 140°F)	105°F maximum, 75°F minimum and 79°F dewpoint
Decontamination building	120°F maximum, 50°F minimum for storage and tank spaces
	105°F maximum, 65°F minimum for work spaces
Safeguards building	120°F maximum in pump cubicles, 50°F minimum
Auxiliary building	120°F maximum, 50°F minimum in nuclear auxiliary equipment cubicles
	105°F maximum, 50°F minimum for the balance of the building and ventilation equipment room
Reactor containment	60°F minimum with purging system in operation
Laundry facility	78°F maximum to 68°F minimum
	80% RH to 10% RH

The use of the high-head fans when the exhaust systems are diverted through the filters ensure that the design space temperatures and purging rates are maintained.

Ventilation for nuclear auxiliary systems is designed on a once-through basis. Supply air is introduced to areas least likely to be contaminated, and then exhausted directly from those with the greatest contamination potential.

The safety-related auxiliary ventilation exhaust filter system is designed to mitigate the release of iodine following a Chapter 14 design basis accident to ensure that both the offsite doses and, in conjunction with the Control Room Air Filtration System, the Control Room doses are maintained within the limits of 10 CFR 50.67. The design of the system provides for (1) uniform air distribution across the prefilter bank within 20% of average velocity, (2) a HEPA filter with 99.5% particulate removal efficiency, (3) charcoal adsorber banks which have less than 1% halogen leakage when tested, and (4) charcoal adsorbers which have a methyl iodide removal efficiency of ≥ 86% when tested in accordance with Technical Specification Surveillance Requirement 4.12.B.7.

The TSC charcoal filter meets the qualifications for a safety-related filter and is tested on the safety-related frequencies.

The non-safety-related filter used to filter frequently contaminated auxiliary building exhaust air has a 99% particulate removal efficiency and a 1% halogen leakage. The air is uniformly distributed within ±20% of the average flow across the face of the filter.

The control room air conditioning is designed to maintain 75±10°F dry bulb during either normal or emergency conditions for personnel comfort except during a turbine building high energy line break (HELB). The emergency switchgear and relay rooms are designed for 80°F dry bulb during normal conditions, and 87°F dry bulb during emergency operations except during a turbine building HELB. Refer to Section 7.7 for equipment qualification information.

The control and relay room area exhaust and replenishment supply ventilation is provided by external systems for normal operations. In an emergency, the control and relay room area is sealed with weather-stripped doors and tight external duct closures. The air conditioning systems will continue to operate normally. Emergency supply fans can be manually aligned to take suction from the turbine building through roughing, particulate, and iodine filters to supply filtered breathing air to the control room indefinitely.

Air-conditioning and associated auxiliary equipment required to operate during emergency conditions are powered from emergency buses.

The ventilation exhaust from the safeguards areas to ventilation vent no. 2, and ventilation vent no. 2, meet Class I design criteria (Section 15.2). This includes the entire ECCS collection and filtration system and the Units 1 and 2 purge exhaust ducts between the containment purge exhaust isolation valves and the safety-related filters. Air-conditioning and emergency ventilation equipment for the control and relay room area also meet Class I design criteria.

Ventilation system arrangements are shown on Reference Drawings 1 through 4.

9.13.3 System Descriptions

9.13.3.1 Auxiliary Building Ventilation

The auxiliary building is supplied with air by two 31,000-cfm air-handling units. The systems have automatic roll filters for continuous cleaning, and steam coils for winter heating. Under normal operating conditions, three exhaust fans are used: one fan for the central spaces, and two fans for the general area which includes the remainder of the potentially contaminated spaces in the auxiliary building. Airflow from the central spaces is nominally 24,000 cfm and is based on two charging pumps operating. Airflow from the general area is approximately 48,000 cfm. The exhausts with radioactive contamination potential always discharge through ventilation vent no. 2. These exhausts can be diverted remotely through the common filter subsystems from the control room, as described in Section 9.13.1. Particulate filters are installed in the exhaust branches from the auxiliary building sample cooler spaces for continuous filtration.

The exhaust ducts from the cubicles of the volume control tanks, containment vacuum pumps, sampling coolers and sinks, process vent blower, gaseous waste disposal system, and recombiner are connected to the general area exhaust system. These cubicle exhausts represent non-safety-related cubicle exhausts and are therefore combined with the general area exhaust system. This exhaust is normally exhausted to the atmosphere via the radiologically monitored ventilation vent no. 2, but can be routed through the non-safety-related filter.

The exhaust duct of each charging pump cubicle has a two-position damper installed to open and exhaust air when the pump is operating and to close when the pump stops. The charging pump exhaust system flow rate is nominally 22,000 cfm following a LOCA. This is the major contribution to the design flow rate capability of the safety-related filter system.

Spaces subject to radioactive contamination have exhaust intakes located as far removed from the space access as feasible. The resulting negative pressure draws the makeup air in through the access and sweeps the space with supply air so that airborne contamination from equipment leakage will be drawn inward to the exhaust.

9.13.3.2 **Fuel Building Ventilation**

The ventilation provides heating to 90°F to inhibit the buildup of condensation, high-efficiency filtration to reduce the possibility of clouding the spent-fuel pool, and an excess exhaust flow to maintain a negative pressure in the building for inward leakage. Two supply fans and dual exhaust fans are provided to permit step capacity reduction in case of airborne contamination and to reduce steam requirements for winter heating.

Two supply fans are provided, one of 29,000-cfm capacity serving the spent-fuel pit, and one of 5000-cfm capacity for the remote equipment space at Elevation 6 ft. 10 in. Both take suction from a common plenum fitted with a combination roll and high-efficiency filter (minimum 90% NBS atmospheric dust) and steam coils for space heating. Heating control, both summer and winter, is as follows:

1. 75°F minimum summer and winter inside temperature, 105°F maximum temperature.
2. Vary the temperature difference between inside and outside from 30°F delta T at 45°F outside to 15°F delta T at 75°F outside.
3. Terminate heating at 90°F inside temperature.

Dual exhaust fans of 17,500-cfm capacity each discharge through ventilation vent no. 2. The larger exhaust flow rate (compared to supply flow rate) is to ensure that only inward leakage occurs. This exhaust may be diverted through the common iodine filter bank during refueling. The exhaust duct from the waste gas compressor cubicle of the fuel building was disconnected from the decontamination building exhaust header and connected to the fuel building exhaust header. Dampers are installed in series to provide redundant closure following a LOCA.

9.13.3.3 **Decontamination Building Ventilation**

The decontamination building is ventilated at approximately 15 air changes per hour, and arranged to maintain a negative pressure for inward leakage.

The supply system incorporates a continuous roll filter, steam coils for space heating, and supply fan. During normal operation, the supply fan is only operated if both exhaust fans are operated. Following a LOCA, the supply fan may continue to operate.

Dual exhaust fans discharge through ventilation vent no. 2 with a remote manual bypass arrangement to discharge through a filter bank, if needed. Dampers are installed in series to provide redundant closure following a LOCA.

9.13.3.4 **Safeguards Area Ventilation**

The safeguards areas are outside of, and adjacent to, each reactor containment structure. They contain the recirculation spray pumps, low-head safety injection pumps, refueling water recirculation pumps, containment spray pumps, and motor control center. These areas have a contamination potential and are exhausted by 6000-cfm-capacity dual fans located in the auxiliary building, which discharge to ventilation vent no. 2. An automatic capability is provided for the recirculation spray pumps, low-head safety injection pumps, and valve operating space areas for particulate and iodine filtration on a safety injection signal. Parallel dampers are installed to provide redundant flow paths to the filters following a LOCA.

Heated supply air is provided for all spaces. The supply system is fitted with continuous roll filters and steam heating coils for cold-weather space heating. The ventilation system is operated with a larger exhaust flow rate than supply flow rate to ensure inward leakage. This is accomplished by not operating the 16,000 cfm supply fan.

The Main Steam Valve House (MSVH) is adjacent to the safeguards area and houses the auxiliary feedwater pumps. The MSVH is not considered a potentially contaminated area and, therefore, this area is exhausted directly to atmosphere. Ventilation is provided by a wall-mounted exhaust fan and by openings in the wall at ground level and in the roof. The space is not heated since the main steam lines within the structure provide sufficient heating.

9.13.3.5 **Service Building Ventilation**

The ventilation for service building spaces subject to possible radioactive contamination is described below.

The hot laboratory, count room, and Health Physics lab are exhausted by two 2325-cfm fans in parallel. The exhaust is continuously drawn through roughing and particulate filters and discharged through the monitored ventilation vent no. 1. The controlled corridors, decontamination area, and one laboratory fume hood are exhausted by a 4000 cfm fan through roughing and particulate filters. Discharge is to the monitored ventilation vent no. 1.

Ventilation exhausts for the remainder of the service, turbine, and yard buildings are discharged directly to the atmosphere.

9.13.3.6 Main Control Room and Emergency Switchgear and Relay Room Ventilation

The air-conditioning equipment for the main control room (MCR) and emergency switchgear and relay room area is located within tornado-protected and missile-protected structures to ensure cooling during both normal and accident conditions.

Each MCR and emergency switchgear and relay room area is air conditioned by one of two air-handling units installed within the space served. The eight AHUs are arranged in two separate chilled water loops (4 AHUs on each loop), and either one or both chilled water loops are operated, as necessary, to maintain space temperatures. With only one loop in operation, one chiller provides chilled water to all operating AHUs. With both loops in service, two chillers provide chilled water separately to each loop, but only two AHUs are operating on each loop. Condensing cooling water is provided by service water lines described in Section 9.9.

Three chillers are located in Mechanical Equipment Room No. 3 (MER-3), and two chillers are located in Mechanical Equipment Room No. 5 (MER-5). This arrangement prevents full loss of cooling in the event of a fire in either MER-3 or MER-5. Three of the five chillers are powered from either of two buses, enabling maximum system flexibility in aligning the chillers as required. Additional equipment includes control panels and isolation switches for affected air handling units and cables routed to provide the required separation. The additional equipment is seismically and environmentally qualified, as applicable. Control of the air conditioning system is remote manual from the control room. An Appendix R power feed is available to power one chiller in MER-5 from MCC 1A2-3 (which can be supplied from the AAC) in the event of an Appendix R fire in Unit 2 Emergency Switchgear Room.

The MCR and emergency switchgear and relay rooms supply and exhaust air is provided by other systems. These systems are balanced to provide a positive pressure within the MCR and emergency switchgear and relay rooms with the boundary doors closed. Tight, redundant, Seismic Category I isolation dampers (remote manually or automatically operated closures in the ducts) and weather-stripped doors permit isolation of the control room envelope. Emergency ventilation is provided for each space. Emergency ventilation takes suction from the turbine building through roughing particulate filters, high efficiency particulate air (HEPA) filters, and charcoal adsorbers to remove airborne radioactivity. Following a design basis accident, the emergency ventilation system is assumed to operate within 1 hour of control room envelope isolation. The emergency ventilation system will indefinitely provide a supply of filtered breathing air. Control of the emergency ventilation system is remote manual from the control room. Emergency power is supplied for emergency ventilation equipment (Section 8.5). The redundant, seismic Category I isolation dampers in the control room and emergency switchgear relay rooms' area supply and exhaust air ducts close automatically in response to a safety injection signal. On the loss of power, the dampers fail to the closed position. The dampers can also be closed by remote manual operation. To minimize MCR Pressure Envelope Inleakage, the non-safety related ventilation fans which serve adjacent spaces to the envelope are automatically stopped upon closure of the isolation dampers. Safety-related pressure differential indicators have been installed in the envelope to verify positive pressure with respect to adjacent spaces.

HEPA filters are installed before the charcoal adsorbers to prevent clogging of the charcoal adsorbers. The charcoal adsorbers are installed to reduce the potential intake of radioiodine to the control room. When performed, the in-place test results should indicate a system leak-tightness of less than 1% bypass leakage for the charcoal adsorbers and particulate removal efficiency of at least 99.5% for the HEPA filters. New charcoal adsorbent for the emergency ventilation is qualified as discussed in Section 9.13.2 for safety-related filters. The adsorbent is replaced every 720 hours of use or following painting, fire, or a chemical challenge while running. The control room dose calculations for the design basis accidents assume a 90% elemental iodine removal efficiency and a 70% organic iodine removal efficiency for the air passing through the charcoal filters. Therefore, if the efficiencies of the HEPA filters and charcoal adsorbers are demonstrated to be as specified, at flow rates, velocities, and temperatures within the design values of the system, the resulting doses will be less than the allowable levels stated in 10 CFR 50.67.

10 CFR 50 Appendix R requirements and control room fire protection provisions are discussed in Section 9.10.

9.13.3.7 **Auxiliary Ventilation Control Panel and Annunciator**

The auxiliary ventilation control panel (VNTX) and annunciator is located in the control room area. The panel consists of an instrument nest and relay section, and a control indication section.

The control and indicating section contains control switches and indicating lights. The indicating lights are arranged in a mimic display on the panel front, and monitor damper position and ventilation system status and alignment. The control switches are required for filter/unfilter system alignment and to defeat the ventilation system realignment in response to a safety injection signal. Further discussion of defeating the automatic alignment feature of the ventilation system is in Section 9.13.4.1. This condition is not expected however, since defeating the automatic realignment is no longer credited in the fuel handling accident analysis and procedural controls have been established to eliminate operating with automatic alignment defeated.

Also located on the indicating and control section is the auxiliary ventilation system filtered exhaust fan controls and instrumentation.

The instrumentation includes a vane actuator control station and discharge flow indicator for each fan. This provides the operator with exhaust filter status, capacity control, and flow indication.

9.13.3.8 **Laundry Facility Ventilation**

The laundry facility ventilation is subject to possible radioactive contamination. The combined airborne effluent from the laundry facility (i.e., dryer exhaust, hood exhaust, and HVAC exhaust) is passed through HEPA filters before it exits the facility. The exhaust flow rate is 16,000 cfm. To assure that no unmonitored releases occur, the airborne exhaust, downstream of the HEPA filters is continuously monitored.

9.13.3.9 **TSC Ventilation**

The TSC spaces expected to be occupied are maintained at a positive pressure, post event, by turbine building air drawn through roughing, HEPA, and charcoal filters at a nominal 1000 cfm. The filter automatically starts on an SI signal and the normal air supply and exhaust are double-damper isolated. A positive pressure is maintained in the TSC spaces, as indicated on installed gauges, to ensure that no inleakage occurs.

9.13.3.10 **LEOF Ventilation**

The LEOF may be pressurized with outside air drawn through roughing and HEPA filters. The LEOF is manually activated post event and habitability determined by surveys performed as part of activation. The CEOF will replace the LEOF if necessary.

9.13.4 Design Evaluation

The ventilation systems in areas of potential contamination provide contamination control by ensuring that air is not recirculated, that 10 or more air changes per hour are supplied, and that the air is supplied to the least likely areas to be contaminated for circulation to and exhaust from locations subject to the greatest contamination potential. After being monitored for gaseous and particulate activity, the systems are exhausted through a ventilation stack discharging upward at a velocity in excess of 4000 fpm. A capability is provided for all nuclear auxiliary exhaust systems subject to airborne radioactive contamination to be realigned through roughing, particulate, and activated charcoal filters.

The ventilation system limits summer space temperatures to 105°F in occupied spaces and 120°F in normally unoccupied machinery spaces. Ventilation is based on the heat-producing equipment operating, and summer space temperatures will be lower whenever such equipment is down for maintenance.

The heating system provides space temperatures sufficient for winter operations and/or the inhibition of condensation in the fuel building and spaces below grade.

The MCR and emergency switchgear and relay rooms' area is completely enclosed in a tornado-proof and missile-proof concrete structure that requires air conditioning for operation. Each of the two redundant air handling units within each area is served by one of two chillers powered from the same power source (normal and emergency).

9.13.4.1 **Incident Control**

The safeguards area and charging pump cubicle exhausts to ventilation vent no. 2 are automatically realigned through the safety related particulate and iodine filters upon a safety injection signal unless the re-alignment is defeated due to the movement of irradiated fuel in the spent fuel pool. This condition is not expected however, since defeating the automatic realignment is no longer credited in the fuel handling accident analysis and procedural controls have been established to eliminate operating with automatic alignment defeated. If re-alignment is not defeated and a safety injection signal is received, the signal produces common pneumatic safety signals that cause the running exhaust fans to trip. Various air-operated and motor operated dampers are automatically repositioned to redirect exhaust flow through the safety related filters. The high capacity, safety related fans are automatically started. Except for the decontamination building, inward leakage is ensured, as the supply fans are shutdown. In the event of leakage from the recirculation spray system, or the low-head and high-head safety injection systems during recirculation mode transfer, airborne radioactivity would be removed from the safeguards area and from the exhaust ventilation stream from the charging pump cubicles by these filters. Ventilation fans and dampers receiving a safety injection signal require operator action to return the component to its non-safety mode upon reset of the safety injection signal.

Defeating the automatic alignment feature requires that, in the event of a LOCA, manual actions are required by the operator to re-enable the automatic alignment of the ventilation system to the safety related filters to process the exhaust from the safeguards area and charging pump cubicles following actions to secure fuel handling activities (Reference 1). Following a safety injection signal, an alarm is received in the MCR after a time delay if the automatic re-alignment is defeated.

During refueling, the fuel building and containment exhaust may be diverted through the two safety-related filter trains. However, there is no requirement to filter the exhaust since filtration is not credited in the fuel handling accident analysis. This will remove airborne particulate radioactivity.

If a high-radiation alarm from the ventilation vent continuous monitor occurs, the control room operator will:

1. Trip any operating supply fans and exhaust fans for:
    a. Auxiliary building central area
    b. Auxiliary building general area
    c. Fuel building
    d. Decontamination building
    e. Unit 1 safeguards
    f. Unit 2 safeguards

2. Locate source of activity by:

    a. Aligning auxiliary building exhaust to nonsafety charcoal filter

    b. Aligning remaining areas to safety-related filter or filters while maintaining filter flows within desired range

3. When the source area is detected, this area remains on filtered exhaust. Additional areas may be filtered as needed to keep filter flow within design range.

4. Request Health Physics to:

    a. Verify area evacuated as necessary,

    b. Control area access as necessary,

    c. Survey area, and

    d. Investigate cause.

The MCR may be isolated as necessary.

There are seven flow streams connectable to the safety related filters. The fuel building and either containment purge may be individually filtered by a single filter train. The volumetric flow may be less than 32,400 cfm but will remain above the fan low flow trip setpoint. The lower flow increases the residence time in the charcoal.

Except as noted above, and in Section 9.13.1, the flow through the safety related filters is procedurally controlled in the design range between 32,400 cfm and 39,600 cfm. Up to three areas may be filtered simultaneously by a single train.

For a discussion of incident control during containment purging or refueling, see Section 5.3.1.3.4.

In the event of a LOCA, the control room and emergency switchgear and relay room's area is sealed off by closing the weather-stripped access doors and the pressure-tight external duct closures at the space boundaries and internal fire barriers. The duct closure is automatic from a safety injection signal or can be closed from the control room by hand switches. The ventilation fans which serve adjacent spaces to the MCR will automatically shutdown to minimize inleakage into the MCR. A handswitch has been provided in the MCR if manual stopping is required. The air conditioning will continue to operate normally without change. Within 1 hour of control room envelope isolation, procedures require the alignment of the control room emergency ventilation system to provide a filtered breathing air supply to the control room envelope. The emergency ventilation is filtered through a roughing filter, a HEPA filter, and iodine adsorbers. All functions can be manually controlled from the control room ventilation control board.

Incipient fires in the control and emergency switchgear and relay room's area will be extinguished with portable equipment. If a fire becomes uncontrollable, the affected space will be isolated by closing the fire doors. The air-conditioning ductwork is self-contained within each space, and the closures in the replenishment air and exhaust ducts fitted at each fire barrier will prevent smoke contamination in adjacent spaces. The motor operated normal supply dampers may be closed should smoke enter the control room from outside the control room area. If the control room becomes untenable because of fire or smoke, the reactor units can be controlled in the hot shutdown mode from their respective auxiliary control areas in the emergency switchgear rooms.

9.13.4.2 **Malfunction Analysis**

To assure that potential contaminated air flows from areas of low potential to high potential, selected supply fans are procedurally controlled to operate only when sufficient air is being exhausted. For example, the larger Fuel Building supply fan cannot be operated unless both unfiltered exhaust fans are running or the building is on filtered exhaust. Exhaust fans whose operation could potentially lead to unmonitored releases are procedurally controlled to preclude operation or abandoned in place.

The total flow is measured in ventilation vent no. 2 and displayed within the MCR. Status lights are also provided in the MCR for each fan connected to the vent. If a fan becomes inoperative, a change will be indicated in the total flow. Where applicable, procedural controls have been established to preclude operating a supply fan when one of a pair of associated exhaust fans is not operating.

Each Unit’s MCR and emergency switchgear and relay room is equipped with two 100% capacity air handling units for a total of eight AHUs. The eight AHUs are arranged in two separate chilled water loops (4 AHUs on each loop), and either one or both chilled water loops are operated, as necessary, to maintain space temperatures. With only one loop in operation, one chiller provides chilled water to all operating AHUs. With both loops in service, two chillers provide chilled water separately to each loop, but only two AHUs are operating on each loop. The air handling units’ fans are started from inside the MCR. The MCR and emergency switchgear and relay room air conditioning system includes five 100% capacity chillers.

9.13.5 Tests and Inspections

The systems are inspected, tested, and balanced upon installation, and tested periodically thereafter. Operating hours are equalized on redundant systems. Particulate and charcoal filters are individually tested by the manufacturer after fabrication and again after installation. Replacement filters are tested in the same manner. Filter banks can be tested for leakage and dioctylphthalate (DOP) smoke test efficiency while in place, and defective cells identified for removal and replacement. Equipment installed for emergency use is tested during installation and operated monthly thereafter to ensure proper functioning.

Individual filter assemblies are periodically tested in accordance with Technical Specifications. In addition, equipment has been installed to allow regular monitoring of the filters. This equipment includes filter differential pressure indication, view ports, inside lights, inside and outside shrouds, and test ports. Not all of the filters contain all of the above monitoring equipment, but most filters can be monitored directly.

The two safety-related filter trains have 18 charcoal canisters installed in parallel with the main adsorber tray banks. The canisters are filled with the same adsorbent as the main adsorber trays and are removable from the outlet plenum for laboratory analysis. Charcoal analysis is to be performed every 720 hours of safety-related filter operation.

9.13 REFERENCES

1. Letter from B. C. Buckley of the NRC to W. L. Stewart of Vepco, dated November 20, 1992 (Serial No. 92-773), *Operation of the Auxiliary Ventilation System.*

9.13 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FB-5A	Arrangement: Primary Plant Systems, Ventilation
2.	11448-FB-5B	Arrangement: Primary Plant Systems, Ventilation, Unit 1
3.	11448-FB-24A	Arrangement: Service Building, Ventilation, Floor Elevations 27'-0" & 9'- 6", Columns 4 through 19
4.	11448-FB-24B	Arrangement: Service Building; Ventilation; Floor Elevations 42'-0", 45'- 3", 47'- 0", & 58'- 6"; Columns 2¼ through 13½
5.	11448-FB-006D	Flow/Valve Operating Numbers Diagram: Auxiliary Ventilation System, Units 1 & 2

Table 9.13-1
MAIN CONTROL ROOM AND EMERGENCY SWITCHGEAR AND RELAY ROOM VENTILATION AND AIR CONDITIONING SYSTEMS DESIGN DATA

Service	Number of Units	Unit Capacity, cfm	Static Pressure, in. W.G.	Motor, hp	Refrigeration Capacity, MBh	Filter Type
U1 Control room air conditioning	2	9,000[b]	4.0	10	210	Cartridge
U2 Control room air conditioning	2	9,500[b]	4.0	15	335	Cartridge
Unit 1 relay room air conditioning	2	10,500[b]	6.0	20	635	Cartridge
Unit 2 relay room air conditioning	2	10,500[b]	6.0	20	635	Cartridge
Control and relay room air supply		3000	(Branch from assembly room unit)			Roll
Control and relay room area exhaust	1	3000 [a]	2.5	2	-	-
Control room emergency ventilation	2	1000	4	1.5	0	Charcoal
Unit 1 relay room emergency ventilation	1	1000	4	1.5	0	Charcoal
Unit 2 relay room emergency ventilation	1	1000	4	1.5	0	Charcoal

a. Operational condition - throttled to maintain control room positive pressure with boundary doors closed.
b. Minimum air flow required to maintain design ambient conditions following a bounding event in accordance with calculation ME-0931, Revision 0.

Figure 9.13-1
VENTILATION ARRANGEMENT: PRIMARY PLANT

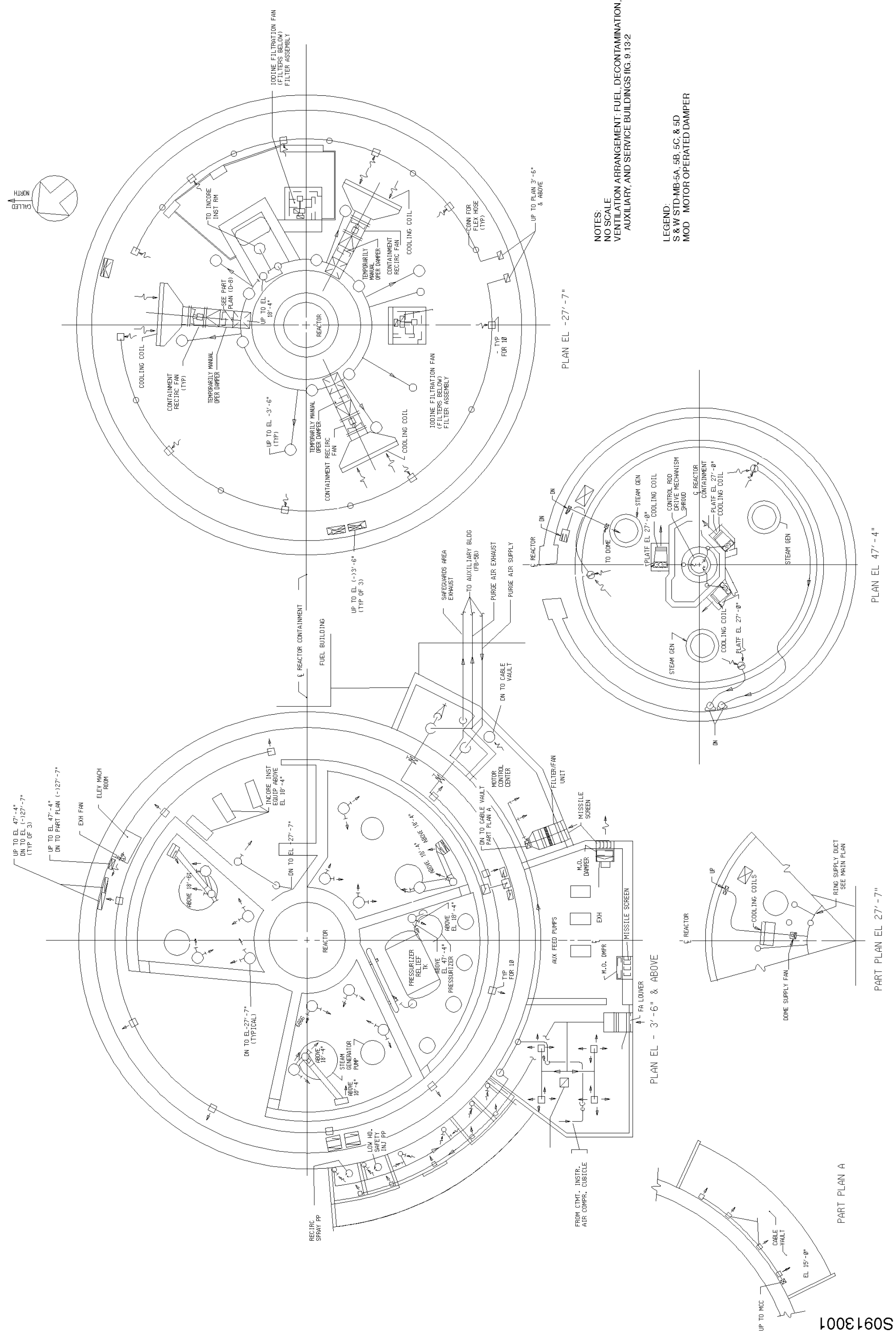


Figure 9.13-2
VENTILATION ARRANGEMENT: FUEL, DECONTAMINATION, AUXILIARY, AND SERVICE BUILDINGS

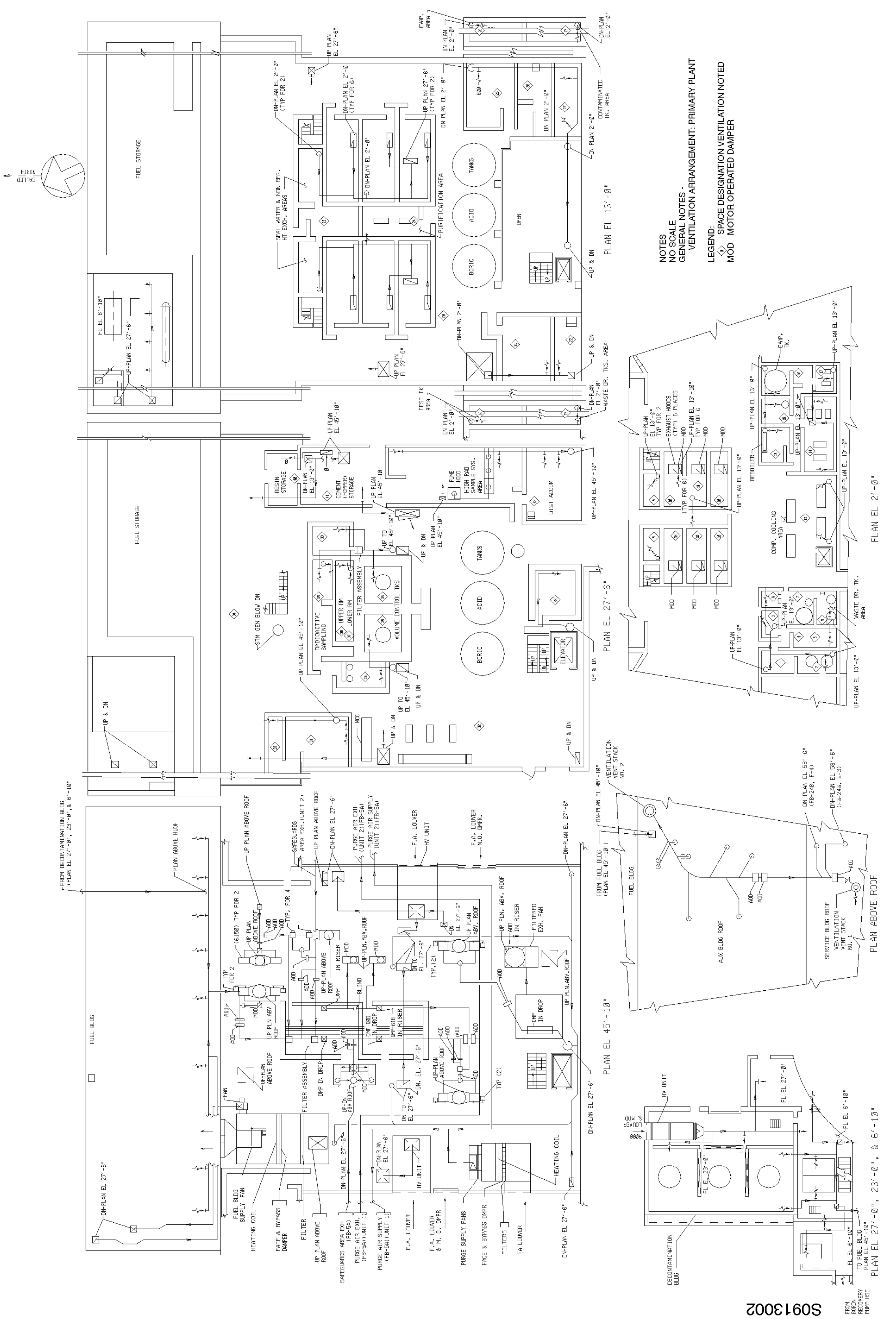
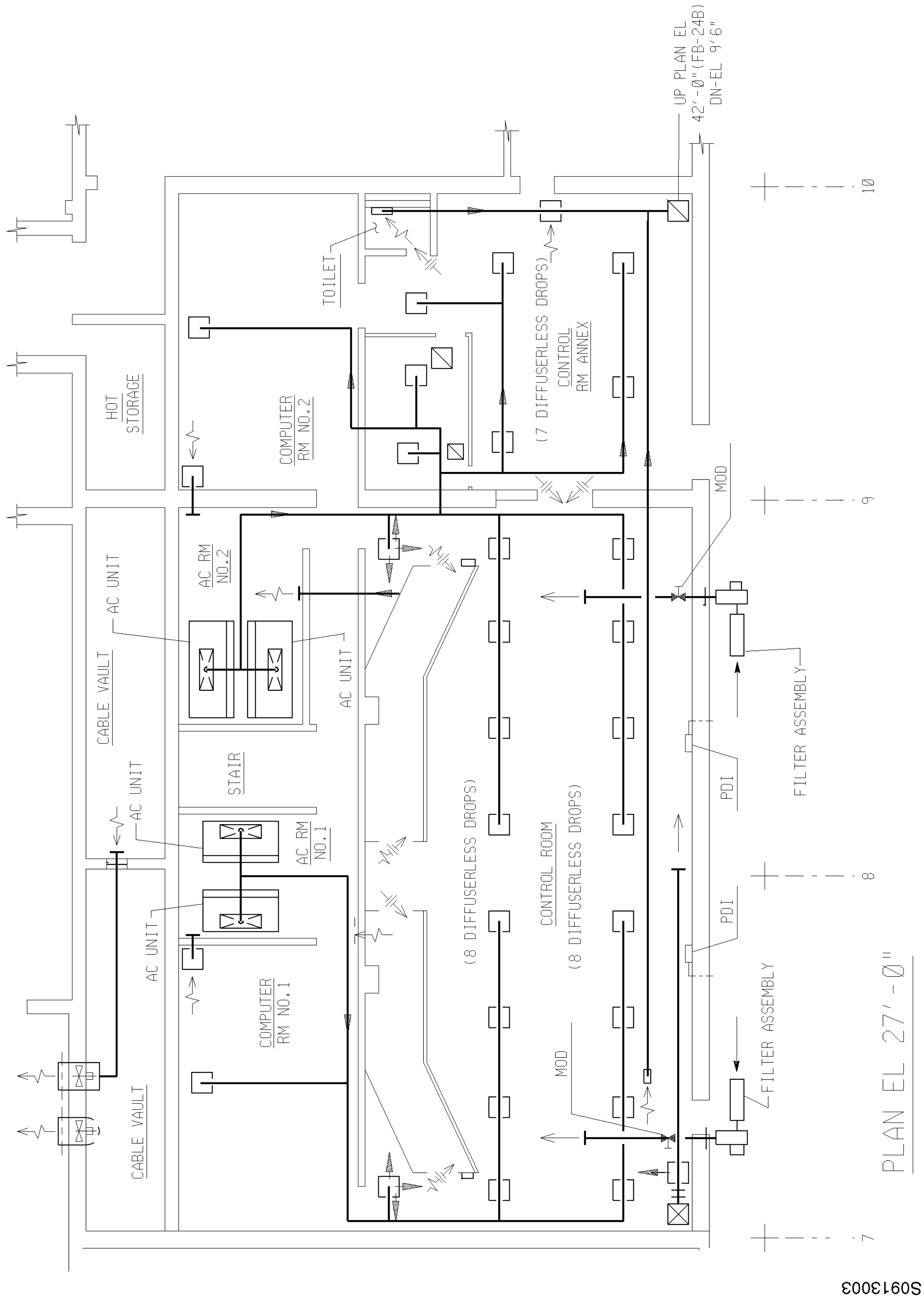


Figure 9.13-3
VENTILATION ARRANGEMENT: CONTROL ROOM



9.14 DECONTAMINATION FACILITY

The decontamination facility (Reference Drawing 1) is a poured-concrete and concrete-block structure on the north side of the fuel building, under the fuel cask trolley rails. This location makes it accessible for transporting in and out of the building major items to be decontaminated. Roof hatches and a rolling steel door provide access for equipment.

9.14.1 Design Bases

The facility is designed to provide an area in which equipment can be decontaminated and spent fuel dry storage casks can be prepared for storage without releasing activity to the environment in an uncontrolled manner. Decontamination procedures are specified to reduce surface contamination to a level such that the components can be handled in a safe manner. Certain decontamination activities (such as deconning small tools and equipment) are performed at the Radwaste Facility.

9.14.2 Description

The decontamination building is a poured-concrete and concrete-block building abutting the east end of the fuel building's north wall. A 125-ton trolley runs through a high-bay portion of the building immediately adjacent to the fuel building, and over the roof for the remainder of the decontamination building. Three roof hatches permit casks or other objects to be lowered from the trolley into the building. A tramrail in the building permits the movement of small parts between work areas and tanks with minimum personnel exposure. A T-shaped rolling steel door encloses the high-bay area from the outside when the trolley is not in use. The fuel building and decontamination building are separated by a weathertight structural gap to permit independent motion of the buildings in the event of an earthquake.

Ventilation air is exhausted from the decontamination building through the monitored ventilation vent no. 2. On a high alarm by ventilation vent no. 2 monitors, the decontamination exhaust is remote-manually diverted through charcoal filters as described in Section 9.13. The exhaust capacity is greater than the supply capacity of this system, thus producing a slightly negative pressure in the buildings, so that all air leakage is inwards.

Liquid wastes from decontamination work are piped to the liquid waste disposal system (Section 11.2.4) for processing.

The interior surfaces of the building are covered with suitable materials to permit easy decontamination. A stainless steel pad is provided to protect the floor under heavy objects. Hose connections are provided for compressed air and primary-grade water at each work area. The various decontamination methods provide a flexibility that will give the best decontamination for a specific job, minimize personnel exposure, and limit the release of radioactive material to the environment. Technical information on the equipment provided in the facility is given in Table 9.14-1.

Spent ion exchanger resins can also be processed in the decontamination building via the spent resin catch and blend tanks and their associated transfer pumps. The operation of this equipment and component data are provided in Section 11.2.4.

Final preparations for the spent fuel storage casks takes place in the north bay of the decontamination building. These final preparations consist of decontamination of the external cask surfaces, vacuum drying of the cask interior to remove residual spent fuel pool water, backfilling the cask cavity with helium, placement of the cask secondary lid as applicable, and testing the cask seals for leak-tightness.

To facilitate these preparations, a permanent work platform is installed. The work platform is a two-level platform located in the north bay of the decontamination building. The platform is designed with swing-up sections to facilitate cask entry and to preclude any potentially hazardous openings in the flooring. The cask, which has been loaded with spent fuel assemblies in the spent fuel pool and transferred to the decontamination building via the 125-ton trolley, is lowered into the opening in the work platform.

A piping system is used to remove the Spent Fuel Pool water from the fuel storage Dry Shielded Canister (DSC) prior to vacuum drying. The system is manually operated and consists of a centrifugal DSC Drain Pump, flow indicator, valves and piping routed from the DSC to below the surface of the Spent Fuel Pool water. Additionally, if required, a DSC Reflood Pump is provided to fill the canister with Spent Fuel Pool water. This system consists of a self-priming centrifugal pump, flow indicator, valves and piping routed from below the Spent Fuel Pool water surface to the DSC.

A Vacuum Drying System (VDS) is installed near the DSC (Dry Shielded Canister) on the working level platform Elevation 37 ft. 0 in.). The VDS is a single skid mounted computer controlled unit with monitor and all the necessary valves, pumps, moisture separator tank, cooling and heating systems, flow meters, pressure and vacuum gauges and external boom connections to facilitate vacuum drying, draining, reflooding and helium back filling of the DSC. The VDS is capable of performing draining and reflooding of the DSC in addition to the installed DSC drain pump and DSC reflood pump.

The discharge from the VDS vacuum exhaust is piped to the decontamination building ventilation system. This ventilation system monitors the air discharged from the decontamination area for radioactive contamination and has the equipment available for removing radioactive contaminants from the air steam, should the need arise.

The helium system is made up of a helium bottle rack containing helium bottles, and is located in the crane enclosure. From this bottle manifold, helium is piped to the VDS. The VDS supplies helium to the DSC for helium backfilling through boom piping.

Nitrogen bottles located in the crane enclosure are piped from a manifold to the VDS. Nitrogen is utilized by the VDS for operation of its internal pneumatic valves, to purge collected moisture from the VDS vacuum pumps and piping, and for pneumatic operation of the moisture separator tank drain and vent valves.

9.14.3 Design Evaluation

The facility provides a contained area with all discharges controlled to prevent the inadvertent release of activity to the environment.

In the event of leakage from piping or equipment, areas of the building are provided with sumps to which fluids will drain. The sumps discharge to the liquid waste disposal system. Airborne particulate matter is retained within the building because of the slightly subatmospheric pressure, and is discharged in a controlled manner through the monitored ventilation vent no. 2.

9.14.4 Tests And Inspections

Periodic tests are conducted on the radiation detection equipment in the ventilation system.

Operating equipment and storage tanks are subjected to periodic visual inspections.

9.14 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-10B	Arrangement: Decontamination Building, Sheet 1

Table 9.14-1
DECONTAMINATION FACILITY COMPONENT DATA[a]

DSC Drain Pump	
Number	1
Type	Centrifugal, Canned Motor Pump
Motor Horsepower	3
Seal Type	Sealless
Capacity	25 gpm
Total Dynamic Head	52 feet
Rotating Speed	1750 rpm
DSC Reflood Pump	
Number	1
Type	Centrifugal, Self-priming, Magnetic Drive
Motor Horse Power	2
Seal Type	Sealless
Capacity	30 gpm
Total Dynamic Head	54 feet
Rotating Speed	3550 rpm

a. Spent resin processing components' data are provided in Section 11.2.

Appendix 9A
High-Density Spent-Fuel Storage Rack Design

Intentionally Blank

APPENDIX 9A HIGH-DENSITY SPENT-FUEL STORAGE RACK DESIGN

9A.1 DESIGN BASES

The high-density spent-fuel storage racks are designed to provide vertical storage locations for up to 1044 irradiated fuel assemblies, including insert components, in a borated water pool (with a boron concentration not less than 2300 ppm). The racks are designed to maintain the stored fuel, having maximum initial uranium enrichment of 4.3 weight percent U-235 in UO_2, in a safe, coolable, and subcritical configuration under all conditions.

The reinforced concrete structure and steel superstructure of the Fuel Building and spent fuel storage racks are designed to withstand Design Basis Earthquake loadings as Class 1 structures. The spent fuel pool has a stainless steel liner to protect against loss of water.

The spent fuel pool is divided into a two-region storage pool. Region 1 includes the first three rows of fuel racks (324 storage locations) adjacent to the Fuel Building Trolley Load Block. Region 2 contains the remainder of the fuel racks in the fuel pool. During spent fuel cask handling, Region 1 is limited to storage of spent fuel assemblies which have decayed at least 150 days after discharge and will be restricted to those assemblies in the “acceptable” domain as described in Technical Specification 5.4.

9A.2 STORAGE RACK DESCRIPTION

The spent fuel pool is a seismic Category I structure. Its primary function is to store spent fuel assemblies. The spent fuel pool is a 72 ft. 6 in. long, 29 ft. 3 in. wide and 40 ft. 6 in. deep reinforced concrete structure resting on a pile foundation. The floor and walls of the pool are nominally 6 feet thick. The pool is lined with 0.25-inch thick stainless steel liner plate. The spent fuel cask loading area (12 ft x 12 ft) is located at the northeast end of the pool. The floor of the cask loading area is 2 ft. 6 in. lower than the pool floor. The cask pad sits in this area.

Each fuel storage rack consists of a 6 x 6 array of fuel storage cells, which are square stainless steel boxes spaced nominally 14 inches on centers. The rack is shown on the general arrangement drawing, Figure 9A-1.

The fuel storage rack has two basic components: the support structure and the fuel storage cell. The support structure consists primarily of the four corner storage cells, which interface with the spent-fuel pool floor pads, and two horizontal grid members, which are supported by the four corner cells and which maintain the horizontal position and vertical alignment of the remaining 32 (inner) storage cells. The inner storage cells rest directly on the spent-fuel pool floor. Diagonal bracing is provided on the structure to accommodate the loads imposed by rack installation, by fuel handling, and by seismic events.

Horizontal seismic loads are transmitted from the rack structure to the spent-fuel pool floor through restraint devices that capture the existing spent-fuel pool floor pads and mate with the fuel rack structure corner cells. The restraint devices also permit leveling of the fuel racks, and require no modification of the existing fuel rack support pad. The vertical seismic loads are essentially transmitted directly to the pool floor by each storage cell. No bracing to the pool wall is required to support the racks during a seismic event. The racks, however, are connected to each other at the top grid to preclude potential uplift.

Each corner storage cell is nominally 9.56 inches by 9.56 inches (o.d.) by approximately 172 inches long, with 0.250-inch walls. Each of the 32 inner storage cells is nominally 9.12 inches by 9.12 inches (o.d.) by approximately 170 inches long, with 0.090-inch walls. The cells are flared at the top to aid in insertion of the fuel assembly into the cell. Attached to the bottom of each cell are four stainless steel posts that support the fuel assembly. The posts attached to the 32 inner cells rest directly on the floor of the spent-fuel pool and space the cells off the pool floor a sufficient distance to ensure adequate area for cooling flow. To accommodate any unlevelness in the pool floor liner, the rack is designed to permit the inner cells to move vertically within the rack structure (a ±1-inch motion is provided). The inner cells, however, are positively locked into the support structure so that they cannot be inadvertently lifted out of the rack.

The corner cells rest on adapter plates. The adapter plates are keyed to the existing rack stops, and the corners of the fuel storage cells are keyed to the adapter plates through 1-5/8-inch-diameter restraint pins. For installation purposes, a nominal clearance of 1/16 inch is provided all around between the restraint pin hole in the corner storage cells and the restraint pin, and between the clearance cutouts in the adapter plates and the existing rack stops. The clearance also provides sufficient allowance for thermal expansion. Horizontal seismic loads are transmitted from the rack structure to the existing rack stops at each corner of the rack through the adapter plates and pins. The racks cannot slide during any design-basis seismic event.

There is no interference between the spent-fuel storage racks and the gates and tools in storage within the pool. All of the equipment stored within the fuel pool, except the refueling canal gates, weighs less than a fuel assembly. Therefore, any possible interaction between these tools and the fuel racks would be less severe than interaction between a fuel assembly and the spent-fuel storage racks, which has been analyzed. The refueling canal gates, however, weigh approximately 3200 lb, which is more than a fuel assembly. These gates are stored so as to be captured at both the top and the bottom, making interaction between the gate and the spent-fuel storage racks very unlikely.

The rack grids maintain the horizontal position of the inner cells relative to each other and the corner cells so that impact between inner cells and/or corner cells is not possible. Each grid consists of welded 4 inches by 1.5 inches by 3/16 inch channels forming square openings in which the inner cells are placed. The grids are welded to the top and bottom ends of the heavy wall (0.25-inch thick) corner storage cells to form the basic rack structure. Diagonal bracing welded to the corner storage cells completes the rack structure and provides the lateral and torsional rigidity to accommodate seismic and installation loads.

At each grid elevation, four angle clips capture the corners of each inner cell. These clips are welded to the channel members of each grid to maintain pitch and vertical plumbness. A slight clearance is provided between the clips and the cells (1/64-inch maximum for each clip) to facilitate fabrication and to permit vertical movement of the inner cells. Such vertical movement does not introduce any stresses/deformations in the rack structure or the inner storage cells, since each inner cell can move freely past the grid retaining clips to sit directly on the pool floor. The design permits the vertical loads for each inner cell to be transmitted to the pool floor. It is necessary to limit the vertical travel of the inner storage cells to prevent (1) removal of a cell during fuel-handling operations (e.g., stuck fuel assembly load case) and (2) a cell dropping out of the rack during rack installation/removal. Mechanical stops welded to each inner cell limit the total vertical travel to about 2 inches (±1 inch). These stops will support the weight of the fuel cell plus a fuel assembly if necessary.

A fuel assembly guard structure is provided to prevent a fuel assembly from being brought up against the side of the peripheral fuel racks wherever the space between the fuel racks and the fuel pool walls is sufficient to insert an assembly. The structure is a 4 inches by 2 inches by 3/16 inch angle welded to the outside channel of the upper grid. With this structure in place it will not be possible to move a fuel assembly closer than approximately 8 inches to stored fuel, thereby maintaining a pitch in excess of 17 inches for this condition. The guard structures are required on the east and west sides of the storage rack array, and on the two racks adjacent to the Unit 2 refueling canal. The space between the fuel racks and the north or south walls is not sufficient to insert a fuel assembly.

9A.3 STORAGE RACK EVALUATION

9A.3.1 Structural and Seismic Analysis

The high-density fuel storage racks are designed to meet the requirements for Seismic Class I structures. Detailed structural and seismic analyses of the high-density storage racks have been performed to verify the adequacy of the design to withstand the loadings encountered during installation, normal operation, the severe and extreme environmental conditions of the operating-basis and safe-shutdown earthquakes, and the abnormal loading condition of an accidental fuel-assembly-drop event.

The ground acceleration values in Section 2.5 were used to generate the amplified response spectra used in the design of the spent-fuel racks. A dynamic model representing the fuel building structure and the subgrade was prepared. This model was used to calculate amplified response spectra (ARS) due to the specified earthquake. Amplified response spectra were generated for both the safe-shutdown earthquake and the operational-basis earthquake (one-half of the safe-shutdown earthquake) at the mat surface, the top of the concrete structure, and the roof of the steel superstructure. The response spectra of the design earthquakes used are consistent with the requirements set forth by NRC Regulatory Guide 1.60, and the damping levels are from NRC Regulatory Guide 1.61.

The dynamic analysis was performed for a range of subgrade properties to account for uncertainties in soil parameters. The amplified response spectra provided are the result of enveloping the response spectra obtained from these analyses. They also include the design ground response spectrum.

The various load combinations considered in the design of the high-density fuel storage racks and the allowable stress values for these load combinations are given in Tables 9A-1 and 9A-2, respectively. The yield stress value for stainless steel used in calculating the section strength for all the load combinations was taken as 30.0 ksi.

9A.3.1.1 **Applicable Codes, Standards, and Specifications**

The applicable codes, standards, and specifications used in the design, fabrication, inspection, installation, and evaluation of the high-density fuel storage racks are given below.

1. Design: A.I.S.C. Manual of Steel Construction, Seventh Edition, 1970.
2. Fabrication:
   a. ASME Code, Section VIII.
   b. ASME Code, Section IX, Welding and Brazing Qualifications.
3. Inspection: ASME Code, Section V, Nondestructive Examination.
4. Installation:
   a. ASME Code, Section VIII, Appendix 9.
   b. ASME Code, Section IX.
5. Evaluation:
   a. USNRC Regulatory Guide 1.60, *Design Response Spectra for Seismic Design of Nuclear Power Plants*, December 1973.
   b. USNRC Regulatory Guide 1.61, *Damping Values for Seismic Design of Nuclear Power Plants*, October 1973.
   c. USNRC Regulatory Guide 1.92, *Combination of Modes and Spatial Components in Seismic Response Analysis*, Revision 1, February 1976.

9A.3.1.2 **Loads and Load Combinations**

The following load cases were considered in the analysis, in accordance with the requirements of USNRC Standard Review Plan, Section 3.8.4, *Other Seismic Category 1 Structures*.

1. Dead weight of rack plus corner fuel assemblies, D + L (normal load) - Under normal operating conditions, the rack is subjected to the dead weight loading of the rack structure itself plus the loads resulting from four fuel assemblies stored in the four structural corner cells. The loads resulting from the individual storage cells and contained fuel assemblies are not considered, since these transmit their load directly to the pool floor and not through the structure.
2. Dead weight of rack and storage cells, D + I.L. (normal load) - During installation, the rack is subjected to the loading resulting from its own structural weight plus the weight of the empty storage cells.
3. Operating-basis earthquake, E (severe environmental load) - The rack, fuel assemblies, and virtual water mass react to the simultaneous loading of the horizontal and vertical components of the seismic response acceleration spectra specified for the operating-basis earthquake in the Surry 1 and 2 seismic design specifications. The seismic loading is applied to two storage conditions: a fully loaded rack, and a partially loaded rack with 21 assemblies.
4. Safe-shutdown earthquake, E' (extreme environmental load) - Same as Load Case 2, except the seismic response acceleration spectra corresponding to the safe-shutdown earthquake were used in the analysis.
5. Uplifting load, U.L. (abnormal load) - The possibility of a fuel assembly becoming jammed in a fuel storage cell during fuel handling was considered. The uplift force considered for this load case is the maximum force that can be applied by the fuel-handling bridge fuel hoist (4000 lb) less the weight of the jammed fuel assembly and the fuel storage cell (combined weight is 1650 lb). The uplift force used in the analysis (2400 lb) is very conservative, since the fuel hoist has a load-limit cell set at 2000 lb. With such a load-limit device, the net uplift force would be about 350 lb. No credit was taken for operation of the load-limit cell.
6. Assembly drop impact load, F.I. (abnormal load) - The possibility of dropping a fuel assembly on the rack from the highest possible elevation during spent-fuel handling was considered. A 2000-lb weight was postulated to drop on the rack from a height of 42 inches.

For the service load cases described above, the following load combinations were considered, using elastic working stress design methods of the AISC:

D + L	(Load Case la)
D + I.L.	(Load Case lb)
D + L + E	(Load Case 2)

For the factored load cases described above, the following load combinations are considered, using elastic working stress design methods of the AISC:

D + L + E' (Load Case 3)

D + U.L. (Load Case 4)

D + F.I. (Load Case 5)

9A.3.1.3 **Design and Analysis Methods**

9A.3.1.3.1 Static Analysis

The response of the rack structure to specified static loading conditions was evaluated by means of linear-elastic analysis using the finite element method. The rack was mathematically modeled as a three-dimensional finite element structure consisting of discrete three-dimensional elastic beams and plates. Six degrees of freedom (three translations and three rotations) were permitted at each nodal point. Appropriate boundary conditions were assumed for each load case.

9A.3.1.3.2 Dynamic Analyses

The response of the rack structure to specified seismic loading conditions was evaluated by mathematically modeling the storage rack as a lumped mass, multi-degree-of-freedom system. The fuel storage rack structure has been mathematically modeled as a three-dimensional finite element structure consisting of discrete three-dimensional elastic beam and plate elements interconnected at a finite number of nodal points. Masses were lumped so as to represent the dynamic characteristics of the storage racks. The eigenvalues and eigenvectors (frequency and mode shapes of vibration) of the lumped mass model were calculated using the Householder-QR technique.

The seismic response analyses were then performed using response spectrum modal superposition methods of dynamic analysis, using the Surry amplified response spectra and appropriate damping for welded steel structures. The damping values used in the seismic analysis of the high-density fuel storage racks are 4% for the operating-basis earthquake and 6% for the safe-shutdown earthquake. NRC Regulatory Guide 1.61 permits damping values of 2% for the operating-basis earthquake and 4% for the safe-shutdown earthquake for welded steel structures functioning in air. These damping values are increased by 2%, since the fuel storage racks are welded stainless steel structures completely submerged in water. This 2% increase in damping value for submerged structures is based on Section 6.4 of *Fundamentals of Earthquake Engineering* by N. M. Newmark and E. Rosenblueth.

The fuel storage rack (6 x 6 array of fuel storage cells) consists of upper and lower grid structures connected to each other by means of four corner cells and diagonal bracing members. The fuel storage rack thus structurally becomes equivalent to a box-shaped structure which is inherently strong in torsion. The torsional effects due to possible nonuniform mass distribution was considered by analyzing the partially loaded rack.

Individual modal responses of the system were combined in accordance with Section 1.2.1 of Regulatory Guide 1.92. The maximum responses of the system for each of the three orthogonal spatial components (two horizontal and one vertical) of an earthquake were combined on a square root of the sum of the square (SRSS) basis (Regulatory Guide 1.92).

The sloshing effects of water on the fuel racks were evaluated using the analytical methods given in the ASCEs *Structural Analysis and Design of Nuclear Plant Facilities*. The "rattling" effects of the fuel inside the cell were accounted for by increasing the seismic inertia loads produced by the impacting masses by applying an impact factor of two, and adding the resulting loading to the seismic inertial loading produced by the non-impacting masses.

The masses considered in the seismic analysis include the fuel assembly weight, the storage cell weight, structural member weight, and tributary water mass. Of these masses, only the fuel assembly will produce impact. The fuel assembly will only impact the fuel storage cell at the top of the fuel assembly, since the fuel assembly will pivot on the bottom support pads. Therefore, the impact factor of two was applied to the seismic inertial loads produced by the upper half of the fuel assembly weight, resulting in an equivalent factor of 1.4 when the seismic inertia loads due to the total cell weight were considered. The equivalent loading (1.4 times the seismic inertia loads to account for fuel assembly impact effects) was considered for local effects as well as overall effects on the structural members of the rack, the rack/floor pad connection plates, and the floor pads.

The static, seismic, and stress analyses for the fuel storage racks were performed utilizing the STARDYNE computer code.

The fuel assembly drop load case (Load Case 5) was compared to the results from the refueling canal gate drop analysis. The results are discussed in Section 9A.3.1.5.

9A.3.1.3.3 Thermal Growth

The maximum thermal growth of the fuel storage racks would be 0.11 inch for a fuel pool bulk water temperature change from 70°F to 210°F. Sufficient clearance between the fuel storage rack and the pool floor support pads (0.125 inch minimum) has been provided to eliminate any potential interference between the rack and the support pads caused by thermal expansion. The installation approach permits those clearances to be achieved during wet installation of the Surry fuel racks. Since there will not be any interferences between the rack and its support points, the stresses and reaction loads due to thermal loadings would be insignificant. Furthermore, there will not be any local stresses due to thermal gradients across the fuel storage rack structural members, since significant increases in pool water bulk temperature occur very gradually (a change from 70°F to 210°F would take approximately 20 hours).

9A.3.1.4 **Structural Acceptance Criteria**

The following allowable limits constitute the structural acceptance criteria used for load cases 1 through 4 presented in Section 9A.3.1.2:

Load Combinations	Limit
1a and 1b	S
2	S
3	1.6S
4	1.6S

where S is the required section strength based on the elastic design methods and the allowable stresses defined in Part 1 of the AISC *Specification for the Design, Fabrication and Erection of Structural Steel for Buildings*, February 12, 1969.

9A.3.1.5 **Results of Analysis**

The results of the static structural analysis for load combinations 1 and 4 show that the deflections and stresses in the various structural members of the fuel storage rack are nominal and less than the applicable acceptance criteria.

The results of the seismic structural analyses for load combinations 2 and 3 show that the maximum stresses and deflections in the rack are nominal and within the allowable values. The maximum calculated stress is 8.3 ksi, which occurs in an upper grid member of the structure. The fundamental frequency of vibration of the fuel storage rack is 9.5 cps.

The results of the analysis for load case 5 indicate that the drop of a fuel assembly onto a fuel storage cell is bounded by the analysis of a drop of the refueling canal gate onto the fuel storage racks. Any buckling of the cells as a result of a fuel assembly drop would be limited to the top flared region of the cells. The predicted strains in the cells are not sufficient to alter the storage rack geometry after being subjected to a fuel assembly drop from 42 inches. Therefore, there will be no effect on keff of fuel stored in the rack as a result of a fuel assembly drop.

It could not be concluded directly from this analysis that perforation of the quarter-inch stainless steel spent fuel pool liner would not occur as a result of a fuel assembly drop. In the event that the liner is perforated as a result of a fuel assembly drop, the leak rate from the pool would be less than the makeup capability to the pool and fuel stored in the racks would not be uncovered as a result. Perforation of the spent fuel pool liner is addressed in the discussion of the Fuel Cask Trolley in Section 9.12.4.13.

The seismic and structural analysis shows that the deflections and/or stresses in the rack structure resulting from the various loadings meet the deflection and stress acceptance criteria for Seismic Class I structures.

The maximum stress values are given in Table 9A-1 for load combinations 1 through 4.

A summary of stresses of the supporting pool structure is provided in Table 9A-2.

The following load combinations were considered:

1. Hydrostatic + dead load + live load.
2. Hydrostatic + dead load + live load + operating-basis earthquake.
3. Hydrostatic + dead load + live load + safe-shutdown earthquake.
4. Hydrostatic + dead load + live load + high-density racks.

The allowable stresses are based on the minimum sampled coupon strength of 43,600 psi and the acceptance criteria stated in ACI 318-63. It should be noted that with the new high-density fuel storage racks, the mat loadings are lower than those originally calculated. This is due to the different analytical model used. For the high-density fuel storage rack loadings, the model accounted for the detailed location of both the pilings and the fuel rack embedments in the mat. This resulted in a significant portion of the load due to spent fuel being transmitted to the pilings without inducing mat bending. In the analysis for the original loading, the rack loads were spread uniformly over the mat, and the pilings were lumped at discrete locations that were further apart than the actual pile spacing. The method used to calculate the mat loadings from the new high-density fuel storage racks represents the as-built condition at Surry.

As given in Section 9.5, the spent-fuel pool temperature will be maintained at or below the original limits of 140°F (normal case) and 170°F (abnormal case). Therefore, the maximum temperature of the thermal gradient in the pool walls and the base slab as originally designed will not be exceeded.

9A.3.2 Nuclear Analysis

A detailed nuclear analysis was performed to demonstrate that for all anticipated normal and abnormal configurations of fuel assemblies within the fuel storage racks, the k_{eff} of the system is substantially subcritical ($k_{eff} < 0.95$). Certain conservative assumptions about the fuel assemblies and racks were used in the calculations. These assumptions are described in Section 9A.3.2.1.

The reference configuration which is the basis of the criticality calculations consists of an array of square stainless steel boxes (9.12 inches o.d. with a wall thickness of 0.090 inch) spaced 14.0 inches on centers with fuel assemblies centrally located within the boxes. Variations from this reference configuration were also studied and included the effects of dimensional and spacing variations, fuel enrichment changes, water temperature increases and mislocations of fuel assemblies and boxes. A description of the calculational method and codes is presented in Section 9A.3.2.3, and the results of the criticality analysis are presented in Section 9A.3.2.4.

The analysis of the Surry spent fuel racks followed the methodology described in Reference 9 and approved by the NRC in Reference 10. Differences between this approved methodology and the Surry analysis are described in Section 9A.3.2.3.1. Criticality calculations were performed using BONAMI and NITAWL-II codes for cross section generation, and the KENO-V.a Monte Carlo code for reactivity determination. Sensitivity calculations for normal and abnormal conditions were performed using the Westinghouse PHOENIX-P code.

9A.3.2.1 Design Criteria and Assumptions

The criticality design criterion established for the Surry Power Station spent-fuel racks is that the multiplication constant (k_{eff}) shall be less than 0.95 for all normal and abnormal configurations, as confirmed by transport theory.

The following conservative assumptions were used in the criticality calculations performed to verify the adequacy of the rack design with respect to the rack design criteria:

1. The pool water has no soluble poison.
2. The fuel assemblies have no burnable poison.
3. The fuel is fresh and of a specified nominal enrichment as high or higher than that of any fuel available.
4. No credit is taken for structural material other than the fuel can.
5. All fuel cans are assumed to be 0.090 inches thick, the minimum allowable thickness.

9A.3.2.2 Configurations Analyzed

The various configurations of fuel within racks that are possible are classed as either normal or abnormal configurations. Normal configurations result from the placement of fuel within racks and the variation in rack dimensions permitted in fabrication. Abnormal configurations are typically the results of accidents or malfunctions such as seismic events, malfunction of the fuel pool cooling system, etc.

9A.3.2.2.1 Normal Configurations

The normal configurations analyzed were: a reference configuration consists of an infinite array of storage cells having nominal dimensions each containing a 15 x 15 Westinghouse fuel assembly of nominal 4.25 weight percent enrichment positioned centrally within the cell. The 15 x 15 designed fuel assemblies were selected for reference configuration because racks with the 15 x 15 fuel assemblies are slightly more reactive than the rack with the 17 x 17 designed fuel assemblies with equal enrichment. The storage cells are 9.12 inches in outside dimensions, have 0.090-inch walls, and are spaced 14.0 inches on centers. The spent fuel pool water is assumed to be 170°F, which is the upper bound of normal operating temperatures. The effects of variations in material characteristics and physical dimensions are statistically incorporated into the keff for the spent fuel storage racks.

9A.3.2.2.2 Abnormal Configurations

Two types of accidents can typically occur in the spent fuel rack which can cause reactivity to increase. The first accident type involves a pool water temperature change, which involves an increase or decrease in the spent fuel pool water temperature and density. The second accident type involves a fuel assembly misplacement, where restrictions on location, enrichment, or burnup are not satisfied. Fuel assembly misplacement accidents include a fuel assembly drop on top of a rack, and a fuel assembly drop between rack modules or between a rack module and the spent fuel pool wall. It is also possible for a dropped fuel assembly to enter a box cleanly and impact directly on the fuel stored in the box. The effect of this type of fuel drop incident was considered from a criticality viewpoint in the initial evaluation for the high density fuel racks (Reference 3) by assuming that the stored assembly would be compressed axially. A calculation based on axial compression of 2 feet yielded a 0.06 decrease in k_{inf} of the fuel cell. Therefore, this type of fuel misplacement accident would reduce k_{eff} and was not considered further.

For Surry, a fuel storage cask handling accident was also evaluated. This accident scenario assumes a fuel storage cask rotates and falls against the fuel storage racks next to the cask loading area. To evaluate this accident, the spent fuel pool is divided into two regions. Region 1 comprises the first three rows of fuel storage racks (324 locations) adjacent to the fuel building trolley load block, which is susceptible to the storage cask handling accident. The remainder of the Surry spent fuel pool (Region 2) is unaffected by this accident.

The seismic impact on criticality calculations was also considered in the initial evaluation for the high density fuel racks. These analyses indicated that the maximum rack structure deflections will be very small (less than 0.120 inches). These deflections have a negligible effect on k_{eff} since they do not change the center-to-center spacing between the storage cells or boxes significantly. The maximum deflection of the storage cells or boxes due to a seismic event occurs at the middle of the box and is less than 0.050 inches. The effect of box deflections on k_{eff} is negligible since the average center-to-center spacing between cells or boxes will not change appreciably if the boxes deflect independently in random directions or act together in a single direction. As the seismic contributions were determined to be negligible, the effect of this type of abnormal condition on the criticality calculations was not considered further.

9A.3.2.3 **Calculational Methods**

9A.3.2.3.1 Analytical Methods

The design method which insures that a subcritical condition is maintained in the spent fuel storage racks is similar to the NRC-approved Westinghouse Owners Group (WOG) methodology, which is described in References 9 and 10. The analysis of the Surry spent fuel pool incorporated the following exceptions to the WOG methodology:

1. The WOG methodology assumed a nominal UO_2 density of 95.0% T.D. The Surry spent fuel pool analysis used a nominal UO_2 density of 95.5% T.D., based on actual as-built fuel assembly uranium-loading information for Surry

2. The WOG methodology assumed a UO_2 density variation of ±2.0% T.D. about the nominal reference density, and variation in the fuel pellet dishing fraction from 0% to twice the nominal pellet dishing fraction. The analysis for the Surry spent fuel pool assumed a ±1.5% T.D. variation in fuel pellet density, based on the fuel manufacturing specifications and as-built fuel assembly uranium-loading information.
3. The WOG methodology used 227 group ENDF/B-V cross sections. These cross sections have not been made available to Virginia Power by Oak Ridge National Laboratory. Therefore, the Surry spent fuel pool analysis used 238 group ENDF/B-V cross sections, which have been extensively benchmarked.
4. The Surry spent fuel pool analysis does not require any boron credit. Therefore, the WOG boron credit methodology is not applicable.
5. The WOG methodology uses a nominal temperature of 68°F and pressure of 14.7 psia. In the analysis for the Surry spent fuel pool, the nominal temperature was set to the most conservative value over the typical temperature range, which was determined to be 170°F. The nominal pressure was set to 28 psia to account for the effects of the spent fuel pool water depth.
6. Although the NRC-approved WOG methodology does not require consideration of the effect of the axial burnup distribution on fuel assembly reactivity, an axial burnup gradient reactivity bias was applied to the evaluation of the Surry spent fuel pool.
7. The WOG methodology includes B^{10} self-shielding bias for spent fuel pools with poison panels. The Surry spent fuel storage cells do not include any poison panels, so this bias is not necessary in the Surry analysis. In addition, the Surry reactivity and tolerance calculations do not account for any poison panels

The design method uses the BONAMI and NITAWL-II codes for cross section generation, and the KENO-V.a code for reactivity determination. The 238-group ENDF/B-V cross section library is the starting point for all cross sections used for the KENO-V.a calculations. BONAMI (Reference 4) performs a resonance self-shielding calculation based on the Bondarenko method, and produces problem dependent master data sets. NITAWL-II (Reference 5) performs problem dependent resonance shielding calculations by applying the Nordheim Integral Treatment. These multigroup cross section sets are then used as input to KENO-V.a, which is a three dimensional Monte Carlo theory program designed for reactivity calculations (Reference 8). KENO-V.a calculations are always performed with sufficient neutron histories to assure convergence.

Two different KENO-V.a models were used. One model represented an infinitely reflected single spent fuel storage cell, while the other model represented the entire Surry spent fuel storage pool. The storage cells in the full pool model are placed in arrays to model each fuel storage rack, which are placed in their appropriate fuel pool location along with the fuel transfer canal and concrete buttress. This configuration is then surrounded with the stainless steel liner and concrete walls and floor.

9A.3.2.3.2 Benchmark Calculations

In order to establish the accuracy of the computer codes used for this analysis, the KENO-V.a code and cross sections were compared to critical experiment data for fuel assemblies similar to those for which the Surry spent fuel racks were designed. These benchmarking data, which represents fifty-nine validation criticality test cases for UO_2 lattices, are sufficiently diverse to establish that the method bias and uncertainty will apply to the rack conditions covered by this analysis.

The benchmark critical experiments resulted in an average KENO-V.a k_{eff} of 0.99643, which compared to a critical k_{eff} of 1.0 gives a KENO-V.a model bias of 0.00357 Δk. On a 95% confidence level, there is a 95% probability that the uncertainty in reactivity due to the method is not greater than 0.00099 Δk.

Reactivity equivalencing and tolerance calculations were performed using the Westinghouse PHOENIX-P code. The benchmarking performed for the WOG methodology covers a range of lattice parameters and configurations encompassing present fuel storage configurations. Based on the NRC acceptance of PHOENIX-P and their approval of the WOG methodology described in Reference 9, further benchmarking was not performed for the Surry spent fuel pool analysis.

9A.3.2.4 **Analysis Results**

9A.3.2.4.1 Normal Configurations

KENO-V.a calculations were performed for the reference configuration using both the infinitely reflected single storage cell model and the full spent fuel pool model. It was determined that use of the single storage cell KENO-V.a model is slightly conservative for this analysis. The k_{eff} for the single storage cell model was. 0.92950.

The effects of possible variations in material characteristics and mechanical/construction dimensions on spent fuel pool reactivity were performed using Westinghouse's PHOENIX-P code. These calculations included the effects of:

1. Fuel enrichment tolerance.
2. Variation in UO_2 density.
3. Variation of the fuel pellet dishing fraction.
4. Tolerance about the nominal reference storage cell inner dimension.
5. Tolerance about the nominal storage cell center-to-center pitch.
6. Tolerance about the nominal reference storage cell material thickness.
7. Asymmetric positioning of fuel assemblies within the storage cells.

The impact of each of these factors on the calculated k_{eff} is given in Table 9A-3. The total uncertainty associated with material characteristics, mechanical construction, and the KENO-V.a methodology is determined by statistically combining the effects of these tolerances with the calculational uncertainty. The combined uncertainty is 0.01064, as shown in Table 9A-3.

The 95/95 k_{eff} for the Surry spent fuel storage racks was then derived from:

$k_{eff} = k_{nominal} + B_{method} + B_{temp} + B_{uncert}$

where:

$k_{nominal}$ = nominal conditions KENO-V.a k_{eff} (0.92950)

B_{method} = method bias determined from benchmark critical comparisons (0.00357)

B_{temp} = temperature bias (0.0)

B_{uncert} = uncertainty associated with material characteristics, mechanical construction, and KENO-V.a method (0.01064)

The resulting spent fuel pool k_{eff} is 0.94371.

9A.3.2.4.2 Abnormal Configurations

As discussed in Section 9A.3.2.2, one type of accident which can cause reactivity to increase in the spent fuel rack involves an increase or decrease in the spent fuel pool water temperature and density. The normal conditions analysis, which covered a normal temperature range from 50°F to 170°F, showed that k_{eff} is less than 0.95 with no boron present in the spent fuel pool. The double contingency principle of ANSI/ANS 8.1-1983 states that protection against a criticality accident does not require assumption of two unlikely, independent, concurrent events. The presence of soluble boron in the spent fuel pool storage water can therefore be assumed as a realistic initial condition, since the lack of boron in the pool would be the result of a second unlikely event (i.e., a boron dilution accident). It was determined that an increase in pool temperature from 170°F to 246.4°F, the temperature at which boiling would be expected to occur in the spent fuel pool, increases the spent fuel pool k_{eff} less than the worth of the boron normally present in the spent fuel pool. Therefore, the 0.95 k_{eff} limit will be met for a pool water temperature increase.

The second type of accident which can affect reactivity in the spent fuel pool involves the placement of a fuel assembly into a position for which any restrictions on location, enrichment, or burnup are not satisfied. The normal conditions evaluation assumed a spent fuel storage rack configuration containing all fresh fuel at the maximum permissible proposed Surry fuel enrichment, with no restrictions on assembly location. Therefore, fuel assembly misplacement under normal handling conditions is already bounded by the reference non-accident analysis.

Two additional fuel assembly misplacement accidents that were considered were determined to have no impact on reactivity. These accidents include a fuel assembly drop on top of a rack, and a fuel assembly drop between rack modules or between a rack module and the spent fuel pool wall. A fuel assembly which drops onto the top of the fuel racks will impact the flared tops of the fuel storage rack cells. While minor deformation of the flared tops may occur, the close proximity of the upper grid structure to the impact point will preclude significant lateral displacement of the storage cells, so the rack structure pertinent for criticality control is not excessively deformed by the fuel assembly. KENO-V.a sensitivity cases confirmed that a dropped assembly which comes to rest either horizontally or vertically on top of the rack has sufficient water separating it from the active fuel height of stored assemblies to preclude neutron interaction, so the effect on k_{eff} is negligible. For the second scenario, PHOENIX-P sensitivity cases showed that placing an assembly outside of the racks per the second accident scenario is bounded by the normal conditions analysis.

To ensure that the spent fuel pool k_{eff} remains less than or equal to 0.95 during a fuel storage cask handling accident, limitations must be placed on the initial enrichment and burnup of the fuel assemblies which may be stored in Region 1 of the Surry spent fuel pool.

To evaluate the impact of a storage cask handling accident on spent fuel pool criticality, the deformed fuel and the associated storage racks were assumed to be at the optimum pitch. KENO-V.a calculations were run to determine the maximum fresh fuel enrichment that meets the 0.95 k_{eff} limit, including all applicable uncertainties and tolerances. The same methodology employed for the 95/95 k_{eff} calculations for the normal configurations was used for these calculations. It was determined that any fuel with an initial U^{235} enrichment less or equal to 1.9 weight percent may be loaded into Region 1 of the Surry spent fuel pool.

To allow the loading of fuel with higher initial enrichments in Region 1 of the Surry spent fuel pool, credit must be taken for the fuel burnup. A series of reactivity calculations were performed using the PHOENIX-P code and following the methodology outlined in Reference 9 to identify fuel assembly initial enrichment-discharge burnup pairs, which all yield equivalent k_{eff} values for the Surry spent fuel storage racks. These burnup credit cases incorporated the following conservatisms and uncertainties:

1. Fuel depletions were performed at a conservatively high boron concentration to enhance the predicted buildup of plutonium.
2. Burnup credit cases assumed no xenon.
3. A PHOENIX-P code uncertainty was applied.
4. An axial burnup gradient reactivity bias was applied.
5. A reactivity bias was applied to account for changes in optimum pitch due to burnup and enrichment changes.

6. An uncertainty was also applied to assembly burnup to reflect uncertainties in burnup measurements.

The results of these burnup credit reactivity equivalencing calculations were used to define a curve of assembly burnup versus initial fuel enrichment, which is included in the Surry Technical Specifications as Figure 5.4-1. Use of fuel with a burnup and enrichment combination which falls above this curve in Region 1 of the Surry spent fuel pool ensures that the spent fuel pool keff remains less than or equal to 0.95 during a fuel storage handling accident.

9A REFERENCES

1. Letter from C. M. Stallings (Vepco) to E. G. Case (NRC), *Request for Technical Specification Change No. 53, Surry Power Station Units 1 and 2*, dated May 1977
2. Letter from J. D. Neighbors (NRC) to W. L. Stewart (Virginia Power), Approval of Technical Specifications 84 and 85, dated March 1983.
3. Nuclear Energy Services, Inc., *Nuclear Design Analysis Report For The Surry Nuclear Power Station High Density Fuel Storage Racks*, NES-81A0494, dated March 1980.
4. N. M. Greene, *BONAMI: Resonance Self-Shielding by the Bondarenko Method,* ORNL/NUREG/CSD-2/V2/R5, Section F1, March 1997.
5. N. M. Greene, et al., *NITAWL-II: SCALE System Module for Performing Resonance Shielding and Working Library Production,* ORNL/NUREG/CSD-2/V2/R5, Section F2, March 1997.
6. Report No. 320-3254, ISB/GGC3, IBM Scientific Center, Palo Alto, California.
7. R. J. Weader, NES 81A0260, *Criticality Analysis of the Atcor Vendenburgh Cask*, February 1975.
8. L. M. Petrie and N. F. Landers, *KENO-V.a: An Improved Monte Carlo Criticality Program with Supergrouping,* ORNL/NUREG/CSD-2/V1/R2, Section F11, March 1997.
9. W. D. Newmyer, *Westinghouse Spent Fuel Rack Criticality Analysis Methodology,* WCAP-14416-P, June 1995.
10. Letter from T. E. Collins (NRC) to Tom Greene (Westinghouse), *Acceptance for Referencing of Licensing Topical Report WCAP-14416-P, "*Westinghouse Spent Fuel Rack Criticality Analysis Methodology*",* TAC No. M93254, October 25, 1996.

Table 9A-1
COMBINED STRESS SUMMARY (FUEL RACKS)

Load Combination	Element No./Type	Combined Stress (ksi) [a] Calculated	Allowable	Combined [b] Stress Ratio
D + L	74/Beam	1.70	18.5	-
	158/Beam	1.78	18.5	-
	48/Plate	1.17	16.8	-
D + I.L.	77/Beam	15.52	18.5	-
	48/Plate	1.24	6.8	-
D + L + E (fully loaded rack)	2/Beam	5.56	-	0.32
	74/Beam	6.85	-	0.54
	158/Beam	5.18	-	0.36
	164/Beam	4.97	-	0.29
	48/Plate	9.17	16.8	-
D + L + E' (fully loaded rack)	2/Beam	9.66	-	0.35
	74/Beam	10.51	-	0.59
	158/Beam	7.67	-	0.37
	164/Beam	8.51	-	0.32
	48/Plate	16.22	26.9	-
D + U.L.	70/154/Beams	16.93	29.6	-
	53/Plate	0.85	26.9	-

a. Maximum total stress $P/A + M_2C_3 + M_3C_2$ for beams. Maximum von Mises for plates. Allowable stresses are flexural for beams and tensile for plates.

b. Combined axial compression plus bending stress requirement for AISC Specification Section.

Table 9A-2
SUMMARY OF STRESSES (ksi)

Location	Hydrostatic + Dead + Live	Hydrostatic + Dead + Live + OBE	Hydrostatic + Dead + Live + SSE	Hydrostatic + Dead + High-Density Racks
4A	21.4	27.8	34.1	-
4B	21.4	26.7	32.0	-
4C	20.7	25.1	29.5	-
4E	18.1	23.6	29.1	-
3A	20.9	27.1	33.3	17.7
3B	19.8	24.8	29.8	14.9
3D	19.8	25.2	30.7	17.5
3E	21.4	27.8	34.1	20.9
2A	19.0	-	-	-
2E	21.7	-	-	20.9
Allowable stress	f_s 21.8	4/3 f_s 29.0	0.9 f_y 39.0	f_s 21.8

Allowable stress based on minimum coupon strength sample.

$f_y = 43.6$ ksi $f_s = 0.5\ f_y$

Note: Columns 1, 2, and 3 are the original loads in the fuel building structure, and column 4 shows the change with the addition of the high-density spent-fuel racks.

Table 9A-3
RESULTS OF TOLERANCE CALCULATIONS
FOR NORMAL SPENT FUEL RACK CONFIGURATION

Tolerance	Δk
Enrichment (+0.05 wt.%)	0.00247
Density (+1.5% TD)	0.00284
Dishing Fraction (0%)	0.00234
Cell Pitch (-1/4 in.)	0.00823
Cell Wall Thickness (-0.005 in.)	0.00196
Cell i.d. (-1/16 in.)	0.00005
Assembly Position	0.00439
Calculational Uncertainty	0.00130
Methodology Uncertainty	0.00099
Total Uncertainty (B_{uncert})	0.01064

The total uncertainty (B_{uncert}) was determined
by statistically summing each uncertainty component.

$$B_{uncert} = \sqrt{\sum_i Unc_i^2}$$

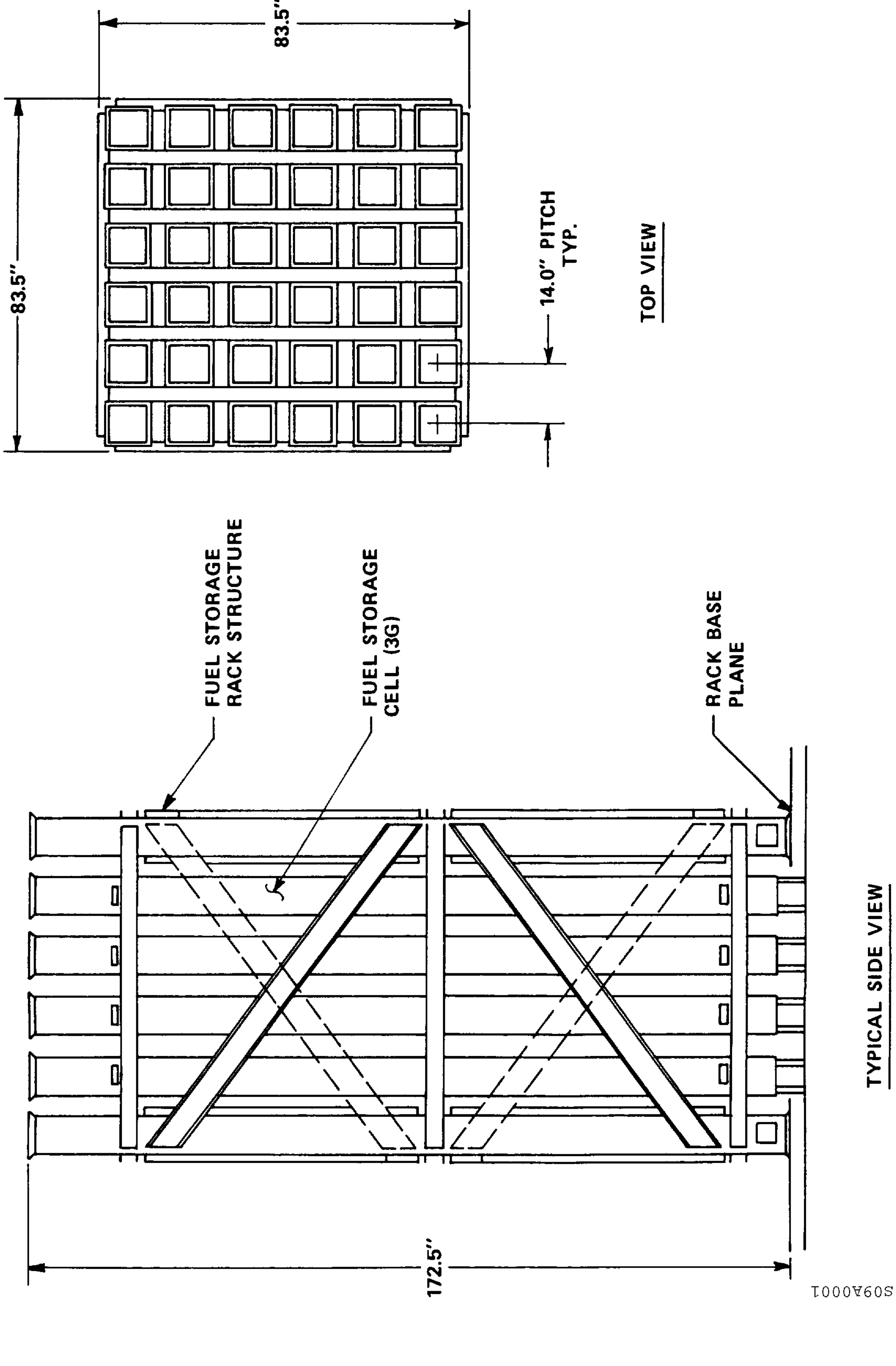


Figure 9A-1
SPENT FUEL RACKS

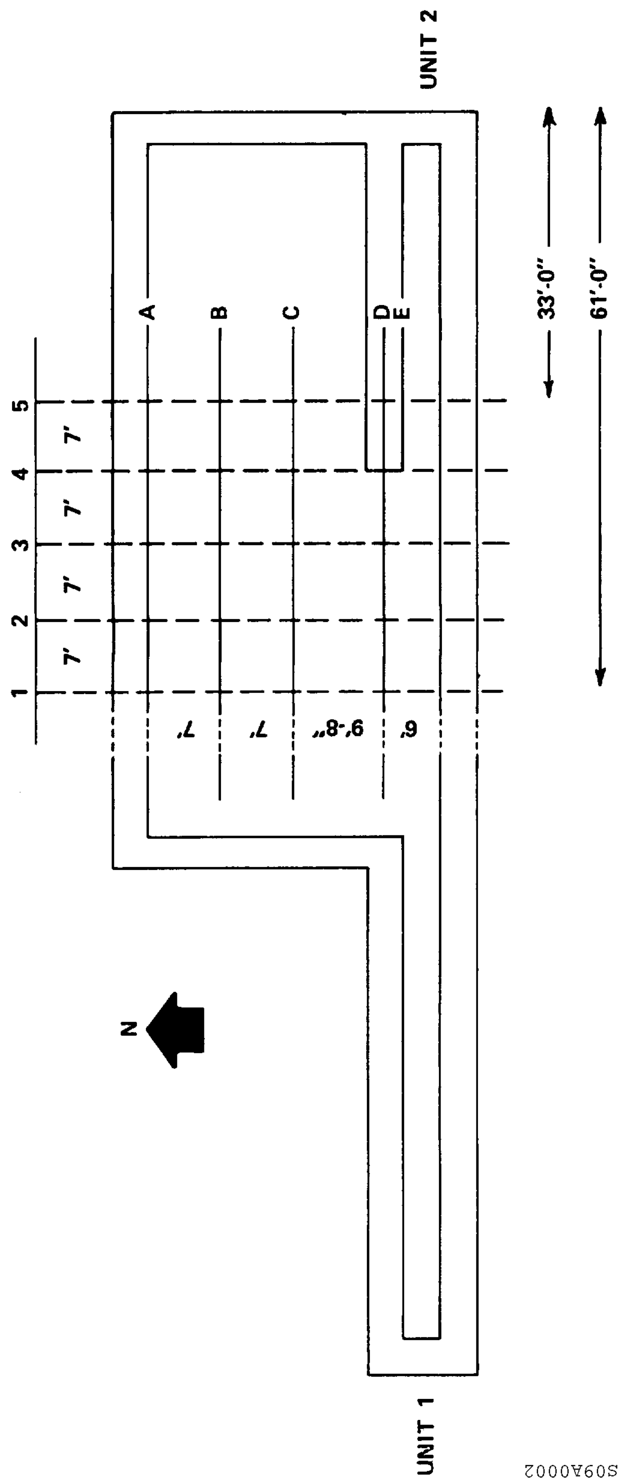


Figure 9A-2
FUEL POOL STRESS POINT LOCATIONS FOR TABLE 9A-2

Intentionally Blank

Appendix 9B
Movement of Heavy Loads

Intentionally Blank

APPENDIX 9B MOVEMENT OF HEAVY LOADS

9B.1 HEAVY LOADS OVER SPENT FUEL

This section describes the movement of heavy loads over the reactor core or the spent fuel storage pool. A fuel assembly is not defined as a heavy load, and the movement of fuel assemblies is not controlled under NUREG-0612.

NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants,* (Reference 1) defines a heavy load as a load greater than the combined weight of a single fuel assembly and its handling tool. A fuel assembly weighs approximately 1470 lb and the spent fuel handling tool weighs approximately 350 lb, therefore, this heavy load definition is:

Fuel Assembly	1470
Handling Tool	+ 350
	1820

During refueling operations, a heavy load is defined as 110% of the weight of a fuel assembly (not including the fuel handling tool). This heavy load weight definition is:

Fuel Assembly	1470	
100%		x 1.1
	1617	

Using a single value that bounds both of these definitions, a heavy load subject to NUREG-0612 controls is a load greater than 1600 lb.

9B.1.1 Reactor Vessel Head

The reactor vessel head is lifted by the containment polar crane. Its movement path includes a vertical lift from the reactor vessel, a horizontal movement, and a vertical descent to the head storage area in the basement. The head is returned to the reactor vessel using the reverse sequence. The containment equipment locations can be seen on Reference Drawings 1 and 3. The size and shape of the head are shown on Reference Drawing 3. The weight of the head and lifting device is provided in Table 9B.2-1.

A reactor vessel (RV) head drop analysis based on the guidance and acceptance criteria in NEI 08-05, *Industry Initiative on Control of Heavy Loads* (Reference 17), has been performed to establish limits on load height, load weight, and medium present under the load. Procedures are used to control the lift and replacement of the reactor vessel head, which ensure the limits established in the RV head drop analysis are maintained.

9B.1.2 Reactor Vessel Upper Internals

The reactor vessel upper internals are removed from the reactor vessel by the containment polar crane and are placed in the upper internals lifting rig storage stand. This involves a vertical lift from the reactor vessel, a horizontal movement, and a vertical descent to the storage stand. The upper internals are returned to the vessel using the reverse sequence. The weight of the upper internals and lifting rig is provided in Table 9B.2-1. The upper internals are described in Chapter 3.

9B.1.3 Reactor Irradiation Sample Shipping Casks

In accordance with the reactor vessel radiation surveillance program, reactor irradiation sample assemblies are removed from the reactor vessel at intervals as specified in Section 4.1.7. The sample assemblies are removed from the reactor vessel and transferred to the spent fuel storage pool in a sample basket. The samples are then shipped to a contractor laboratory in a shipping cask. Several shipping cask designs can be used, and these casks weigh from approximately 8000 lb to approximately 23,000 lb. These casks may be loaded without placing them in, or moving them over, the spent fuel storage pool. If a cask is loaded in, or moved over, the spent fuel storage pool, an evaluation must be performed to ensure that cask drop analyses remain bounding.

9B.1.4 Fuel Transfer Canal Door

At the end of each fuel transfer canal in the spent fuel storage pool, a door is used to isolate the canal, if needed. These doors are marked “Gate” on Reference Drawing 4. The dry weight of the transfer canal door is approximately 3200 lb. Prior to refueling, the transfer canal door is removed from the canal and moved to a storage position on the side of the spent fuel storage pool. The door is also removed on a periodic basis to perform seal maintenance. Administrative controls are imposed for moving the transfer canal door over fuel assemblies. The controls limit the lift height of the door and prohibit spider-mounted insert components in fuel assemblies in the load path while the door is being moved. These restrictions ensure that fuel assemblies will not be impacted if the transfer canal door were to drop during movement.

9B.1.5 Spent Fuel Casks

Spent fuel cask drop evaluations have been conducted in support of loading and unloading spent fuel casks in the fuel building. The results of these evaluations, and the request for a license amendment to permit movement of spent fuel casks in the fuel building are provided in References 2 and 3. As part of these evaluations, two cask impact pads have been installed in the cask loading area of the spent fuel storage pool. These pads are designed to protect the floor of the spent fuel storage pool from damage in the event a spent fuel cask is dropped from the fuel cask trolley. Fuel assemblies stored in the first three rows of storage racks adjacent to the cask loading area must have decayed at least 150 days after discharge from the reactor, and must also meet the requirements for burnup and enrichment. These requirements ensure that the radiological consequences are bounded by the consequences for a fuel handling accident, and prevent fuel criticality in the event of a cask drop and tip onto the storage racks. A description of the fuel cask trolley and its operation is provided in Section 9.12.4.13.

License amendments permit the movement of spent fuel casks into the fuel building (Reference 4). Cask drop evaluations of the TN-2100 and GNS-5 casks are included in the license amendments. The license amendments concluded the following:

1. The spent fuel storage pool will not be damaged by a worst-case cask drop, and even if the pool liner should be punctured, no significant leakage is expected since the pool walls would not experience through-cracking.
2. Fuel assemblies in the spent fuel storage pool remain sub-critical if storage racks are damaged by a cask drop and tip, and the radiological consequences are well within the guidelines of 10 CFR 100.
3. Damage to spent fuel storage pool piping would not cause the pool to drain. It also confirmed that there are no safe shutdown systems under the travel path of the fuel building trolley.

Subsequent safety evaluations conclude that the cask drop evaluations are bounding for the CASTOR V/21, CASTOR X/33, MC-10, NAC-I/28, TN-32, and NUHOMS OS187H casks. Cask weights, including the lifting device, are from approximately 157,000 lb to approximately 240,000 lb. The cask lifting device weighs approximately 7000 lb, therefore, its movement over the spent fuel storage pool is also controlled as a heavy load. The NUHOMS EOS-TC125 transfer cask was evaluated under the same scenarios as previous casks (Reference 5). It was concluded that the consequences of dropping the EOS-TC125 are bounded by the previously evaluated casks. The EOS-TC125 is described in the NUHOMS EOS System Updated Final Safety Analysis Report.

The drop of cask lids into the spent fuel storage pool has also been evaluated. After fuel assemblies are loaded into a cask, the lid is moved over the spent fuel storage pool and placed onto the cask. Conversely, after a loaded cask is placed in the spent fuel storage pool for unloading, the lid is removed from the cask and carried over the pool. Both of these operations take place over the cask loading area of the spent fuel storage pool. Lid weights vary with spent fuel cask design, so the analysis used the heaviest known lid weight of approximately 14,000 lb. If a lid is dropped while it is over the cask, damage to the fuel assemblies in the cask is bounded by the cask drop consequences in Reference 2. If the lid drops edgewise onto a cask impact pad, it does not perforate the top plate of the pad, and the spent fuel storage pool liner and floor are not damaged. If the lid drifts horizontally through the water and strikes the storage racks adjacent to the cask loading area, the damage to storage racks and fuel assemblies is bounded by the analyses in Reference 2. If the lid drifts horizontally and strikes a wall of the spent fuel storage pool, the structural response is also bounded by the cask drop analyses.

Cask and lid handling over the spent fuel storage pool is controlled by written procedures which limit cask and lid lift heights and cask orientation consistent with the cask and lid drop analyses.

9B.1 REFERENCES

1. NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants,* U. S. Nuclear Regulatory Commission, July 1980.
2. Letter from R. H. Leasburg, Vepco, to H. R. Denton, NRC, Subject: *Amendment to Operating Licenses DRP-32 and DRP-37, Surry Power Station Unit Nos. 1 and 2. Proposed Technical Specification Changes,* dated September 23, 1982 (Serial No. 543).
3. Letter from R. H. Leasburg, Vepco, to H. R. Denton, NRC, Subject: *Supplemental Information for Proposed Operating License Amendment,* dated January 17, 1983 (Serial No. 543A).
4. Letter from J. D. Neighbors, NRC to W. L. Stewart, Vepco, Subject: *Amendment No. 84 to Operating License DPR-32 and Amendment No. 85 to Operating License DPR-37, Surry Power Station Units 1 and 2, Technical Specification Changes*, dated March 4, 1983 (Serial No. 131).
5. Calculation CE-14247.01-NMB-194-FB, *Fuel Cask Drop Analysis for the NUHOMS EOS TC125 Cask System*, January 2021

9B.2 HEAVY LOADS OVER SAFE-SHUTDOWN EQUIPMENT

9B.2.1 Introduction/Background

On December 22, 1980, NRC issued a generic letter (unnumbered) which was supplemented February 3, 1981 (Generic Letter 81-07) regarding NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants* (Reference 1) NUREG-0612 presents an overall philosophy that provides a defense-in-depth approach for controlling the handling of heavy loads. The approach is directed toward the safe handling of lifted loads.

The NRC requested that Surry Power Station implement certain interim actions and provide information related to heavy loads. Submittals were requested in two parts; a 6-month response (Phase I) and a 9-month response (Phase II). Phase I responses were to address Section 5.1.1 of NUREG-0612 which covers the following areas:

Guideline 1 - Safe Load Paths

Guideline 2 - Load Handling Procedures

Guideline 3 - Crane Operator Training

Guideline 4 - Special Lifting Devices

Guideline 5 - Lifting Devices (not specially designed)

Guideline 6 - Cranes (inspection, testing, and maintenance)

Guideline 7 - Crane Design

In addition, the Phase I Report was to identify all load handling systems within the plant that are capable of carrying a heavy load. These load handling systems were divided into two groups:

Group I: Heavy load handling systems from which a load drop may result in damage to any system required for plant shutdown or decay heat removal, taking no credit for interlocks, technical specifications, operating procedures, detailed structural analysis or system redundancy.

Group II: Heavy load handling systems excluded from Group I based on determination by inspection that there is sufficient physical separation between any load impact point and any system needed for plant shutdown or decay heat removal.

Phase II responses were to address Sections 5.1.2 thru 5.1.6 of NUREG-0612 which cover the need for electrical interlocks/mechanical stops, or alternatively, single-failure-proof cranes or load drop analyses in the spent fuel pool area, containment building, and other areas of the plant, and the specific guidelines for single-failure-proof handling systems.

On June 28, 1985, NRC issued Generic Letter 85-11 (Reference 2) which rescinded Phase II. It concluded that Phase I implementation had provided sufficient protection such that the risk associated with potential heavy load drops was acceptably small and no further action was required beyond that identified during Phase I. The NRC Safety Evaluation and their consultant's Technical Evaluation Report (TER) (Reference 3) for the six month response (Phase I) were issued in 1984 with program clarifications via Generic Letter 85-11.

The Surry Technical Specifications (TS) also prohibit heavy loads from being moved over spent fuel. Detailed discussion of how the heavy loads program implements this requirement is presented in Section 9B.2.5.

The following sections summarize the commitments that were made by Virginia Power as part of the Phase I submittal with regard to compliance with Section 5.1.1 of NUREG-0612. Any errors made in the Phase I report are noted and corrected. Additions to the heavy loads program that have been incorporated since the issuance of the Phase I report are also included. Program deletions are detailed within the References. Each of the seven guidelines of Section 5.1.1 of NUREG-0612 along with the definition of a heavy load subject to NUREG-0612 and the list of the handling systems that are capable of moving heavy loads subject to NUREG-0612 are discussed in detail below.

On September 14, 2007, the nuclear industry's Nuclear Strategic Issues Advisory Committee approved an industry initiative to address NRC staff concerns regarding the interpretation and implementation of regulatory guidance associated with heavy load lifts (Reference 16). In response to the industry initiative, reliance on a reactor vessel head drop analysis was included into the safety basis for the control of heavy loads at Surry Power Station. Further discussion on this is provided in Section 9B.1.1.

On September 5, 2008, the NRC issued a Safety Evaluation Report for the methods presented in NEI 08-05, Industry Initiative on Control of Heavy Loads (Reference 17), concluding that the guidelines contained in NEI 08-05, Revision 0, are acceptable for implementation of the industry initiative on control of heavy loads. NEI 08-05 was also endorsed by the NRC in RIS 2008-28 (Reference 19).

Heavy load lifts for the Emergency Service Water Pumps and associated equipment are considered lifts subject to the requirements of NUREG-0612. Alternate methodologies for evaluating these heavy load lifts have been used that consider Risk Management Actions in accordance with NEI 08-05 coupled with consideration of the lifts as configuration management activities with administrative controls established in accordance with 10CFR50.65(a)(4) to establish the safety basis.

Previous controls implemented by station commitments to NUREG-0612 Phase I Guidelines and the use of the Risk Management Actions in accordance with NEI 08-05 make the risk of a load drop and adverse consequences very unlikely. The evaluation of the heavy load lifts for the Emergency Service Water Pumps and their associated components evaluates the NUREG-0612 Criterion IV consequence considerations within the Maintenance Rule 10CFR50.65(a)(4) program through existing procedural guidance and requirements.

9B.2.2 Heavy Loads

NUREG-0612 defines a heavy load as any load that weighs more than the combined weight of a single spent fuel assembly and its associated handling tool. Surry's Phase I report established this load as 2000 pounds; however, a lower weight of 1600 pounds has been adopted in recognition of the more restrictive definition given in Technical Specifications (TS). A load is subject to NUREG-0612 if it exceeds 1600 pounds and is carried over irradiated fuel, safe shutdown equipment or decay heat removal equipment.

9B.2.3 Overhead Heavy Load Handling Systems

The following load handling systems are subject to compliance with NUREG-0612:

1. Reactor Containment Polar Cranes
2. Reactor Containment Annulus Monorail
3. Containment Jib Cranes
4. Fuel Building Motor Driven Platform
5. Auxiliary Building 10-ton Monorail (27' level)
6. Auxiliary Building 5-ton Monorail (13' level)

7. RHR Pump Motor Lifting Lugs
8. Spent Fuel Crane

The RHR pump motor lifting lugs were plant modifications completed after the TER was issued. A jib crane in each containment was mentioned in the TER; this crane is included in heavy loads procedures. The TER included other handling systems as originally being subject to NUREG-0612 that are no longer included in the heavy loads program. Reference 5 discusses those handling systems and the justification for their elimination. A listing of heavy loads per handling system is tabulated in Table 9B.2-1.

9B.2.4 NUREG-0612, Section 5.1.1 Guidelines

9B.2.4.1 **Safe Load Paths**

Safe load paths for the movement of heavy loads have been developed which follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. Either a sketch or description of the load paths have been incorporated into lifting procedures. Safe load paths do not require specific lift height restrictions other than to keep the load as low as practical while maintaining adequate vertical clearances over obstructions in the load path. Maximum lift height limits and load drop studies were part of the Phase II requirements that were rescinded by the NRC (Reference 2).

Safe load paths are discussed during the pre-job briefing and loads are guided along the safe load path during the lift operation. Also, restricted areas are used in the containment structure for several heavy loads such as concrete floor plugs that are routinely shuffled to several laydown areas during an outage. These restricted areas include: over the reactor, steam generators, and main steam/feedwater riser area. Drawings are available which indicate operating floor capacities that are used during outages to control laydown space in conjunction with the Heavy Loads Program.

Safe load path sketches are used to control the movement of the fuel transfer canal gates in the fuel pool.

9B.2.4.2 **Load Handling Procedures**

Station maintenance procedures have been developed for performing heavy load lift operations. The procedures identify the following items:

1. Equipment identification.
2. Required equipment inspections and acceptance criteria prior to performing lift and movement operations.
3. Approved safe load paths.
4. Safety precautions and limitations.

5. Special tools, rigging hardware, and equipment required for the heavy load lift.
6. Rigging arrangement for the load.
7. Adequate job steps and proper sequence for handling the load.

9B.2.4.3 Crane Operators Training

NUREG-0612 requires that crane operators be trained, qualified and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, *Overhead and Gantry Cranes* (Reference 6). Station administrative procedures ensure that crane operators are qualified.

9B.2.4.4 Special Lifting Devices

As indicated in the TER (Reference 3):

> [The following special lifting devices in use at Surry Units 1 and 2 were identified as being subject to compliance with the criteria of NUREG-0612 and ANSI N14.6-1978:
>
> a. reactor vessel head lifting device (RVHLD)
>
> b. internals lifting rig (ILR)
>
> c. reactor coolant pump motor sling (RCPLS)
>
> The original manufacturer of these devices (Westinghouse) performed a detailed comparison of the ANSI criteria and records that document the original design, manufacture, inspection, and testing of the special lifting devices. Results of this review indicate that the devices meet the intent of the ANSI Standard for design, fabrication, and quality assurance, but are not in strict compliance with criteria for maintenance, acceptance testing, or continuing compliance.
>
> Design, fabrication, and quality assurance requirements for these devices were defined on detailed manufacturing drawings and purchase orders. A stress report was prepared, applying the design margin criteria of 3 (yield) and 5 (ultimate) on stress, and results indicate that all devices possess acceptable limits for tensile and shear stress with the following exceptions for the internals lifting rig: (1) tensile and shear stresses in the side plates; (2) thread shear stresses in the leg adaptor; and (3) the tensile stress at the minimum section of the engaging screw. For these exceptions, it was noted that the actual margin is slightly less than the specified criterion of 3 on yield stress, whereas all components satisfy the criterion of 5 on ultimate stress. It is therefore concluded that the existing design is adequate.
>
> In addition, manufacturing surveillance of hold points, procedure review, and personnel qualification which adequately meet ANSI requirements were also provided by the manufacturer during the fabrication and assembly of these devices. Load tests to 100% have been performed for each of the devices, although documentation is

available for the reactor vessel head lifting device only. Although load tests in excess of 100% have not been performed, it is felt that such tests are not necessary since proof of workmanship can be documented through use of existing load tests, adequate design margins, and documentation of procedures that were actually used during the manufacture of these devices. Maintenance procedures require visual examinations of the special lifting devices prior to each refueling and each containment maintenance period if use of the device is anticipated. These visual inspections include inspections of all critical welds and bolted joints or connections, and results are appropriately documented. In addition, a load cell is used during lifts by the reactor vessel head lifting device and the internals lifting rig to provide continuous monitoring to prevent overstressing of either device. To ensure an even higher level of confidence and acceptability of these devices, a nondestructive examination (NDE) program is established. This program includes inspection and NDE of all critical welds and critical parts of the lifting devices over the in-service inspection period of 10 years.]

Five additional special lifting devices have been identified that were not included in the TER:

8. Spent filter cask spreader beam
9. Spent fuel cask lifting yoke
10. Long cask lid lifting tool
11. Short cask lid lifting tool
12. Alternate lift rig for the SFP transfer canal gates.

These lifting devices have been included in station administrative procedures as special lifting devices and will be visually inspected prior to use and immediately after lifting the load. These devices will also be inspected under the 10-year Inservice Inspection Program using NDE methods.

The Reactor Vessel Head Stud Racks have been identified for inclusion under the guidelines of NUREG-0612 at Surry. These special lifting devices were not previously mentioned in the TER nor were they included with the subsequent group of five, as listed above in (8) through (12):

13. Reactor vessel head stud racks

The stud racks are not, however, in strict compliance with ANSI N14.6-1978 for design, fabrication, quality assurance, maintenance and continuing compliance, as noted in the following exceptions:

1. Stud racks were fabricated without official design calculations. To reconstitute a design basis, an engineering evaluation was performed, following the design criteria of ANSI N14.6-1978. The stud racks were conservatively assumed to be fabricated out of carbon steel materials, with strength properties at least comparable to that of ASTM A 36.
2. Stud racks were fabricated without fabrication or quality assurance records. Each of these stud racks has received a post-modification load test to 150% of their rated load capacities. A visual inspection was performed to further assess the quality of construction. Following the modifications, baseline nondestructive examinations were performed on all critical welds and critical parts to provide documented evidence of quality construction.
3. Annual testing per ANSI N14.6-1979 requires that either a 150% load test or dimensional, visual and nondestructive testing be performed. However, plant procedures presently require that each device, its welds, and any bolted joints be visually inspected prior to use and immediately after lifting the load. Therefore, the ANSI annual testing requirements have been waived in lieu of the prior-to-use visual inspections. To ensure more reliability and a higher level of confidence in the continuing compliance with ANSI N14.6-1978, Surry has instituted a nondestructive examination (NDE) program, which will provide for inspection and NDE of all critical welds and critical parts over a normal service interval of 10 years.

Based on the above, it is concluded that:

1. All tensile and shear stresses meet ANSI N14.6-1978 design criteria.
2. The ANSI requirements for design, fabrication, and quality assurance are generally in agreement with those used for these special lifting devices.
3. Although not in strict compliance with ANSI requirements, the load tests and nondestructive testing performed following assembly demonstrates the acceptability of these special lifting devices. Present station procedures meet the intent of ANSI N14.6-1978 regarding verification of continuing compliance.

In addition to the previously stated lifting devices, an intermediate lift ring, supplied by Framatome ANP, was installed during the installation of the SPS Unit 1 replacement closure head. Installation of the intermediate lift ring will utilize the existing lift rod lower clevises, along with the lift ring lower adapter blocks and lift pins, to attach the lift ring to the lifting rig assembly and the replacement closure head lifting lugs. The lift ring components were tested to 150% of the design load (i.e. 483,000 lb) for a minimum of ten (10) minutes, which meets the requirements of ANSI N14.6-1978. After this load-test, non-destructive and visual examinations were performed for surface indications, evidence of permanent deformation, and other nonconformances. Surfaces of the intermediate lift ring, adapter blocks, bolts, and lift pins were examined utilizing PT with acceptance criteria as established by NF5350 of the ASME Section III 1995 Edition with Addenda through 1996. Furthermore, post load-test visual examinations and dimensional checks for evidence of permanent deformation of the intermediate lift ring, adapter blocks, bolts, and lift pins were conducted. These examinations have demonstrated that the intermediate lift ring is acceptable for lifting operations (Reference 14).

9B.2.4.5 **Lifting Devices Not Specially Designed (Slings)**

A Surry station administrative procedure requires that slings used for heavy load lifts meet the requirements specified for slings in accordance with ANSI B30.9-1971 (Reference 7).

As stated in the TER (Reference 3), evaluation of sling capacity indicates that dynamic load constitutes a small percentage of the total load imposed on the slings; therefore, the sling's ratings can be safely expressed in terms of the maximum static load only.

9B.2.4.6 **Cranes (Inspection, Testing, and Maintenance)**

Cranes subject to NUREG-0612 requirements are inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, *Overhead and Gantry Cranes*, Chapter 11.2 of ANSI B30.11-1973, *Monorail Systems and Underhung Cranes*, or Chapters 16-1.2.1 and 16-1.2.3 of ANSI B30.16-1973, *Overhead Hoists* (References 6, 8 & 9), with the exception that tests and inspections may be performed prior to use for infrequently used cranes. Inspections and testing following modifications to the Unit 1 and Unit 2 containment polar cranes, that were required to increase the capacity of each main hoist from 125 tons to 140 tons for reactor head replacement, were done in accordance with ASME B30.2-2001, which is the latest version of the above referenced code. Only the modified portions of the uprated cranes were required to be tested and inspected. Prior to making a heavy load lift, an inspection of the crane is made in accordance with the above applicable standards.

9B.2.4.7 **Crane Design**

NUREG-0612, Section 5.1.1 (Reference 1), requires "the cranes be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, *Overhead and Gantry Cranes* (Reference 6) and of CMAA-70, *Specifications for Electric Overhead Traveling Cranes* (Reference 11). An alternate to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied."

CMAA-70 and ANSI B30.2-1976 apply to the reactor containment polar cranes and the spent fuel crane. These cranes were designed and fabricated in accordance with Electric Overhead Crane Specification #61 (Reference 12) prior to the issuance of the above reference standards. The Nine-Month Report (Reference 4) provided the results of a review of existing crane design with the recommendations contained in CMAA-70 and Chapter 2-1 of ANSI B30.2-1976. The NRC concluded in the TER that the design of the containment polar cranes and the spent fuel crane is consistent with the guidance in Section 5.1.1 of NUREG-0612 (Reference 1). Modifications to the Unit 1 and Unit 2 containment polar crane that were required to increase the capacity of each main hoist from 125 tons to 140 tons for reactor head replacement, were done in accordance with CMAA-70 and ASME B30.2-2001.

The reactor containment jib cranes were designed and fabricated in accordance with ANSI B30.16-1973 and ANSI B30.11-1973 (References 9 & 8). The reactor containment annulus monorails and 10-ton Auxiliary Building monorail systems, and motor-driven platform and hoists were designed in accordance with EOCI 61. It was concluded in the TER that these cranes and monorails meet the requirements of ANSI B30.11 and ANSI B30.16, and these load handling systems meet the intent of NUREG-0612.

The Auxiliary Building 13'-0” Elevation 5-ton hoist is designed to ANSI B30.16. Additionally, the hoist complies with ASME HST-4, *Performance Standard for Overhead Electric Wire Rope Hoists*. These two documents ensure the same level of design, testing and inspection as specified in the TER and compliance with NUREG-0612 requirements.

9B.2.5 Technical Specifications (TS)

Loads exceeding 110% of the weight of a fuel assembly are prohibited by TS from being lifted over spent fuel in the reactor vessel and the spent fuel pool with an explicit exception for the transfer canal door. The NUREG-0612 heavy loads program is used to implement the TS load restriction for loads greater than 1600 pounds; fuel handling procedures are used to implement the restriction which prevents handling more than one fuel assembly at a time over the reactor or spent fuel pool. Fuel handling is outside the scope of the NUREG-0612 program. NUREG-0612 heavy load procedures are used to control lifting of the transfer canal gate and additional exceptions associated with reactor vessel assembly and disassembly as discussed below.

- Movement of the spent fuel pool transfer canal doors are controlled by a NUREG-0612 heavy loads procedure which allows lifting over spent fuel in accordance with the TS.

- Movement of heavy loads over spent fuel in the reactor vessel are allowed for lifts that service the reactor such as the Unit 1 CRD missile shield, the cavity seal ring, the Unit 1 reactor head, the Unit 2 reactor head and head assembly upgrade package, and the reactor upper internals. These lifts are controlled by NUREG-0612 heavy loads procedures.

- Other loads exceeding 1600 pounds are not lifted over spent fuel in the reactor and spent fuel pool as required by TS. Movement of loads greater than 1600 pounds over spent fuel in the reactor and spent fuel pool are prohibited by NUREG-0612 heavy loads procedures which identify the reactor and the spent fuel storage area of the pool as restricted areas over which these loads shall not be lifted.

- The polar crane bottom block and hook are not considered as either a TS or NUREG-0612 heavy load because it is an integral part of the polar crane which is inspected and maintained by procedures in compliance with NUREG-0612 requirements. The unloaded failure of the lower block and hook is not considered a credible accident.

Lifting procedures do not prevent the unloaded block's movement over spent fuel whether it is in the core or being moved via the fuel handling system.

9B.1 REFERENCES

1. H. George, *Control of Heavy Loads at Nuclear Power Plants*, NUREG-0612, U. S. Nuclear Regulatory Commission, Washington, D. C., July 1980
2. Generic Letter 85-11, *Completion of Phase II of Control of Heavy Loads at Nuclear Power Plants, NUREG-0612*, June 28, 1985 (Serial #85-507)
3. Letter from S. A. Varga, NRC, to W. L. Stewart, VEPCO, *Control of Heavy Loads (Phase I)*, dated May 16, 1984, Docket Nos. 50-280 and 50-281, with enclosed *Safety Evaluation Report*, and *Technical Evaluation Report*, TER-C5506-395/396, dated April 23, 1984.
4. Letter from R. H. Leasburg, VEPCO, to H. R. Denton, NRC, *NUREG-0612, Control of Heavy Loads*, dated March 22, 1982, with enclosed *Nine Month Response* for both North Anna and Surry Power Stations.
5. Letter from J. P. O'Hanlon, VEPCO, to NRC, *Response to NRC Bulletin NRC 96-02*, dated May 13, 1996.
6. American National Standards Institute, ANSI B30.2-1976, *Overhead and Gantry Cranes*
7. American National Standards Institute, ANSI B30.9-1971, *Slings*
8. American National Standards Institute, ANSI B30.11-1973, *Monorail Systems and Underhung Cranes*
9. American National Standards Institute, ANSI B30.16-1973, *Overhead Hoists*
10. American National Standards Institute, ANSI N14.6-1978, *Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500kg) or More*
11. Crane Manufacturers Association of America, Inc., *Specifications for Electric Overhead Traveling Cranes*, CMAA-70, Pittsburgh, Pa., 1975
12. Electric Overhead Crane Institute, *Specifications for Electric Overhead Traveling Cranes*, EOCI-61, Pittsburgh, Pa.
13. American Society of Mechanical Engineers, ASME B30.2-2001, *Overhead and Gantry Cranes.*
14. Framatome ANP Document 23-5026339, *QA Data Package - Intermediate Lift Ring for SPS 1 RVCH.*
15. ASME HST-4, *Performance Standard for Overhead Electric Wire Rope Hoists*.
16. Letter from A. R. Pietrangelo, NEI, to J. E. Dyer, NRC, *Industry Initiative on Heavy Load Lifts*, September 14, 2007.

17. NEI 08-05, *Industry Initiative on Control of Heavy Loads*, July 2008. (Transmitted to NRC by Reference 18).

18. Letter from A. R. Pietrangelo, NEI, to E. J. Leeds, NRC, *Industry Initiative on Control of Heavy Loads*, July 28, 2008.

19. NRC Regulatory Issue Summary 2008-28, *Endorsement of Nuclear Energy Institute Guidance for Reactor Vessel Head Heavy Load Lifts*, December 1, 2008.

9B REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-1A	Machine Location: Reactor Containment, Elevation 47'- 4"
2.	11448-FM-1B	Machine Location: Reactor Containment, Elevation 18'- 4"
3.	11448-FM-1E	Machine Location: Reactor Containment; Sections “A-A”, “E-E”, & “Z-Z”
4.	11448-FM-9A	Arrangement: Fuel Building, Sheet 1
5.	11448-FM-9B	Arrangement: Fuel Building, Sheet 2, Unit 1

Table 9B.2-1
HEAVY LOADS[1]

Handling System		Heavy Load	Weight or Capacity (Tons)
Containment Polar Crane			140/15
	a.	(Unit 1) RV Head and Lifting Device[10]	131.2
		(Unit 2) RV Head, Lifting Device and CRD Missile Shield	132.6
	b.	RV Head Lifting Device (Tripod)[7]	4.0
	c.	RV Upper Internals and Lifting Rig	52.0
	d.	RV Upper Internals Lifting Rig[7]	6.5
	e.	Reactor Coolant Pump Motor and Sling	41.0
	f.	RCP Motor Sling[7]	1.1
	g.	RV Inner Seal Ring and Lifting Device	12.2
	h.	(Unit 1) CRDM Missile Shield	36.5
	i.	Reactor Stud Rack (Full)	3.6
	j.	Floor Concrete Plugs	1 to 31.5
	k.	Polar Crane Bottom Block and Hook[2]	N/A
	l.	Recirc. Spray Cooler[3]	23.7
	m.	Regenerative Heat Exchanger[3]	2.4
	n.	RHR Exchanger[4]	12.8
	o.	RHR Pump Motor	2.4
	p.	Undefined loads	140.0 (max. main hook) 15.0 (max. aux. hook)
Containment Annulus Monorail			5.0
		Various Loads up to Rated Capacity	5.0 (max.)
Containment Jib Cranes			8.0
		Various Loads up to Rated Capacity	8.0 (max.)
Five Ton Aux. Bldg. Monorail System			5.0
	a.	Component Cooling Water Pump[5]	2.7
	b.	Component Cooling Water Pump Motor[5]	3.2
	c.	Charging Pump[5]	1.3
	d.	Charging Pump Motor[5]	2.1
	e.	Removable Slabs	4.5 (max.)
	f.	Spent Filter Casks[6]	4.0
	g.	Undefined loads	5.0 (max.)
RHR Pump Motor Lifting Lugs			3.0
		RHR Pump Motors	3.0
Ten Ton Aux. Bldg. Monorail System			10.0
		Removable Slabs, Spent Filter Cask[6], and Undefined loads	10.0 (max.)

Table 9B.2-1 (CONTINUED)
HEAVY LOADS[1]

Handling System		Heavy Load	Weight or Capacity (Tons)
Fuel Building Motor Driven Platform & Hoists			2 @ 2.0
		Fuel Pool Gate	1.8
Spent Fuel Crane			125/10
	a.	Spent Fuel Cask (incl. Fuel, Yoke, Lid)	125
	b.	Spent Fuel Cask Yoke	3.3
	c.	Spent Fuel Storage Cask Lid and Tool[8]	6.9
	d.	Spent Resin Container and Cask[9]	N/A
	e.	Irradiated Specimen Cask	5.7
	f.	Fuel Pool Gate	1.8
Low Level Intake Structure			
	a.	Emergency Service Water Pump	4
	b.	Emergency Service Water Pump Diesel Engine	2
	c.	Emergency Service Water Pump Diesel Engine Pedestal	3
	d.	Emergency Service Water Pump Right Angle Gear Drive	3
	e.	Low Level Intake Structure Roof Block	6
	f.	Undefined	2

NOTES TO TABLE 9B.2-1:

1. The loads in the table have been taken from the TER (Reference 3) or subsequent evaluation. Whether or not a specific lift (or a load not listed) will be subject to NUREG-0612 is determined by standards and procedures which address Virginia Power's implementation of NUREG-0612 commitments. All weights and capacities are for reference only, are not controlled and are considered approximate.

2. The crane load block is not subject to NUREG-0612 and does not have a lift procedure since it is an integral part of the crane. To ensure that the load block is not dropped, the redundant hoist limit switches are performance tested prior to use.

3. The recirc. spray cooler and regen. heat exchanger were listed in the TER as subject to NUREG-0612; however, existing maintenance procedures for these items do not permit lifting of the entire heat exchangers. If such lifts are planned in the future, new procedures must be written. Compliance with NUREG-0612 commitments will be determined on a case-by case basis and depends upon whether or not the reactor is defueled and containment systems are isolated from an operating unit during the lift.

4. The RHR heat exchanger was listed in the TER as subject to NUREG-0612. Existing station procedures address performing maintenance which will only be performed while the reactor vessel is defueled; therefore, this lift is not subject to NUREG-0612.

5. Several loads handled by the six-ton monorail in the Aux. Building were listed in the TER as being subject to NUREG-0612. Certain lifts (as footnoted) are not subject to NUREG-0612 since procedural controls prevent loads from being moved over adjacent operational safe shutdown equipment.

6. Spent filter cask not listed in the TER; however it is classified as subject to NUREG-0612 since it is lifted over safe shutdown equipment.

7. Lifts of the reactor head lifting rig (tripod), the reactor internals lifting rig, and RCP motor lifting rig are listed above since each rig weighs more than 1600 pounds; these items were not listed individually in the TER.

8. The lift of the spent fuel cask lid was not included in the TER and is subject to NUREG-0612.

9. Lifts of the spent resin container and its cask are performed in the decontamination building where NUREG-0612 is not applicable.

10. Intermediate lift ring was designed, fabricated, and initially load tested to meet the requirements of NUREG-0612 and ANSI N14.6-1978. Refer to Section 9B.2.4.4 for compliance with the requirements.

Appendix 9C
Flood Control System

Intentionally Blank

APPENDIX 9C FLOOD CONTROL SYSTEM

9C.1 DESIGN BASIS FLOODING

Evaluation of design basis flooding considers the postulated failure of a non-Category I (non-seismic) system resulting in the potential for internal plant flooding, which could affect safety related equipment. Postulated failures were considered in the fire protection system and the non-Category I portions of the circulating water and service water systems. Several design features exist to mitigate the effects of flooding and protect safety related equipment from malfunction. Additionally, consideration was also given to consequence of a potential failure of the short section of exposed Category I circulating water (CW) piping immediately upstream of the condenser CW inlet isolation valve. (See Section 10.3.4.3.)

9C.1.1 Features to Protect Safety Related Equipment Against Failure in the CW/SW Systems

Several design features exist to provide sufficient time for an operator to identify and isolate a postulated flood source prior to it affecting safety related equipment. These features include control room annunciation of high water level in select service water (SW) valve pits, flood water storage volume, safety related equipment flood protection, flood flowrate reduction, and automatic isolation, as applicable.

Dikes

Dikes are installed to provide a barrier to minimize the passage of flood water into areas where safety related components are located. These dikes are two feet high and are located as described below.

The SW valve pits are protected with dikes to prevent flooding of the service water supply motor-operated valves for the recirculation spray (RS), bearing cooling, and component cooling heat exchangers, and the Unit 2 turbine building service water subsystem. These dikes, which are constructed of removable metal plates, encompass the pits as well as separate the two RS SW trains.

The pit which provides entrance to the auxiliary building pipe tunnel is protected with a concrete dike. This dike prevents turbine building floodwaters from entering the auxiliary building.

A removable metal plate dike is located inside the entrance to mechanical equipment room #3 (MER3, MCR Chiller Room) to prevent water flow from MER3 to the emergency switchgear room (ESGR). Additionally, the pipe tunnel from MER3 to the ESGR has been sealed to prevent the passage of floodwater to the ESGR.

A removable metal plate dike is also located at the entrance to the ESGR to restrict turbine building floodwater from entering the ESGR.

A removable metal plate dike is located at the entrance to mechanical equipment room four (MER4) to restrict turbine building floodwater from entering MER4 and potentially affecting the charging pump service water pumps.

A removable metal plate dike is located at the entrance to mechanical equipment room five (MER5) to restrict turbine building floodwater from entering MER5 and potentially affecting the MCR/ESGR chillers.

Amertap Pit

One of the four checkered plates covering each unit's Amertap (CW outlet MOV) pit was replaced with open grating to allow floodwater to freely flow into this pit. This provides additional floodwater storage volume and a more prompt actuation of the Amertap pit high level alarms in the event of turbine building flooding.

Circulating Water Flooding Alarm and Trip System

Level sensing devices are located in the CW intake pit (south side of condenser), the CW outlet pit (north side), and the Amertap pit of both units to actuate a high level annunciator in the main control room. In the event the flooding source is not manually controlled, a separate set of three water level sensing devices will automatically close the CW inlet MOVs when two out of three devices sense a water level of nine inches above the basement floor elevation. These trip probe are located on the floor elevation at the south side and at the northeast and northwest corners of the condenser.

Circulating Water and Service Water Expansion Joints

Each of the circulating water inlet, intermediate outlet, and outlet expansion joints (twelve per unit) and bearing cooling water heat exchanger service water supply and discharge expansion joints (six per unit) is enclosed by a removable flow restriction shield. These shields act as a passive flow restraint to limit water flowrate in the event of a ruptured expansion joint.

Floor Drain Isolation

Two floor drains in the electrical tunnels, two floor drains in the emergency switchgear and relay rooms, three floor drains in mechanical equipment room #3, and the single floor drain in mechanical equipment room #4 have backflow preventors installed to prevent a backflow of water from the turbine building into these areas via the floor drain system. The equipment drain inside the concrete dike in the turbine building near column line C-7 is sealed to prevent backflow of water into the auxiliary building.

9C.1.2 Features to Protect Safety Related Equipment Against Failure in the Fire Protection System

Flooding, caused by failure in the fire protection system, in general, does not adversely affect safety related equipment. Large floodwater storage volumes and the many floor drains and sumps throughout the plant provide adequate time for an operator to identify and isolate a fire protection system flood source before reaching a significant water level. The system of alarms in the fire protection system and area sumps provides the means to alert the operators to a possible fire protection system flood situation. Following source identification, fire protection lines in each building may be readily isolated by a single manual isolation valve located at the supply header to each building. For features which prevent flooding during fire fighting activities see Section 9.10.2.

Specific fire protection system design basis flooding features are discussed in the following paragraphs.

Fuel Building Trip Valve

For the fuel building, a normally closed, fail-open trip valve was installed just outside the building in the six-inch supply header to address potential internal flooding.

The fuel building does not have sufficient floodwater storage volume or sufficient drainage to contain the water which could leak from a catastrophic failure in the fire protection system. The supply line trip valve maintains the system within the fuel building in a dry, depressurized state. The two hose racks within the fuel building each are equipped with a remote control station to open the trip valve when needed. (See Section 9.10.4.14.)

Charging Pump Cubicle Dikes

A two foot high concrete dike prevents floodwater flowing across the auxiliary building Elevation 13 foot floor from entering the charging pump cubicles.

Fire Main Deflector

A six-inch fire protection line runs along the turbine building north wall above the mezzanine level near the ESGR opening. To prevent water from spilling into the ESGR side of the dike located at the ESGR entrance, a flow directing pipe sleeve around the six inch line directs water to either end of the dike surrounded area.

Water Level Monitoring System

In addition to the circulating water flooding alarm and trip system, an alarm system monitors the water level in the auxiliary building, fuel building, main steam valve house, emergency switchgear and relay room, Amertap pits, and the service water valve pits. Upon a high water level signal, an annunciator will sound in the control room. The master flood monitor panel can then be used to determine the location of the flooding area. This system is powered from vital bus circuits to provide reliable indication in the event of a loss of offsite power.

9C.2 INDIVIDUAL PLANT EXAMINATION INTERNAL FLOODING

An Individual Plant Examination (IPE) was performed for Surry in response to Generic Letter 88-20, *Individual Plant Examination for Severe Accident Vulnerabilities*. The purpose of an IPE is to systematically identify plant-specific vulnerabilities to severe accidents and, if justified, define modification of hardware and/or procedures to reduce the probability of core damage. This evaluation is based on plant specifics without regard to component safety classification or qualifications and, therefore, goes beyond the licensing basis in its assessment.

The IPE for Surry identified a vulnerability to internal flooding which warranted changes to the plant and procedures beyond the design basis specified above in Section 9C.1, Design Basis Flooding. Hardware modifications and procedural changes made to address the internal flooding vulnerability include those items discussed in the following paragraphs.

The most significant flood sources identified by the IPE were RWST piping in the auxiliary and safeguards buildings, SW system in MER3, and CW/SW systems in the turbine building.

Failure of the safety-related RWST suction piping to the containment spray, charging (HHSI), and low head safety injection pumps may cause significant flooding of the safeguards or auxiliary buildings. Floodwater from the safeguards building would propagate to the auxiliary building through interconnecting pipe tunnels. Flooding the auxiliary building would subsequently affect the component cooling water pumps and charging pumps once the water depth reached approximately eighteen inches. Loss of both of these systems could lead to RCP seal failure due to loss of seal injection and loss of thermal barrier cooling.

Backflow preventors have been installed in each charging pump cubicle's floor drain to minimize the probability of common mode flooding of both unit's pumps via the common auxiliary building floor drain system. The pipe penetrations into the charging pump cubicles which could be submerged during a flooding event are sealed to minimize passage of floodwater.

Rupture of the CW/SW system in the turbine building can lead to a spectrum of potential floodrates. The lower probability—but higher consequence—flood events, if not isolated, can lead to flooding of the ESGR and subsequent core damage. Plant design features associated with Design Basis Flooding (Section 9C.1) were considered in the IPE. Additional plant modifications were implemented to reduce the overall probability of core damage. One of these modifications was the installation of removable flow restriction shields around the rubber expansion joints immediately downstream of the service water isolation MOVs serving the bearing cooling heat exchangers (both units) and the component cooling heat exchangers. Another plant modification was implemented to limit the potential effects of a SW failure in MER3. A watertight door at the entrance to MER3 was installed to delay the progression of flooding originating in MER3 into the ESGR. The door assembly includes a two foot tall bottom panel (dike) which permits access to MER3 during flooding events (until flood level reaches two feet) and is removable to permit access for heavy equipment during maintenance activities. The upper door section is normally closed and sealed (unless personnel are in MER3). The door assembly is designed for seismic or hydrostatic loadings (non-simultaneous). The north, south (adjacent to MER4), and west wall penetrations in MER3, which could be submerged during a flooding event, were modified by applying a watertight sealant.

Additionally, operation of the turbine building sump pumps can delay or prevent floodwater from entering the ESGR. To ensure availability of these pumps, an administrative limit for minimum number of functional pumps has been instituted, as well as surveillance testing and preventive maintenance. The turbine building sump pumps remove floodwaters resulting from ruptures in the turbine building which flow via the floor drain system into the sump. To enhance removal of water associated with overflow of the floor drains in the turbine building, the checkered plate manhole covers over each sump were replaced with open grating.

Although these modifications were not quantified in terms of reduction in the overall probability of core damage, two enhancements were also implemented to address the internal flooding vulnerability. These two enhancements are:

1. Turbine building flooding which occurs as a result of a rupture in the CW or SW system upstream of the first canal isolation valve can be isolated by installing the seal plates at the high level intake structure. Rollers have been added to the plates to enhance their ability to slide into place under flow conditions without binding. (The rollers were later removed as part of an improvement of the stop log guide structure.)
2. To enhance the ability to isolate flow to the condenser waterboxes or downstream rupture during flooding conditions, the motor operators for the inlet valves have been modified for operation while submerged.

Procedures have been revised to reflect sensitivity related to potential turbine building flooding resulting from certain maintenance activities. Where appropriate, maintenance procedures require that a flood watch be posted during the maintenance evolution and that double isolation be established prior to initiation of the maintenance effort.

Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 10

Intentionally Blank

Chapter 10: Steam and Power Conversion
Table of Contents

Chapter 10: Steam and Power Conversion
Table of Contents (continued)

Chapter 10: Steam and Power Conversion

List of Tables

Chapter 10: Steam and Power Conversion

List of Figures

CHAPTER 10 STEAM AND POWER CONVERSION

10.1 GENERAL DESCRIPTION

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

This chapter describes the systems and equipment that are required to convert steam energy to electrical energy. The following sections describe separate equipment and systems required for each unit:

10.3.1 Main steam system

10.3.2 Auxiliary steam system

10.3.3 Turbine generator

10.3.5 Condensate and feedwater system

10.3.6 Condenser

10.3.7 Lubricating-oil system

10.3.9 Bearing cooling water system

The following sections describe those systems that are shared in the operation of both units:

10.3.4 Circulating water system

10.3.8 Secondary vent and drain system

The potential for radioactive contamination of the secondary steam system is discussed in Chapter 11.

Intentionally Blank

10.2 DESIGN BASES

The design bases of the steam and power conversion equipment and systems are largely derived from past design experience with fossil-fueled stations, and have evolved over a long period of time. Specifically, the design bases are oriented to a high degree of operational reliability at optimal thermal performance. The performance of the collective equipment and systems is a function of environmental conditions and the selection of design options. Therefore, the principal design basis is represented by the design heat balances, which incorporate all of the applicable design considerations.

Figure 10.2-1 and Reference Drawing 1 shows the heat balance for the extended rating equivalent to 2558 MWt.

The conventional design bases have been modified in order to provide suitability for nuclear application, and these include provisions for specific earthquake, tornado, and missile protection as further described in other sections.

Turbine building Reference Drawings 2 through 9 show equipment locations.

A steam generator repair program was completed at the Surry Power Station in 1980 and 1981 for Units 2 and 1, respectively. The purpose of the program was to repair degradation caused by corrosion-related phenomena and to restore the integrity of the steam generators to a level equivalent to new equipment. The repair program basically consisted of replacing the steam generator lower assembly and refurbishing the upper assembly. New primary moisture separation equipment was installed in the upper assembly. The steam generators are described in Section 4.2.2.3 (primary-side characteristics) and Section 10.3.1.2 (secondary-side characteristics).

10.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-59M	Heat Balance Diagram: 100% Core Power, Unit 1
	11548-FM-59A	Heat Balance Diagram: 100% Core Power, Unit 2
2.	11448-FM-6A	Machine Location: Turbine Area, Plan, Operating Level, Unit 1
	11548-FM-6A	Machine Location: Turbine Area, Plan, Operating Level, Unit 2
3.	11448-FM-6B	Machine Location: Turbine Area, Plan, Mezzanine Level, Unit 1
	11548-FM-6B	Machine Location: Turbine Area, Plan, Mezzanine Level, Unit 2
4.	11448-FM-6C	Machine Location: Turbine Area, Plan, Ground Floor, Unit 1
	11548-FM-6C	Machine Location: Turbine Area, Plan, Ground Floor, Unit 2
5.	11448-FM-6D	Machine Location: Turbine Area, Sections, Sheet 1, Unit 1
	11548-FM-6D	Machine Location: Turbine Area, Sections, Sheet 1, Unit 2
6.	11448-FM-6E	Machine Location: Turbine Area, Sections, Sheet 2, Unit 1
	11548-FM-6E	Machine Location: Turbine Area, Sections, Sheet 2, Unit 2
7.	11448-FM-6F	Machine Location: Turbine Area, Sections, Sheet 3, Unit 1
	11548-FM-6F	Machine Location: Turbine Area, Sections, Sheet 3, Unit 2
8.	11448-FM-6G	Machine Location: Turbine Area, Sections, Sheet 4, Unit 1
	11548-FM-6G	Machine Location: Turbine Area, Sections, Sheet 4, Unit 2
9.	11448-FM-6H	Machine Location: Turbine Area, Sections, Sheet 5, Unit 1
	11548-FM-6H	Machine Location: Turbine Area, Sections, Sheet 5, Unit 2

Figure 10.2-1
UNIT 1 HEAT BALANCE DIAGRAM 40°F CW INLET TEMPERATURE

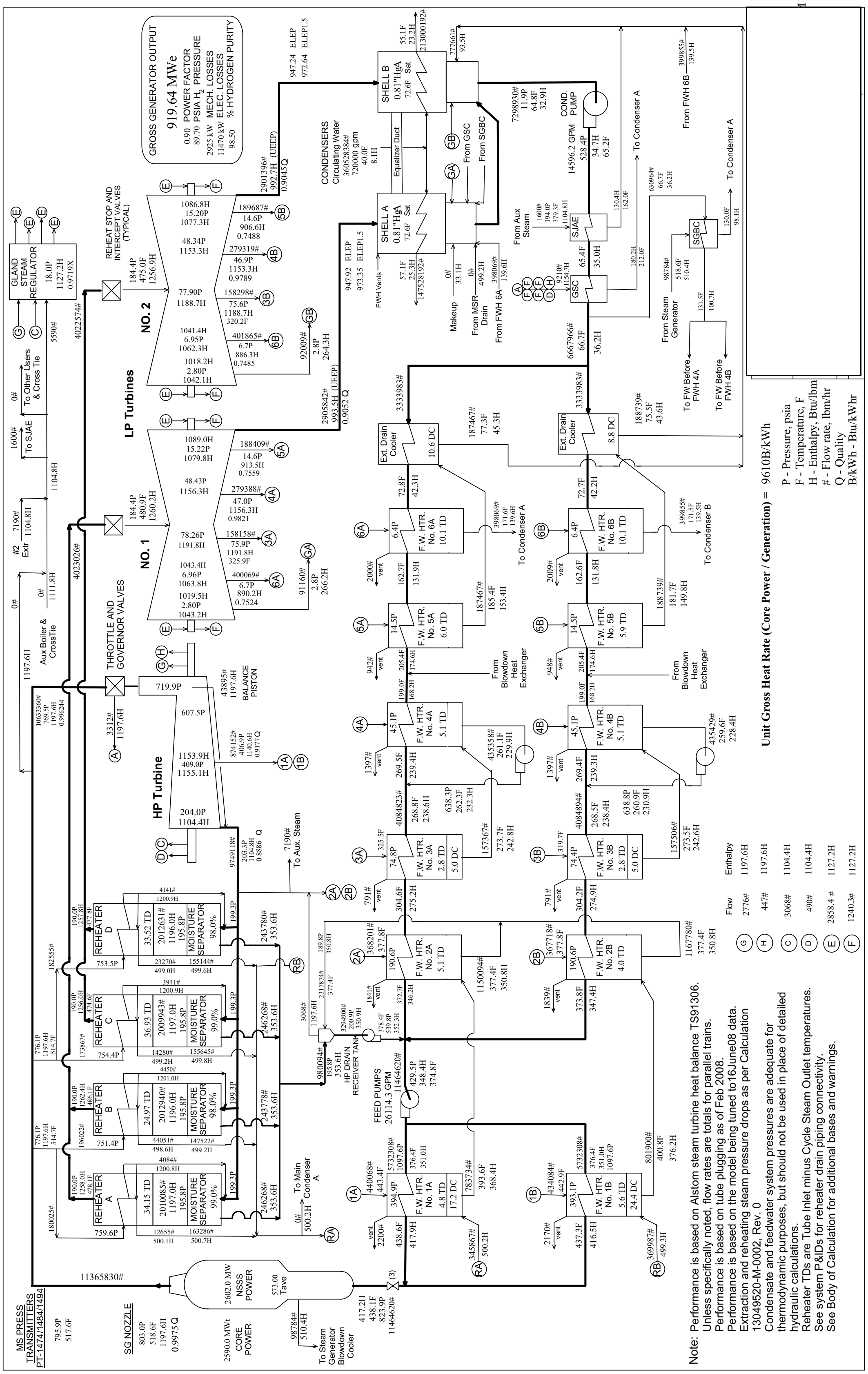


Figure 10.2-2
UNIT 1 HEAT BALANCE DIAGRAM 95°F CW INLET TEMPERATURE

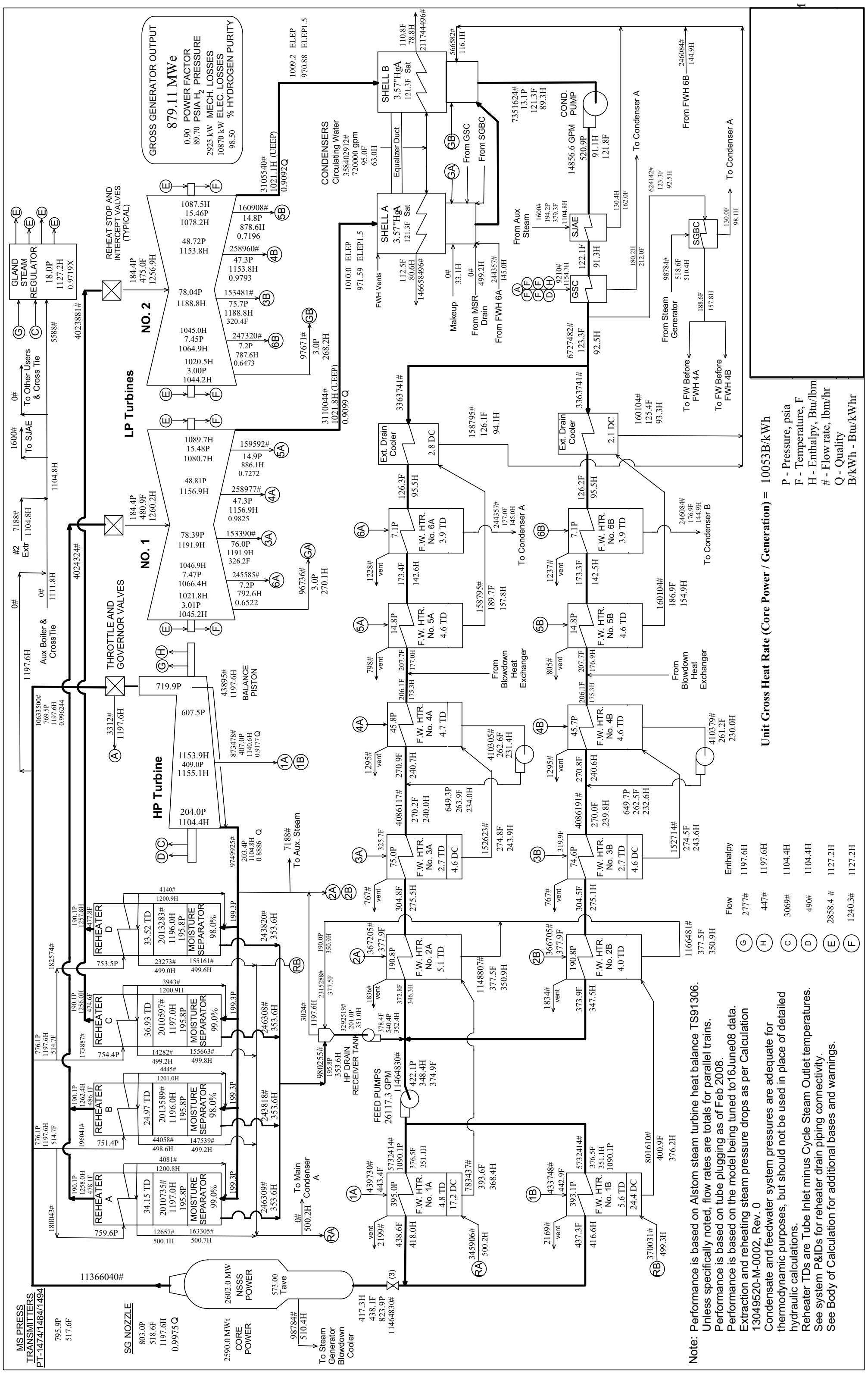


Figure 10.2-3
UNIT 2 HEAT BALANCE DIAGRAM 40°F CW INLET TEMPERATURE

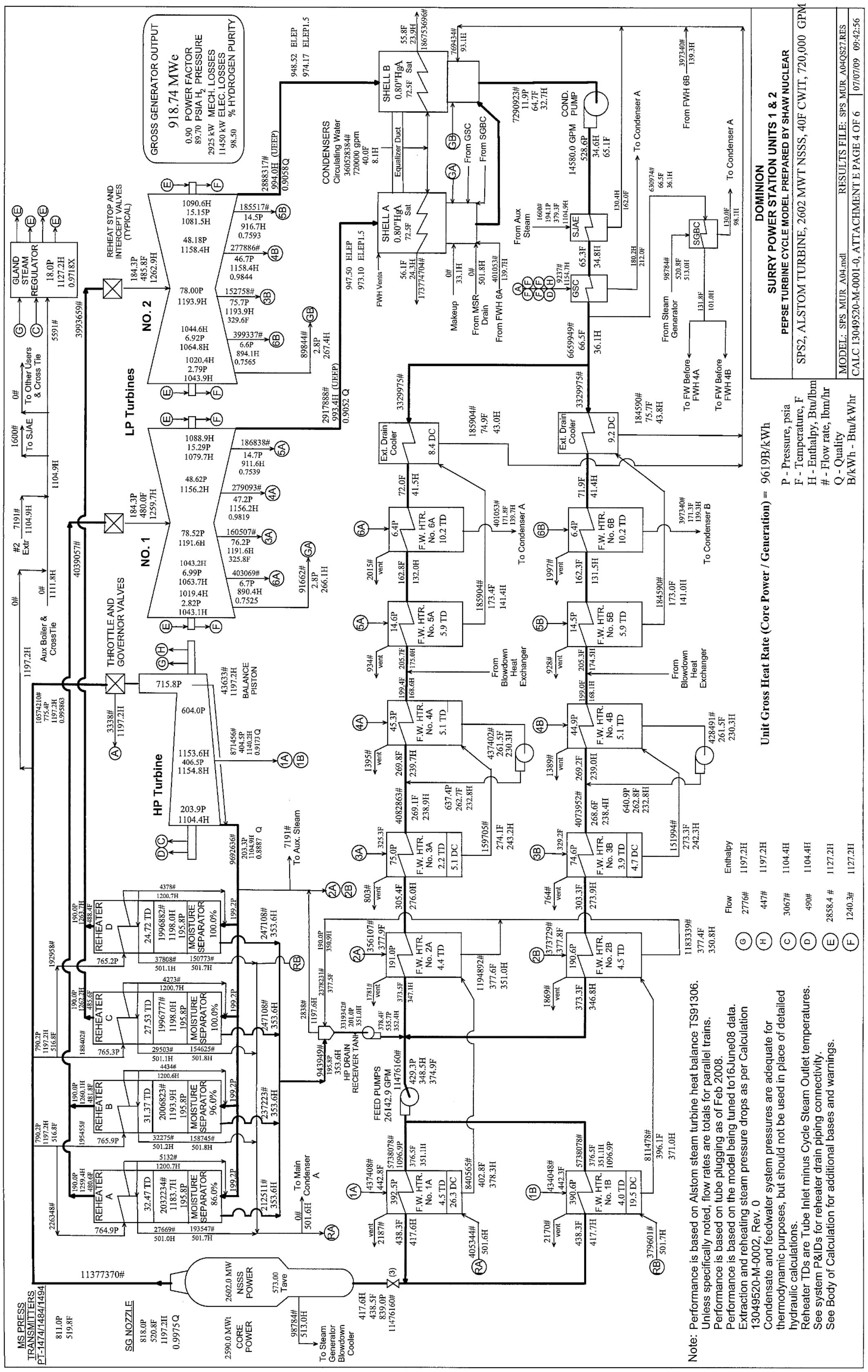
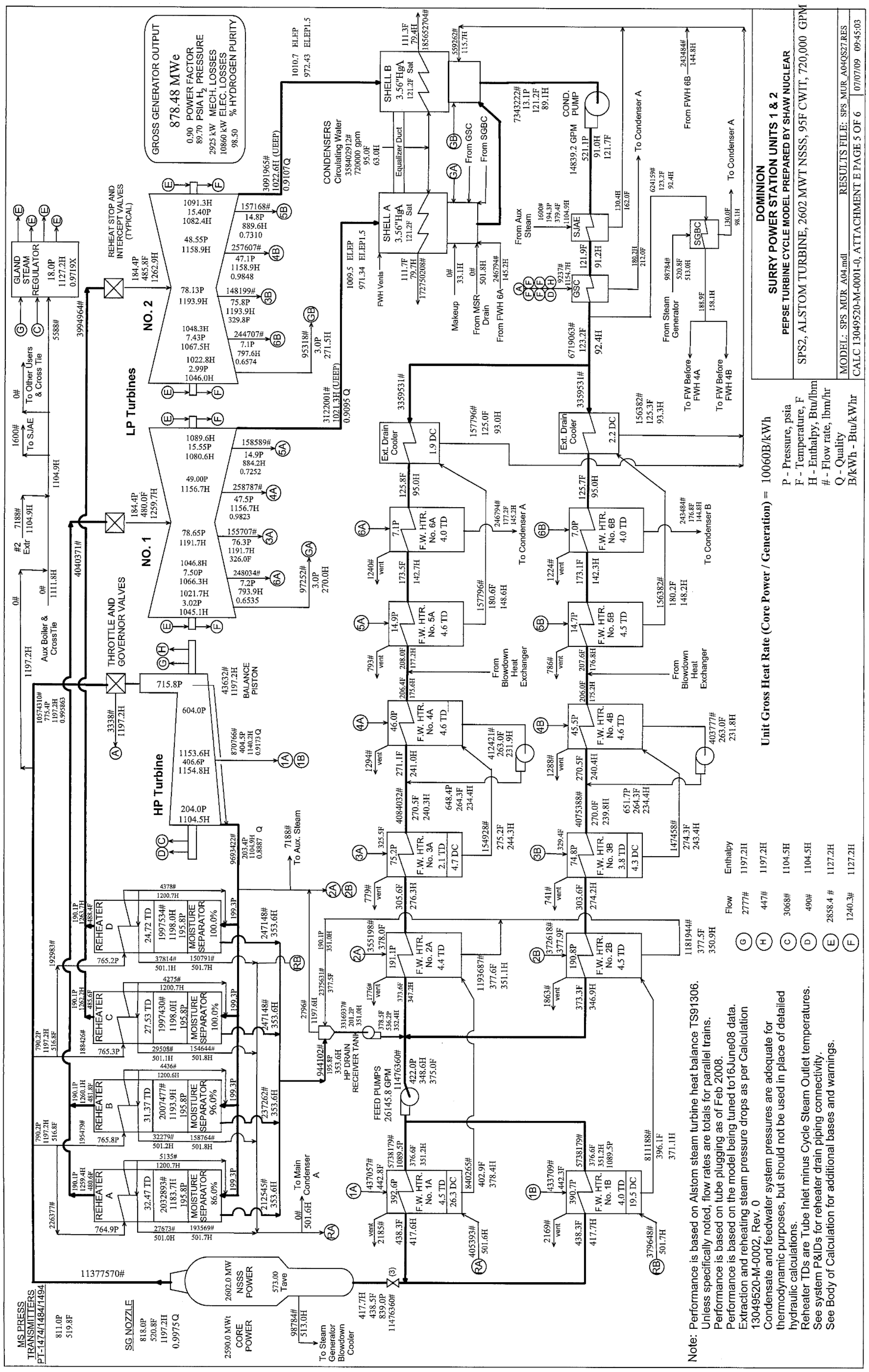


Figure 10.2-4
UNIT 2 HEAT BALANCE DIAGRAM 95°F CW INLET TEMPERATURE



10.3 SYSTEM DESIGN AND OPERATION

10.3.1 Main Steam System

The main steam system is shown on Figure 10.3-1 and Reference Drawing 1. The turbine generator heat balance for a bounding NSSS power of 2602 MWt is shown on Figures 10.2-1 through 10.2-4 and Reference Drawing 10. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the main steam system was found to be adequate.

10.3.1.1 **Design Basis**

Each of the three main steam pipes is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1, for a flow of 3,722,641 lb/hr of steam at 1085 psig, 555°F. The pipes are each 30-inch o.d. ASTM A-155, Class 1, Gr. CMS-75 carbon steel, 1-inch nominal wall thickness, and join to form a common 36-inch o.d. header. Additional discussion of main steam piping materials may be found in Section 14B.5.1.6.3. Steam flows from this header through four 28-inch o.d. pipes to the stop trip valves and the turbine.

The steam dump system is sized to take the excess steam flow associated with a 50% load reduction. The steam dump system in conjunction with the reactor control system, mitigates a 50% load reduction transient without tripping the reactor. The steam dump system has a capacity of between 28 and 43%, which ranges from approximately 3,336,000 to 4,654,000 lb/hr. This flow can be divided equally through the eight bypass control valves, with each valve having a maximum capacity of 890,000 lb/hr at full load steam conditions.

The 4200-rpm turbine-driven auxiliary feedwater pump is designed to deliver 700 gpm of auxiliary feedwater to the steam generators at main steam pressures from 600 psig to 1100 psig. The turbine-driven auxiliary feedwater pump will also operate at main steam pressures from 600 psig down to less than 120 psig and deliver the required auxiliary feedwater flow to the steam generators to support Reactor Coolant System (RCS) decay heat removal prior to placing the residual heat removal system in service. A main steam pressure of 120 psig corresponds to the approximate RCS conditions at which the residual heat removal system can be placed in service to remove decay heat. Steam traps drain condensate from upstream of the inlet control valves to prevent water slugs from entering the turbine. Removal of this condensate minimizes the risk of water slugs entering the turbine, flashing, and causing a pump trip on turbine overspeed.

The main steam piping supports were initially analyzed for turbine trip forces as well as for seismic forces. Since the turbine trip results in a more severe shock to the piping system than the design-basis earthquake, as set forth in Section 2.5, the turbine trip data were used in the design of the piping supports. In addition, the system was stress-analyzed for the forces and moments that result from thermal growth. The main steam piping within the containment annulus was reviewed for possible pipe rupture, and sufficient supports and guides were provided to prevent damage to the containment liner and adjacent piping. Stresses in the main steam piping inside containment have been reviewed and, in accordance with NRC Generic Letter 87-11, are sufficiently low that only terminal end breaks need be postulated.

As a result of IE Bulletin 79-14 (Reference 1), the main steam piping and supports were reanalyzed in accordance with updated regulatory requirements. Minor support modifications were made to satisfy analytical load limits. Pipe stresses were within allowable limits, so no piping modifications were necessary. The reanalysis of safety-related piping systems and supports is discussed in Appendix 15A.

10.3.1.2 **Description**

Each loop of the reactor coolant system contains a vertically mounted U-tube steam generator. The secondary-side characteristics of the steam generators are described below. The primary-side characteristics are described in Chapter 4. Steam generator design data are given in Table 4.1-4.

The steam generators, as shown on Figures 10.3-2 and 10.3-3, consist of two integral sections: an evaporator section and a steam drum section. The evaporator section consists of a U-tube heat exchanger, while the steam drum section houses moisture-separating equipment. The steam drum section is located in the upper part of the steam generator. In general, the steam generators are designed and manufactured in accordance with Sections II, III, and IX of the ASME Boiler and Pressure Vessel Code. The lower assemblies are designed and manufactured in accordance with the 1974 Edition of the ASME Code, including Addenda through Winter 1976. All components are designed to meet Section XI, *Rules For Inservice Inspection of Nuclear Power Plant Components*. The steam generator lower assemblies bear the applicable ASME Code stamp.

Feedwater enters the unit through the nozzle located on the upper shell and is distributed by a feedwater ring into the downcomer annulus formed by the tube wrapper and steam generator shell. The feedwater mixes with recirculation flow and enters the tube bundle near the tubesheet.

The circulation ratio, which is defined as the total tube bundle flow divided by the feedwater flow and is directly proportional to the steam quality exiting the tube bundle, is approximately 3.8. As circulation ratio increases, certain parameters of the steam generator, such as lateral velocity, steam quality, void fraction, and number of tubes exposed to sludge, change in a favorable direction. Low steam quality in the bundle reduces tube exposure to local steam blanketing. This also reduces the number of potential areas of concentration for chemical impurities. In addition, higher circulation ratios increase the flow exiting the downcomer and sweeping across the tubesheet to the center of the bundle. The point of highest steam quality and thus the lowest density is the center of the tube bundle, though, and is thus more susceptible to chemical concentration and sludge deposition. It is for this reason that the blowdown intake is located in this region.

A set of sixteen 20-inch-diameter centrifugal moisture-separators, located 13 inches above the tube bundle, removes most of the entrained water from the steam. Steam dryers are employed to increase the steam quality to a minimum of 99.75% (0.25% moisture). The steam drum has two bolted and gasketed access openings for inspection and maintenance of the dryers, which can be disassembled and removed through the opening.

The lower assemblies are constructed with four additional 6-inch access ports and two 2-inch access ports in the area of the tubesheet. Four 6-inch access ports are located slightly above the tubesheet 90 degrees apart, with two located on the tube lane. Two additional 6-inch access ports are located on the tube lane, between the flow distribution baffle and the first support plate. At this same elevation, 90 degrees away, are two 2-inch access ports. The addition of these access ports improves and promotes inspection of the tubesheet and flow distribution baffle and assists in the sludge-lancing procedure. The steam generator wrapper is designed to discourage flow in the tube lane yet allow clear access from the access ports.

Feedwater exiting from behind the wrapper in the vicinity of the tube lane will tend to preferentially channel to this path of less resistance and bypass part of the tube array. In order to prevent this flow channeling, a series of plates are placed in the tube lane. These plates block the flow into the tube lane and prevent channeling. These plates are arrayed so that there will be no interference with the sludge-lancing procedure.

A flow distribution baffle is located approximately 18 inches above the tubesheet. This baffle has a cutout center section and quatrefoil tube holes. The increased circulation ratio provides a greater lateral flow across the tubesheet surface. The baffle plate will assist in redirecting the flow across the tubesheet, then up the center of the bundle through the center cutout. The design is sized to minimize the number of tubes exposed to sludge. Consistent with this purpose, the design causes the sludge to deposit in and near the center of the bundle at the blowdown intake. The flow distribution baffle plate material is SA-240 type 405 ferritic stainless steel.

The tube support plates are SA-240 type 405 ferritic stainless steel. This material is ASME Code approved and is resistant to corrosion with the chemistry expected during the operation of the steam generator. In addition, SA-240 has a low wear coefficient when paired with Inconel and has a coefficient of thermal expansion similar to carbon steel. Corrosion of SA-240 results in an oxide which has approximately the same volume as the parent material, whereas corrosion of carbon steel results in oxides that have a greater volume than the parent material. Type 405 also has material properties important to fabrication that are equivalent to carbon steel.

The quatrefoil tube support plate design, as shown on Figure 10.3-4, consists of four flow lobes and four support lands. The lands provide support to the tube during all operating conditions, while preventing wear or fretting. This design has a lower pressure drop than the most current circulation hole designs. This low secondary pressure drop will cause a high circulation ratio which, when combined with other improvements, translates into higher sweeping velocities and fewer tubes exposed to a low steam quality at the tubesheet. This design directs the flow along the tubes, which limits steam formation and chemical concentrations at the tube-to-tube support plate intersections.

Each steam generator has two 2-inch, schedule 40 Inconel internal blowdown pipes. The blowdown rate from the steam generator is varied as required by chemistry conditions in the feedwater and as monitored in the blowdown. Maintenance of the steam-side water chemistry is assisted through the use of the blowdown system. Therefore, a continuous blowdown is preferred to intermittent blowdown. Continuous blowdown of the steam generator provides a dynamic system that is constantly removing impurities from the steam generator. During hot standby and hot functional testing, blowdown is employed as needed to maintain the steam generator chemistry within specification. The blowdown intake location is coordinated with the baffle plate design so that the intake is located where the greatest amount of sludge deposition is expected to occur. The design of the steam generators allows the use of an efficient sludge removal system; a typical system is shown on Figure 10.3-5. A permanent sludge removal system is not installed. A review of the effects of the power uprate to a core power of 2587 MWt was conducted and the main steam generator blowdown system was found to be adequate.

Steam-generator blowdown is discharged from the steam generators through two 2-inch schedule 40 Inconel internal blowdown pipes. The steam generators are designed to allow blowdown rates up to 7.4% of the feedwater flow rate; however, much of this is excess capacity because the blowdown system has a capacity of 1% of the feedwater flow rate.

A 3-inch line downstream of each steam generator blowdown containment isolation valve carries the blowdown effluent from the auxiliary building into the turbine building. Each blowdown line has a manual isolation valve, with a bypass valve provided for system start-up. Each blowdown line has a heat exchanger located adjacent to the east wall of the respective turbine building.

The system is designed for a maximum continuous blowdown from each steam generator of 70 gpm at 750 psig and 510°F, and reduces the blowdown water to a maximum temperature and pressure of 130°F and 60 psig.

During power operation, after the blowdown is cooled, it is normally directed to the condenser hotwell. The blowdown, along with condensate in the condenser, is filtered and treated by condensate polishing prior to being returned to the steam generators. Alternately, steam generator blowdown may be released to the discharge canal through the condenser outlet waterbox. This activity is described in Section 10.3.5.2. Releasing to the discharge canal is normally limited to unit start-up operation.

A pressure control valve (PCV) and a hand control valve (HCV) are provided downstream of each heat exchanger assembly. The PCV will maintain a constant nominal pressure of 250 psig upstream of the HCV. If pressure upstream of the PCV decreases below 250 psig, the valve will travel to the full-open position. The PCV will fail closed on a loss of control air, blowdown flow greater than 75 gpm, or heat exchanger assembly outlet temperature greater than 145°F. The HCV is provided for remote/manual control of the steam generator blowdown rate. A remote control station is provided in the control room to position the HCV. The HCV is sized for a maximum blowdown rate of 70 gpm with an upstream pressure of 250 psig and a downstream pressure of 50 psig. A pressure relief valve, set for approximately 200 psig, is provided to protect the system downstream of the HCV from overpressurization. A manually operated bypass valve is provided around both the PCV and the HCV to allow manual control of the blowdown flow. Two flow elements are provided between the heat exchanger assembly and the PCV for high-range and low-range flow indication.

Main condensate is used as the cooling medium for the heat exchangers. Approximately 1260 gpm per unit (three heat exchangers) is supplied through an 8-inch supply header and isolation valve. The supply connection from the condensate system is located on the 24-inch condensate header between the gland exhaust condenser and the flash evaporator. The return line ties into the condensate system at the cross-connect line between the fourth and fifth point feedwater heaters. Manual isolation valves are provided on each heat exchanger assembly. The outlet isolation valve is a globe valve to permit throttling of the cooling water flow. Thermometers are installed in the cooling water lines at the outlet of the heat exchanger assemblies to monitor condensate return temperature. A relief valve is provided for each heat exchanger assembly between the isolation valves. The differential pressure across the drain coolers, fifth, and sixth point heaters will provide sufficient head for condensate flow through the steam generator blowdown (SGBD) heat exchangers. To increase the condensate cooling capacity of the SGBD heat exchangers during low main condensate flow conditions, an independent SGBD heat exchanger condensate return divert line is added. The diverted heat exchanger condensate return flow is controlled by a temperature controlled valve (TCV) which allows the diverted flow to be discharged to the main condenser when the heat exchangers' blowdown exit temperature reaches 135°F.

Codes and standards applied to the steam generator blowdown system are listed in Table 10.3-1. The piping from the 3-inch connection downstream of the steam generator blowdown containment isolation valves to the heat exchanger assemblies is classified as high-energy piping. This portion of the steam generator blowdown system is not safety related and has no seismic or tornado design requirements, except that its failure must not cause a functional loss of any safety-related equipment. Postulated breaks have been analyzed, and restraints added to prevent pipe whip or jet impingement damage to systems in the auxiliary building that are required for safe shutdown.

A blowdown sampling system is provided in the Unit 1 turbine building. The system is used to analyze a cooled blowdown sample before the blowdown stream is discharged to the discharge canal through the condenser waterbox outlet.

A 2-inch nozzle in the upper shell facilitates the wet layup of the steam generators during the periods of inactivity. The wet layup nozzle can be used for addition of chemicals during these periods to prevent any excursions of the water quality in the steam generator. The nozzle can also be used in conjunction with other systems to circulate water through the steam generator during periods of layup to prevent localized chemical concentrations. These same connections can also be used for chemical cleaning.

A steam generator recirculation and transfer system is provided to protect the steam generator internals from corrosive attack during inactive periods by enabling the water chemistry to be controlled during such periods. The system is used in conjunction with the steam generator nitrogen system described below to ensure the exclusion of oxygen from the steam generator internals during wet layup conditions. Each steam generator has an independent external recirculation loop with 150-gpm pumping capacity, which provides a complete volume turnover approximately every 4 hours. The recirculation and transfer system pump takes suction from the steam generator upper shell. The pump discharges to the steam generator through the blowdown pipe via a connection to the steam generator blowdown system. Each circulation loop has a cross connect to facilitate the transfer of a steam generator’s contents to either of the other two steam generators, the liquid waste system, or the circulating water discharge. During normal plant operation, the system will be isolated from the steam generator by double isolation valves. A typical wet-layup system is shown in Figure 10.3-6.

The steam generator nitrogen system is utilized in conjunction with the steam generator recirculation and transfer system to protect the steam generators during long layup periods from corrosive attack by ensuring the exclusion of oxygen from the secondary side of the steam generators. The system includes a vacuum pump to enable the air to be evacuated from the steam generator before nitrogen is introduced from a nitrogen supply. However, the vacuum pump is no longer used. Connection to the secondary side of the steam generator is made by a 2-inch line connected to the 6-inch main steam trip valve bypass line in the main steam valve house. An isolation valve is provided to isolate this system from the steam system during unit operation. This system is a quality group B system from the bypass line up to and including the isolation valve, with the rest of the system being quality group E.

A loose parts monitoring system has been installed and provides the ability to monitor the primary system and secondary side of the steam generators for the presence of loose circulating parts and other foreign objects. See Section 4.2.10 for further information.

All pressure-containing parts, with the exception of the Inconel tubes, are made of carbon or low-alloy steel. The stainless steel insulation of the steam generator is designed to facilitate removal for maintenance and inservice inspection activities.

Steam is conducted from each of the three steam generators through a steam flowmeter (venturi), a swing disk-type valve and an angle-type nonreturn valve into a common header outside the containment. The steam passes from the header to the turbine stop-trip valves and then to the governor valves. The steam flowmeter sends a signal to the feedwater control system.

The swing disk-type trip valves in series with the nonreturn valves contain swinging disks that are normally held up and out of the main steam flow path by air cylinder operators. Three-way solenoid-operated air control valves function to hold the trip valves open when air pressure is applied. The valves are designed to close on release of air pressure, but are not dependent on air pressure to assist closure. When the air pressure is vented, the valve discs shut rapidly due to spring pressure and the steam flow differential pressure. The air cylinders are equipped with rupture discs to prevent damage to valve and actuator parts from being overstressed due to the rapid cylinder pressure increase when the valves shut at high steam flow rates. Air is normally available at 100 psig, but the equipment is designed to operate at a minimum air pressure of 70 psig. Electrical power to the solenoid-operated air control valves is available at 125V dc.

The main steam-line trip valve circuitry has been modified to ensure that the trip valves will not return to their non-safety position (open) following the resetting of the consequence limiting safeguards (CLS) system signal when power to train A or B is lost. The modification required the installation of an additional contact deck to each trip valve selector switch located at the benchboard in the control room and the installation of a new limit switch to each trip valve. This modification provides a seal-in function in the train B control circuitry similar to that existing in the train A portion of the circuit. As a result, when resetting a CLS signal, if power is lost in either train A or B, the valve will not return to its non-safety position. All electrical equipment installed due to the above modification that could experience a harsh environment is qualified to IEEE 323-1974, IEEE 344-1975, and IEEE 383-1974.

The trip valves close following receipt of an excess flow signal from the steam flowmeter to the solenoid-operated air control valves. The electrical signal positions the air control valves to release air pressure on the air cylinder operators, and spring action causes the trip valve disks to move into the steam path and trip closed. The operating mechanisms are designed and constructed to withstand the pressures and temperatures that result from dashpot action after the valve disk has moved into the steam path. Rapid closure of the trip valves prevents flashing of the water on the shell side of the steam generators, which in turn prevents a rapid decrease in reactor coolant temperature on the tube side of the steam generators.

In addition to the three-way solenoid-operated air control valves described in this section, two solenoid-operated valves have been added to each main steam line trip valve to provide an alternate means of closure at either the control room (in the event of a fire in the emergency switchgear room) or at the emergency switchgear room (in the event of a fire in the control room). The cables, solenoid valves, control switches, and battery/battery chargers required to power the two additional SOV’s are qualified to meet or exceed the normal environmental conditions for the areas where they will be installed. The cables that supply the two SOVs are environmentally qualified in accordance with IEEE 323-1974. See Section 9.10.4.1 for information on 10 CFR 50 Appendix R requirements in relation to this modification.

The air operators are also used to open the trip valves. With 70 psig applied to both operators, the trip valves will open with a maximum differential pressure of 4 psi across the valve seat. Manually operated bypass valves permit pressure to be balanced across the valve before reopening.

The motor-operated nonreturn (stop-check) valves automatically prevent reverse flow of steam in the case of accidental pressure reduction in any steam generator or its piping, and also provide a shut-off of steam from its respective steam generator.

A total of five ASME Code safety valves are located on each main steam line outside the reactor containment and upstream of the trip valves. Four 6-inch by 10-inch valves and one 4-inch by 6-inch valve are provided, for a total relieving capacity of 3,842,454 lb/hr.

Excess steam generated by the residual and sensible heat in the core and the reactor coolant system is normally bypassed directly to the condensers by means of two 14-inch steam dump lines, which provide a total bypass capacity of 40% of normal full-load steam flow. Each steam dump line contains a bank of four steam dump control valves arranged in parallel. These valves are controlled by reactor coolant average temperature with provisions to control a portion of the valves with steam pressure. An uncontrolled unit cooldown caused by a single valve sticking open is minimized by the use of a group of valves installed in parallel.

All or several of the steam dump valves open under the following conditions, provided a condenser vacuum permissive interlock is satisfied:

1. On a large step load decrease, the steam dump system creates an artificial load on the steam generators, thus enabling the nuclear steam supply system to accept a 50% load rejection from the maximum capability power level without reactor trip. An error signal exceeding a set value of reactor coolant T_{avg} minus T_{ref} will fully open all valves in 5 seconds. T_{ref} is a function of load and is set automatically. The temperature-controlled valves close automatically as reactor coolant conditions approach their programmed set-point for the new load.
2. On a turbine trip with a reactor trip, the pressure in the steam generators rises. To prevent overpressure without main steam safety valve operation, the steam dump valves open and discharge to the condenser for several minutes, to provide time for the reactor control system (Section 7.3) to reduce the thermal output of the reactor without exceeding acceptable core and coolant conditions.
3. After a normal orderly shutdown of the turbine generator leading to unit cooldown, the steam dump valves are used to release steam generated from the residual and sensible heat for several hours. Unit cooldown is controlled to minimize thermal transients and is based on residual and sensible heat release. It is effected by manual control of the steam dump valves until the cooldown process is transferred to the residual heat removal system (Section 9.3).

4. During start-up, hot standby service, or physics testing, the steam dump valves are operated from the control room. The Steam Header Pressure Controller can be used in the Automatic or Manual control mode while maintaining the plant at no load conditions or during start-up with power less than approximately 15%.

All steam dump valves are prevented from opening on loss of condenser vacuum, and excess steam pressure is relieved to the atmosphere through the steam generator power operated relief valves or the main steam safety valves. Interlocks are provided to reduce the probability of spurious opening of the steam dump valves.

An interlock is also provided to close all steam dump valves by venting the valve actuators whenever the reactor coolant system temperature in two out of three loops falls below 543°F (nominal). This interlock is redundant down to two solenoids per steam dump valve, which vent the valve actuator. This interlock ensures that any failure in the steam dump control system occurring in the normal operating temperature range above 543°F (nominal) can cause a cooldown only to 543°F (nominal) at which point all valve actuators are vented and, thus, all valves are closed.

A steam generator power operated relief valve with an adjustable setpoint is provided on each main steam safety valve header, upstream of the trip valve outside the containment. The relieving pressure of these valves, normally 1035 psig, is individually controlled from the control room, and each valve has a capacity of 373,000 lb/hr. A key lock selector switch EMERG CLOSE—NORMAL has been added to the existing analog circuit of the associated controls for each of the three power operated atmospheric relief valves. This provides the operator with the ability to close the relief valves by interrupting the analog signal, which normally controls the position of the relief valves. These selector switches are located in the cable vault and tunnel where the operator can operate the relief valves in the event of a fire in the control room or the emergency switchgear room. These valves which are equipped with quick-connect instrument air fittings can be operated locally with a portable air source if required. The steam generator power operated relief valves are equipped with a backup bottled air system so that they can be operated from within the containment spray pump house in the event of loss of offsite power. Additionally, a beyond design basis (BDB) backup air bottle system also exists for operating the steam generator (SG) power operated relief valves (PORV) during a beyond design basis external event (BDBEE) resulting in damage to the backup air bottle system. This BDB backup air bottle system is contained inside the Main Steam Valve House (MSVH), which is a safety related, seismic structure that is tornado missile protected. This system also provides a means to connect an external air source, such a a portable air compressor.

Steam leaving the high pressure turbine passes through four moisture separator-reheater units in parallel to the inlets of the low pressure turbine cylinders. Each of the four steam lines between the reheater outlet and LP turbine inlet is provided with a crossover stop valve and an intercept valve in series. These valves, operated by the turbine control system, function to control turbine overspeed. Six ASME code safety valves are installed on each crossunder line between the high pressure turbine exhaust and the moisture separator inlet to protect the separators and crossunder system from overpressure. The valves are sized to pass the flow resulting from closure of the crossover stop and intercept valves with the main steam inlet valves wide open. Although this event is unlikely, the valves discharging to atmosphere prevent equipment damage.

Steam is supplied to the turbine drive for the auxiliary feedwater pump from each steam line upstream of the main steam trip valves. The steam lines to the turbine are continuously under steam generator pressure up to the shut-off valves located at the turbine drive. The air-operated steam supply valves for the auxiliary feedwater pump are operable from the control room or the auxiliary shutdown panel. Operation of these valves is also initiated automatically from a loss of power signal or on a low-low level signal in two of three steam generators. Indication of operating conditions is provided in the control room to enable the operator to adjust feedwater flow with any of the six motor operated valves shown on Reference Drawing 6.

Temperature flow probes are installed on the discharge side of the 15 main steam safety valves to monitor safety relief valve position on the main steam system. Valve position is indirectly “measured” by comparing discharge temperatures with respect to ambient temperatures with the valve closed. This indirectly determined valve status is transmitted through the ERFDAS (Emergency Response Facility Data Acquisition System) which provides the control room operator with a CRT display on the open or closed valve status for each of the main steam safety relief valves.

10.3.1.3 **Performance Analysis**

The steam generator repairs effected in 1979 and 1981 incorporated design features to eliminate various forms of tube degradation. The design features combined with inservice inspections will help ensure that tube integrity is maintained. The acceptability of the repaired steam generators is discussed in detail in a safety evaluation by the Office of Nuclear Reactor Regulation dated December 15, 1978 (Reference 2).

Design criteria for the steam generator lower assemblies require that tube vibration, tube fatigue, and tube support plate hole enlargement be within acceptable limits. As a result, flow-induced tube vibration caused by turbulence, fluid elastic excitation, and vortex shedding has been evaluated. The evaluation shows that the maximum alternating bending stress in a tube is 1.2 ksi. The code allowable number of cycles at this stress level is infinite and the fatigue usage factor is zero. Furthermore, the wear coefficient of SA-240 type 405 stainless steel, when paired with Inconel tubing at normal operating temperatures, is lower than that for carbon steel; therefore, initial tube clearances will be maintained and tube support conditions will not change noticeably during the lifetime of the steam generator.

If a main steam pipe rupture occurs, a flow signal measured by the venturi flowmeter located in that main steam line causes the swing check trip valves in all three main steam lines to trip closed. The trip valves are assumed to close within 10 seconds from the time the process variable reaches the trip setpoint. This time is comprised of three components: one second for the instrument response time delay from the time the setpoint is reached until bleed off of instrument air pressure is initiated, a maximum of 4 seconds to bleed off the instrument air pressure from the main steam trip valve operating cylinders, and a maximum of 5 seconds as closure time for the valve. If the rupture occurs downstream of the trip valves, valve closure stops the flow of steam through the pipe rupture, thus checking the sudden and large release of energy in the form of main steam. This prevents rapid cooling of the reactor coolant system and an ensuing positive reactivity insertion. Trip valve closure also ensures a supply of steam to the turbine drive for the steam-driven auxiliary feedwater pump described in Section 10.3.5.

If a steam line breaks between a trip valve and a steam generator, the affected steam generator continues to blow down. The nonreturn valve in the ruptured line prevents blowdown from the other steam generators. Steam-break accidents are discussed in Section 14.3.2.

10.3.1.4 **Secondary Plant All-Volatile Chemistry Treatment**

Phosphate chemistry was used prior to 1975, but both units changed to all-volatile treatment (AVT) in January 1975. A chemistry monitoring program has been implemented to inhibit steam generator tube degradation. Discussion of the monitoring system is provided in Section 9.6, Sampling System.

Condenser inleakage, contaminants from condensate polishing, and condensate/feedwater system corrosion products are the major sources of chemical agents that have the potential for accumulating as sludge on the steam generator tubesheet, producing deposits on steam generator heat transfer surfaces. The feedwater is the means by which these chemical agents are transported to the steam generator. AVT chemistry provides no buffer against the effects of condenser inleakage; it is incapable of preventing the formation of scale should the chemical agents that have the propensity for scale formation be present, and the ammonium hydroxide or the amines added to the system for feedwater pH control have minimum effectiveness as steam generator pH control agents at the operating temperature in the steam generator. Therefore, to accomplish the goal of maintaining the secondary system in an all-volatile chemistry environment that is innocuous to the steam generator materials, it is necessary to minimize the introduction of contaminants and corrosion products to the system. In addition to providing the proper environment for the steam generator, a well-maintained AVT chemistry program will accomplish the following:

1. Maintain the integrity of system components.
2. Minimize turbine deposits due to carryover from the steam generators.
3. Minimize sludge in the steam generators.
4. Minimize scale deposits on the steam generator heat transfer surfaces.
5. Minimize feedwater oxygen content prior to entry into the steam generators.
6. Minimize corrosion of the condensate/feedwater system materials.

7. Maintain chemistry near neutral in steam generator crevices.
8. Maintain desired dissolved oxygen level.

These objectives can be achieved by exercising chemistry control over the systems, including sampling and analysis, chemical injection at selected points, continuous system blowdown from the steam generator, and effective protection of the steam generator and feedwater train internals during periods of inactivity. The objectives are accomplished by meeting steam generator control parameters specified by the Nuclear Plant Chemistry Program. The specifications are based on the EPRI, PWR Secondary Water Chemistry Guidelines, including:

1. The use of approved amine(s) for feed water and steam pH control (ammonium hydroxide, morpholine, ethanolamine, and cyclohexylamine are acceptable).
2. The use of an approved oxygen scavenger in the feedwater train.
3. Continuous blowdown and continuous chemical addition.
4. Limiting the concentrations of contaminants in the feedwater and in the steam generator.

For corrosion prevention, the ingress of oxygen into the steam generators should be controlled. Oxygen should be less than 0.005 ppm in the blowdown under any operating or test condition. Oxygen is reduced by the addition of an oxygen scavenger. During hot standby, the concentration of oxygen in the feedwater can be 0.1 ppm or less, provided the concentration of oxygen scavenger injection into the steam generator is within recommended limits.

The concentration of oxygen scavenger in the steam generators during hydro and wet layup must be adequate to minimize dissolved oxygen and passivate the covered metal surfaces.

When controlling steam generator chemistry on AVT chemistry, it must be recognized that (1) AVT provides no buffering capacity for contaminants entering the steam generator, and (2) the steam generator bulk water pH is at or slightly in excess of the neutral pH for water at the operating temperature of the steam generator. The absence of alkalinity in the steam generator at its operating temperature is due to the low ionization of the feedwater pH control amines at these temperatures. Therefore, contaminants entering the steam generator that are more strongly ionized than the feedwater pH control amines have the potential for producing perturbations to the bulk water either in the form of free hydroxide (from fresh waters) or acidity (sea water or treated circulating water). The objectives of the steam generator chemistry control parameters are to provide a means for controlling the steam generator crevice chemistry to minimize corrosion of the steam generator and turbine cycle materials, and to provide a means whereby perturbations to the steam generator chemistry from sources such as condenser inleakage can be recognized.

In the recirculating steam generator, the only bulk water losses from the steam generator are the blowdown and the moisture that is entrained in the steam. Therefore, any contaminant entering the steam generator will tend to concentrate until corrective action is taken.

Based on the type of steam generator degradation that has been observed at pressurized water reactors (PWRs) cooled by seawater and brackish water, emphasis should also be placed on the control of sodium. Inconel 600 steam generator tubing is susceptible to caustic induced IGA/IGSCC, and because of this, every effort must be made to exclude free hydroxide from the steam generator environment. Operational control of the steam generator sodium to chloride molar ratio is recommended to achieve near-neutral chemistry in the steam generator crevices. The controlled addition of chloride may be warranted to counter excess sodium ions.

Protection of the steam generators during inactive periods due to maintenance and refueling requires placing the steam generators in a layup condition. To ensure the long-term performance of the steam system, the same degree of chemical control exercised during normal operation should be exercised during shutdown conditions.

Periods of hot shutdown and hot standby operation require that steam be released from the steam generators to release heat in the reactor coolant system due to heat input from reactor core decay heat and reactor coolant pump heat. Chemistry control is applied during such operations similar to that exercised during normal operating conditions.

Secondary-water chemistry specifications should be adhered to during all phases of unit operation. When specifications are exceeded, operator action is taken as recommended in the station’s chemistry control program.

10.3.1.5 **Tests and Inspections**

The turbine overspeed protection is checked during normal unit start-up. The steam dump system also functions during unit start-up. Operation of the steam generator power operated relief valves is checked at start-up and also periodically during normal operation.

The turbine-driven auxiliary feedwater pump is tested in accordance with the Technical Specifications.

Safety-related main steam components are tested in accordance with Technical Specifications.

During unit shutdown, the tripping mechanisms for the trip valves are tested for proper operation. The nonreturn valves are also tested to verify that they are functional.

10.3.2 Auxiliary Steam System

An auxiliary steam system is provided as shown in Figure 10.3-7 and Reference Drawings 2 and 3. All piping is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the auxiliary steam system was found to be adequate.

10.3.2.1 **Design Basis**

Steam from the secondary system is reduced in pressure and supplied to the auxiliary steam system for space heating, process system heat exchangers, and process system air ejectors. Nearly all secondary steam used in the auxiliary steam system is condensed, returned to the condensate system, and then sent to either the condensate storage tank or the main condenser. A small quantity of secondary steam used in the auxiliary steam system for the after condenser air ejectors and containment vacuum ejectors is not returned to the condensate system for reuse. Auxiliary steam used in the after-condenser air ejectors is condensed and drained to the storm sewage system or returned to the condenser. Auxiliary steam used in the containment vacuum ejectors is ejected to the atmosphere through the roof of the auxiliary building.

The auxiliary steam system supplies 150 psig saturated steam throughout the station for auxiliary services.

Turbine building uses of auxiliary steam are as follows:

1. Main condenser air ejector.
2. Space heating.
3. Gland seal steam.

Auxiliary building uses of auxiliary steam are as follows:

1. Boron recovery system heat exchangers.
2. Chemical and volume control system (boric acid batch tank heating).
3. Containment vacuum ejectors.
4. Space heating.

Auxiliary steam is used in the yard for the following purposes:

1. Boron recovery tank heating.
2. Primary-grade water tank heating.

Auxiliary steam is used for space heating in the following additional areas:

1. Fuel building.
2. Decontamination building.
3. Safeguards area.
4. Service building area.
   a. Shops.
   b. Mechanical equipment rooms 1 and 2.

c. Emergency generator rooms.

d. Boiler room.

The service building, including locker rooms, laboratories, offices, instrument shop, mechanical room, assembly room, and first-aid room are heated by steam coils in air-handling and air-conditioning units that serve these areas. All of these air-handling units are installed in the mechanical equipment rooms 1 and 2.

No auxiliary steam is used in the operations administration building. It is heated by hot water and steam-heated ventilation air. The hot water converter and the air-conditioning unit containing the steam coil for ventilation heating are installed in the turbine building.

10.3.2.2 **Description**

Normally, the auxiliary steam supply header receives its steam requirements from the second point extraction lines. During periods of low load operation when second point extraction steam pressure drops below approximately 140 psig, steam is supplied from the main steam header through a pressure-reducing valve. When both reactors are shut down, steam is supplied by the heating boilers.

The containment vacuum system steam ejectors are used only during start-up periods to initially evacuate the containment. During normal operation, two mechanical vacuum pumps maintain the vacuum, as described in Section 5.3.4.

Two heating boilers, each rated at 80,000 lb/hr of steam, are provided for preliminary and shutdown operation. Each boiler is the packaged water tube type and is equipped with motor-driven fuel-oil pumps, deaereator, and feedwater pumps. Number 2 fuel oil is supplied to the boilers from the main oil storage tanks.

10.3.2.3 **Performance Analysis**

A loss of normal ac power will shut down the heating boilers. No services supplied by auxiliary steam are required to function as part of engineered safeguards during a loss of station power.

10.3.2.4 **Tests and Inspections**

Routine inspections are performed on a periodic basis.

10.3.3 Turbine Generator

The turbine-generator heat balance for a bounding NSSS power of 2602 MWt is shown in Figures 10.2-1 through 10.2-4 and Reference Drawing 10.

10.3.3.1 **Turbine**

The turbine is a conventional 1800-rpm, tandem-compound unit (ALSTOM Retrofit), consisting of one single-flow high-pressure cylinder and two double-flow low-pressure cylinders. The high pressure turbine disks are 12% Cr-Mo-V and low pressure turbine disks are 2% Cr-Ni-Mo. Periodic inservice inspections are conducted to verify the integrity of the internal components of the turbines. An analysis of turbine missile risk is provided in Section 14.2.13. The inspections are conducted at a frequency consistent with the methodology specified in Reference 7. The inspection interval of the low pressure turbine blading is dictated by the Technical Requirements Manual.

The Unit 1 turbine is expected to achieve a maximum capability of 879.11 MWe gross with inlet steam condition of 769.5 psia and 0.25% moisture exhausting to 3.57 inch Hg (absolute) with feedwater temperature of 438.1 deg F and 0.0% makeup. The Unit 2 turbine is expected to achieve a maximum capability of 878.48 MWe gross with inlet steam conditions of 775.4 psia and 0.25% moisture exhausting to 3.56 inch Hg (absolute) with a feedwater temperature of 438.5°F and 0.0% makeup. The turbine is provided with six stages of feedwater heating and four moisture-separator reheaters located between the high-pressure and low-pressure cylinders.

Each high-pressure steam line to the high-pressure cylinder contains a stop-trip valve and a governor control valve. Stop valves and intercept valves are provided at the discharge of the moisture-separator reheaters to the low-pressure turbine cylinders.

A gland steam sealing system is provided to prevent air inleakage and steam outleakage along the turbine shaft. All necessary piping, controls, and a gland steam condenser are provided.

The turbine oil systems include a conventionally designed electro-hydraulic-controlled governing-trip system. There is also a low-pressure bearing lubrication system, discussed in Section 10.3.7.

Overspeed protection is provided through use of an overspeed trip mechanism that consists of an eccentric weight mounted in a transverse hole in the turbine rotor extension shaft. Centrifugal force moves the weight outward against spring compression. When the turbine overspeeds to a point at which the mechanism is set to operate, the spring compression is overcome by the centrifugal force of the rotor speed, and the weight moves out to strike a trigger, which trips the overspeed trip valve and releases the auto-stop oil and operating fluid to drain.

Additional turbine overspeed protection utilizes the output of magnetic pickups mounted adjacent to the turbine shaft. A toothed wheel on the shaft provides a fluctuation magnetic coupling for the speed transducer pickups. The speed transducer senses fluctuations and translates them into a sine wave whose frequency is proportional to turbine speed. This signal is fed to the auxiliary governor. If the control subsystem senses an overspeed condition (103% speed), and the generator is not in parallel with the grid or if electrical output is less than 5%, then the auxiliary governor provides a control signal to SOVs in the EHC subsystem which depressurizes the governor valve emergency trip header. This trips the governor and intercept valves closed while the overspeed signal is present in an attempt to limit the overspeed and prevent an overspeed trip. Once the turbine speed decreases below 103% of rated speed, the solenoids close and the intercept valves start to reopen immediately followed by the governor valves after five seconds. When the generator is in parallel with the grid and electrical output is greater than 5% then the auxiliary governor's overspeed function is disabled. This is because this protection is not needed when these conditions are met due to the fact that synchronous generators in parallel must operate at grid frequency and physically can not overspeed.

The Reverse Power protection system provides two forms of turbine protection. Excessive heat damage to the turbine is prevented during generator motoring by tripping the generator breakers 40 seconds after sensing the reverse power condition. Additional turbine overspeed protection is provided by using the reverse power relay to provide sequential tripping.

Sequential tripping is the inclusion of a reverse power relay in series with any trip circuits using steam valve close position switches. This will provide security against possible overspeed by ensuring that all sources of steam to the turbine are reduced below the amount required to produce overspeed before the generator breakers and excitation breakers are tripped. In addition, the reverse power relay provides a time delayed backup trip in the case of failed or misadjusted valve position switches.

This protection will not override the generator or switchyard protection that instantaneously opens the generator breaker when an electrical fault occurs that might cause serious and certain damage to the generator or switchyard equipment.

10.3.3.2 **Generator**

The hydrogen inner-cooled generator rating is 1,055,000 kVA at 75 psig hydrogen gas pressure, 0.90 pf, three-phase, 60 Hz, 22 kV, and 1800 rpm. The Unit 1 generator has a 0.540 SCR, while the Unit 2 generator has a 0.559 SCR. The Unit 1 and Unit 2 generator will be operated in accordance with their respective capability curves from the station curve book. The capability curves show the generator capacity for various combinations of power factor and hydrogen pressure.

Primary protection of the main generator is provided by differential current and field failure relays. Protective relays automatically trip the turbine stop valves and electrically isolate the generator.

A rotating rectifier (brushless) exciter with a response ratio of 0.5 is provided for both units. The exciter rating is 4700 kW, 570V dc, and 1800 rpm. The exciter consists of an ac alternator coupled directly to the generator rotor. The alternator field winding is stationary, and control of the exciter is applied to this winding. The alternator armature output is rectified by banks of diodes that rotate with the armature. This direct current output is carried through a hollow section of the shaft and is applied directly to the main generator field.

The 22-kV generator terminals are connected to the main step-up transformer and the unit station service transformers by 22-kV aluminum conductors, each rated at 29,500A. Each aluminum conductor is enclosed in a self-cooled, isolated-phase bus duct. Further discussion of the interconnection between the generator and the transmission system is contained in Section 8.3.

Hydrogen seal-oil pumps are furnished to provide seal oil to the generator shaft seals for the prevention of hydrogen leakage from the generator. An ac motor-driven high-pressure hydrogen seal-oil back-up pump and a dc motor-driven, air side seal-oil backup pump are provided. A continuous bypass-type oil purification system removes water and other contaminants from the oil.

Since a mixture of hydrogen and air is explosive over a wide range of proportions (from about 4 to 70% hydrogen by volume), the design of the generator and the specified operating procedures are such that explosive mixtures are not possible under normal operating conditions. In order to provide for some unforeseen condition brought about by the failure to follow the correct operating procedure, it is necessary to design the frame to be explosion-safe. The intensity of an explosion of a mixture of air and hydrogen varies with the proportions of the two gases present. A curve on which the values of intensity are plotted against the proportions of gases will approximate a sine wave, having zero values at 5 and 70% hydrogen and reaching a maximum intensity at a point half way between these limits. The term “explosion-safe” is intended to mean that the frame will withstand an explosion of this most explosive proportion of hydrogen and air at a nominal gas pressure of 2 or 3 psig without damage to life or property external to the machine. This nominal pressure of 2 or 3 psig is that which might be obtained if hydrogen were accidently admitted during the purging operation instead of carbon dioxide, as specified. Such an explosion might, however, result in damage or dislocation of internal parts of the generator. When changing from one gas to another, the generator is vented to the atmosphere, so that a positive pressure of more than 2 or 3 psig will not be built up.

10.3.4 Circulating Water System

The circulating water system, Reference Drawing 4, provides cooling water for the main condensers and the service water systems of both units. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the circulating water system was found to be adequate.

10.3.4.1 **Design Basis**

To prevent the direct recirculation of the heated circulating water discharge, the system is designed to take water from the James River on the east end of the site and to discharge to the James River on the west end of the site. The shoreline distance between the intake and discharge points is about 5.7 miles, and the overland distance across the peninsula is about 1.9 miles.

Each unit requires 840,000 gpm of river water to supply condensing and service water needs. To provide operational flexibility, system reliability, and station economy, the water requirement for each unit is supplied by four 220,000-gpm pumps. These pumps discharge to the common high-level intake canal that conveys the circulating water to the station area. Coarse trash is removed from the circulating water by trash racks at the river intake structure, and finer trash is removed at the river intake and at the entry-bay and station ends of the intake canal by two sets of traveling water screens. The circulating water flows by gravity from the high-level intake canal through four buried parallel lines to each condenser and then through four separate lines to a concrete tunnel for each unit. The tunnels terminate at seal pits located at the edge of the circulating water discharge canal, which is common to both units.

The discharge canal conveys the flow to the James River. The discharge channel within the river is provided with rock groins along each side to control sedimentation and to maintain exit velocities of the circulating water to achieve desired dilution effects of the heated effluent.

Some components of the circulating water system are used for handling service water, and are therefore designed as Seismic Category I structures and components. These components are:

1. The circulating water intake structure at the river.
2. High-level intake canal.
3. High-level intake structure.
4. Buried circulating water piping and valves between the high-level intake canal and the circulating water discharge tunnel.
5. Circulating water discharge tunnel.
6. Seal pits.
7. Intake canal low-level isolation level switches (1-CW-LS-102 & 103, 2-CW-LS-202 & 203).

10.3.4.2 **Description**

The circulating water is withdrawn from the James River through a channel dredged in the river bed. The original channel invert was 150 feet wide at Elevation -13.3 ft. It extended a distance of approximately 5000 feet to the main river channel. A natural river channel bisects the dredged channel approximately 2000 feet from the shore. This inner portion of the dredged channel is periodically monitored and dredged as necessary to support plant operations. The combination of the natural channel and the dredged channel is also used for shipping materials and equipment to the permanent dock on the east side of the site.

The circulating water intake structure is located at the shore end of the river intake channel and is an eight-bay reinforced-concrete structure. The exposed deck of the structure is at Elevation +12 ft. The invert of the intake structure is at -25.25 feet. Each bay houses one of the eight circulating water pumps for the two units. These pumps are rated 220,000 gpm at 28 feet total dynamic head when running at 220 rpm. Each pump is driven by a vertical, solid-shaft, 2000-hp, induction motor. The pumps are of the nonpullout type and are serviced using mobile hoisting equipment. Before entering the pumps, river water passes through a trash rack and travelling screen at the mouth of each bay. The travelling screens are provided with deflector flaps and screenwash pumps for low-pressure water spray. The deflector flaps ensure that fish dumped from the screens are deflected into a trough for transport via an effluent flume back to the James River. The low pressure spray ensures more efficient washing of fish from the screens into the fish collector trough. The trash rack is serviced by a movable trash rack rake that discharges collected trash to a receptacle where it accumulates until trucked off-site for disposal. In the event of a power failure, accumulated trash can be removed by manual raking. This process could continue indefinitely; however, it is expected that any power failure at the station low-level intake would be of relatively short duration.

Each circulating water pump discharge line is a 96-inch diameter steel pipe that conveys the water over the embankment of and into the high-level intake canal. At the crest of the canal embankment, the crown of the pipe is provided with a pair of active vacuum breakers (valves) and a tap for the vacuum priming system. The vacuum priming system prevents air accumulation in the pump discharge line while the pump is operating. This system is isolated when the circulating water pumps are de-energized. The active vacuum breakers open when the circulating water pump is de-energized. These vacuum breakers prevent loss of water from the high-level intake canal by siphoning through idle pumps. A passive vacuum breaker, designed to conserve intake canal water in the event of a failure of the paired active vacuum breaker valves, is located on the discharge end of each 96-inch diameter pipe. The passive vacuum breaker consists of a 20-inch diameter low profile vertical pipe protection which extends to Elevation +25 ft. of the intake canal. The passive vacuum breakers are designed to interrupt the postulated siphon action prior to reaching the technical specification limitation for canal water level.

The high-level intake canal is about 1.7 miles long and is designed to convey the circulating water flow to the station. The canal is paved with 4.5 inches of reinforced concrete, to allow velocities that would otherwise erode the earthen materials through which the canal is constructed. Since these earthen materials have low permeabilities, significant loss of water through the canal lining and into the substrata is not considered probable. The bottom width along most of the length of the canal is 32 feet, and the canal has side slopes of 1.5 feet horizontal to 1 foot vertical. The invert elevation varies from Elevation +5 ft. at the station end of the canal to Elevation +6.8 ft. at the river end of the canal. The berm along each bank of the canal is at Elevation +36 ft.

The water levels in the canal are controlled by the piping system friction losses within the power station and the prevailing river level. The normal water elevation at the power station end of the canal will vary between Elevation +26 ft. and Elevation +30 ft., depending upon the tide. A minimum freeboard greater than four feet is maintained between the canal water surface and the berm at Elevation +36 ft. during hurricane flooding of the river. This freeboard is adequate to contain surges in the canal that could occur with a loss of station power when the river is in flood and is maintained by progressively reducing the number of pumps in operation by manual control as the James River rises above Elevation +5 ft.

A reinforced-concrete, high-level intake structure is provided in the high-level intake canal at each power station unit. Each structure contains four bays, and each bay contains a trash rack, a traveling screen, and an inlet to a 96-inch-diameter condenser intake line. Steel plates can be placed on the stop log supports to permit dewatering of individual bays of the structure. Screenwash water is supplied by two pumps, each rated at 850 gpm at a 220-feet TDH.

Level sensors (1-CW-LE-102 & 103, 2-CW-LE-202 & 203) are installed in four of the screenwell bays (B & D for Unit 1 and A & C for Unit 2) between the trash rack bars and the travelling screens. Each sensor is positioned at Elevation 23-ft. 6-in. and will initiate a low level isolation channel assigned to two independent trains of 3-out-of-4 actuation logic when the canal level decreases to or below that elevation.

The four 96-inch diameter lines connecting the condenser and the high level intake structure are reinforced concrete in the station yard and welded steel encased in concrete under the station. Service water system taps are made in the steel portion of these lines.

Electric motor-operated butterfly valves are provided at the condenser inlets and outlets. The discharge lines terminate at the reinforced-concrete discharge tunnel, which then carries the water to the common circulating water discharge canal. This tunnel is 12 ft. 6 in. by 12 ft. 6 in. in cross section. The circulating water system total energy gradient in the discharge system is maintained at proper elevation to ensure a full condenser discharge water box by a seal weir at the termination of the discharge tunnel.

On each unit’s discharge tunnel, upstream of the vacuum priming house, is a 12-inch manually operated butterfly valve which is no longer used and has been abandoned in place.

The discharge canal is excavated in earth and is designed to carry the flow of the two units with a velocity of about 2.2 fps at mean low water. The invert of the canal is at Elevation -17.5 ft. and the sides slope at 2 feet horizontal to 1 foot vertical; this slope is stable under the design basis earthquake condition. The bottom width of the canal varies between 20 feet and 65 feet.

The discharge canal extends about 1200 feet into the James River. This extension has rock-filled groins along each side to minimize siltation. The opening between the groins is sized to ensure proper mixing of the discharge water with the James River. A timber pile trestle having five 10-foot-wide bays in which timber gates may be placed extends about half-way across the opening in the groin. The timber gates may be installed in this structure using mobile hoisting equipment to reduce the net area of the opening between groins and increase terminal flow velocity if determined necessary. Since terminal flow velocity is no longer considered a necessary parameter for thermal effluent control and is not required in the existing VPDES permit, the timber gate feature has effectively been abandoned in place.

10.3.4.3 **Performance Analysis**

All four circulating water pumps for each unit should normally be in service. If a circulating water pump is out of service, unit operation can be continued, but the station operator must maintain a satisfactory water level in the high-level intake canal by throttling the condenser outlet valves.

The condenser inlet and outlet valves are normally controlled from the control room. When a consequence-limiting safeguard-initiation occurs and there is a loss of station power, both inlet and outlet valves receive automatic close signals so that if one fails to close, the other will close. The valves are closed to conserve water in the high-level intake canal for cooling the recirculation spray heat exchangers. When a loss of power occurs without a consequence-limiting safeguard initiation signal, the condenser outlet valves are throttled to conserve water in the intake canal for the bearing cooling heat exchangers and component cooling heat exchangers, and to provide a minimum flow required by the steam dump system. If the water level in the high-level intake canal drops to Elevation 23-ft. 6-in., both the condenser inlet and outlet valves are closed to conserve water in the high-level intake canal for subsequent use. Two air-operated vacuum breaker valves are mounted on each condenser outlet waterbox at the highest point in the circulating water system. These valves are designed to interrupt the siphon action of circulating water flowing through the condenser and conserve intake canal water during a postulated Appendix ‘R’ event which prevents closure of the condenser inlet and outlet valves. As mentioned in Section 10.3.4.1, certain components of the circulating water system are designed as Seismic Category I structures to preclude system failure during an earthquake, and are also designed to withstand a tornado in order to ensure a supply of service water in the event of an accident. The traveling water screens have been sized to prevent trash from plugging critical heat exchangers in the service water system.

Automatic operation of the condenser inlet and outlet valves and the valves in the service water system under various accident or event conditions are listed in Table 9.9-1.

A single-ended rupture of one of the 96-inch diameter main circulating water system lines upstream of the condenser isolation valve will not lead to unacceptable consequences. Within the turbine and service building, the postulated break could only occur at Elevation 5 ft. 6 in. in the valve pit in front of the condensers. In this area, the 96-inch diameter steel pipes are exposed above the concrete encasement for a height of approximately 28 inches. A 96-inch-diameter motor-operated isolation valve and an expansion joint connect this section of the pipe directly to the condenser. The pipelines in question have been analyzed to ensure that failure will not occur as a result of a design-basis earthquake.

The circulating water pipe enters the turbine building through a concrete pipe chase. As it nears the main condenser it makes a 90-degree turn upward and exits the concrete pipe chase adjacent to the main condenser. After the motor-operated isolation valve and expansion joint, the pipe immediately takes a 90-degree turn to the main condenser water box. A break in the circulating water pipe that would permit the equivalent flow of a complete single-ended rupture into the turbine building is not credible. The pipe chase confines the movement of the pipe below the valve, the valve permits stopping flow if the break is after the valve, and the short run of exposed pipe after leaving the pipe chase prohibits side movement of the pipe to clear the break and permit full unrestricted flow.

Because of these restraints on the movement of the circulating water piping, it is not considered likely that a crack will develop in the approximate 28-inch section of exposed pipe. In the unlikely event that a crack as wide as 1/8 inch developed around as much as one half of the circumference of the pipe, the flow through the crack would be approximately 2000 gpm, which would not exceed the capacity of the turbine building floor drain sump pumps. There are three floor drain sumps for both units, each equipped with three pumps rated at 1300-gpm, for an individual sump rated capacity of 3900 gpm.

Stop logs at the inlet end of the intake structure are employed to seal off the circulating water lines upstream from the isolation valves. Long-term cooling water canal integrity provided by installing these stop logs ensures a continued ability to remove decay heat.

There are separate takeoffs from two of the four circulating water lines to supply service water to the equipment needed during an emergency.

Isolation of one of the circulating water lines containing these connections would not result in interruption of emergency service water supply.

Two 300-gpm submersible makeup water pumps for the Gravel Neck Facility have been installed in the intake canal. The supports for these pumps have been designed so that the pumps cannot take suction below the minimum canal level in Technical Specifications. This ensures that design basis calculations for canal level drawdown following a loss of offsite power, are not affected by makeup pump operation. Since these makeup pumps are only rated at 300 gpm, they have an insignificant impact on total circulating water flow during normal station operation.

Automatic operation of the condenser and service water motor-operated valves, as described in Table 9.9-1, are checked during initial operation and at frequent intervals thereafter.

Intake canal level instrumentation calibration and alarm setpoints are checked periodically. The level sensor channels and logic trains are calibrated and tested in accordance with the Technical Specifications.

10.3.5 Condensate and Feedwater Systems

The condensate and feedwater systems are shown on Figures 10.3-8 and 10.3-9 and Reference Drawings 5 and 6, and the heat balance used for station design is shown on Figures 10.2-1 through 10.2-4 and Reference Drawing 10. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the following systems were found to be adequate: condensate system, feedwater system, feedwater heaters, moisture separator and high pressure heater drain system, low pressure heater drain system and the extraction steam system.

10.3.5.1 **Design Basis**

The condenser hotwell is designed to operate at a normal level such that about 4 minutes of condensate flow is available to supply the condensate pumps. A 300,000-gallon condensate storage tank floats on the system. Each of the three vertical barrel-type condensate pumps is rated at 9000 gpm and 1070 feet TDH. Minimum flow through the pumps and gland steam condenser is maintained by an orifice-measuring device downstream of the gland steam condenser. The orifice-measuring device operates the recirculation valve.

Two steam generator feedwater pumps, each rated at 13,800 gpm and 1700 feet TDH, are furnished to supply feedwater to the three steam generators. Each feedwater pump is equipped with two electric motor drivers in tandem. Minimum flow through each pump is maintained by flow nozzles in the discharge lines. The recirculation valve opens when the flow drops to 4300 gpm.

A turbine-driven auxiliary feedwater pump, rated at 700 gpm and 2730 feet TDH, and two motor-driven auxiliary feedwater pumps, rated at 350 gpm and 2730 feet TDH, receive suction from a separate 110,000-gallon-capacity emergency condensate storage tank. The feedwater pumps are located outside the containment in a tornado-missile-protected enclosure near the main steam line and feedwater line containment penetration. The emergency condensate storage tank is also tornado missile protected, as is the suction piping leading from the storage tank to the pumps. The system design is based on the following conditions:

1. Integrated residual heat release from a full-power equilibrium core.
2. Feedwater inventory of the steam generators operating at normal minimum feedwater level.
3. Minimum allowable steam generator feedwater level permitted to prevent thermal shock or other damage.
4. The temperature of the feedwater that is supplied from the condensate storage tank. This temperature was assumed as 32°F when considering thermal shock, and 120°F when considering feedwater enthalpy.

The auxiliary feedwater system has been designed, constructed, and maintained to withstand a design-basis earthquake, utilizing methods and acceptance criteria consistent with those applicable to other safety-grade systems in the plant. All areas of the auxiliary feedwater system (i.e., pumps/motors, piping, valves/actuators, power supplies, water sources, instrumentation and control systems, and structures having and supporting the auxiliary feedwater system) are seismically qualified to the design-basis earthquake level.

The pump discharge piping of the auxiliary feedwater systems installed in Units 1 and 2 is cross-connected to ensure that, in the event of a postulated high energy line break in the Main

Steam Valve House or a fire that disables the auxiliary feedwater pumps, the unaffected system will have the ability of maintaining both units in a shutdown condition. The cross-connect line originates downstream of each unit's auxiliary feed pump discharge valve on the auxiliary feed system two main branch lines. Motor-operated valves are installed on each of the two cross-connect branches to provide remote control. A manual valve upstream of the motor-operated valves provides manual control of that specific branch of the cross-connected feed system.

The pumps, drives, piping, and 110,000-gallon emergency condensate storage tank have all been designed as Seismic Category I components (Section 15.2.1).

10.3.5.2 **Description**

The condensate and feedwater systems are shown on Figures 10.3-8 and 10.3-9 and Reference Drawings 5 and 6. Condensate is withdrawn from the condenser hotwells by two of the three half-size motor-driven condensate pumps. The pumps discharge into a common 24-inch header and then through a 24-inch manually operated gate isolation valve to the condensate polishing building. There the water is purified and sent back through another 24-inch manually operated gate isolation valve to the condensate header. From there the condensate continues through two parallel steam jet ejector condensers and through one gland steam condenser. A 24-inch motor-operated gate valve allows for bypassing the gate isolation valves when the system is not in use. The common header divides into two 18-inch lines that carry condensate through a pair of heater drain coolers and the tube side of two parallel trains of five low-pressure feedwater heaters to the suction of two half-size steam generator feedwater pumps. The steam generator feedwater pumps discharge through two parallel No. 1 feedwater heaters to an 18-inch discharge header for distribution to the steam generators through three individual feedwater flow control valves, positioned by the three-element feedwater control system for each steam generator. A remotely operated small bypass valve is provided in parallel with each of the feedwater flow control valves for manual control of feedwater flow to maintain steam generator levels, primarily during low-power operation or hot shutdown. Each bypass line has the capability to provide flow rate indication when aligned to the branch connection downstream of its associated feedwater flow venturi (see Figure 10.3-9). An ultrasonic flow meter is installed in each of the feed water lines of the steam generator feedwater system. The ultrasonic flow meter system measures feedwater flow, feedwater temperature, and UFM localized feedwater pressure information for input into the secondary calorimetric calculation (see Figure 10.3-9).

Drains from the moisture-separators, reheaters, and the No. 1 and No. 2 feedwater heaters are collected in the high-pressure heater drain tank and pumped into the suction of the steam generator feedwater pumps by one of two full-size high-pressure feedwater heater drain pumps.

The principal controls of the condensate and feedwater systems are located in the control room. The system is arranged for automatic or manual control.

Impure condensate in the condenser hotwells is either routed to a condensate polishing system, where it is purified and reused, or is discharged under administrative control through a double-valve connection to the circulating water discharge canal. The double-valved connection with telltale drain prevents inadvertent releases. Planned releases of hotwell condensate to the discharge canal are infrequent, since they are needed only when there has been a major upset in condensate-feedwater chemistry. The condensate is manually sampled to determine if activity levels will permit a safe release. Blowdown line sampling and monitoring is conducted during such releases to ensure that an increase in condensate activity is detected in sufficient time to permit operator action to avoid an uncontrolled release of radionuclides to the environment. Additional indication is provided by radiation monitors installed at the seal pit of the circulating water discharge tunnel.

Two condensate storage tanks, one per unit, are provided for makeup and can be cross connected if necessary. The amount of makeup is controlled by low hotwell level. A recirculation control to the hotwell returns condensate at low generator loads and provides the minimum amount of water for the air ejector condensers and the gland steam condenser. In an emergency, backup water for fire protection can be obtained from the condensate storage tanks.

A condensate cleanup line allows cleaning of the condensate piping and components prior to unit start-up. The condensate pumps can be used to recirculate condensate through the entire condensate system up to the suction of the main feed pumps, through the cleanup line, and back to the condenser hotwell. The condensate is cleaned by filtration through the condensate polishing system demineralizers.

A mixed-bed full-flow condensate polishing system removes dissolved salts and suspended solids from the condensate system. Design and operating information are given in Table 10.3-2.

Each unit's condensate polishing system consists of an independent set of condensate demineralizers supplied from the main condensate header downstream of the condensate pumps. Each set consists of seven demineralizers (six on-line, one spare) with each demineralizer containing mixed resins of cation resin and anion resin. As condensate passes through the resin, impurities are removed by interaction with the resin beads or by the filtration action of the overall resin bed. Each demineralizer discharge then passes through a resin trap, which prevents resin from entering the condensate stream, to an effluent header for return to the condensate system. At the inlet to each trap, an instrumentation penetration supplies a sample source to individual conductivity cells and to local sample valves. A sample is taken before a demineralizer is allowed to supply the condensate stream.

Demineralizer resin is transferred to an external regeneration system for separation and chemical regeneration. Each unit has an independent regeneration system consisting of a separator, separator feed tank, cation regeneration tank, an anion regeneration tank, and a resin mix tank. Air for resin transfer operations is supplied at 40 psig and 100 psig from the service air header of the instrument and service air system. Interlocks are provided to prevent inadvertent operations of influent and effluent valves during resin transfer operations.

Following regeneration, the anion and cation resin is transferred to a resin mix tank in preparation for its eventual return to the condensate demineralizers. Wastes generated by the regeneration process are treated and discharged by the waste neutralization system. Waste is discharged to the settling pond or to the discharge tunnel, and is discharged via waste filters if radiation is present. The waste filters may be bypassed if the total suspended solids have been analyzed to be less than the limits provided in the VPDES permit. Demineralizer and waste systems are remotely controlled from control panels in the condensate polishing building, which is located at the east end of the Unit 2 turbine building.

Condensate polishing system instrumentation is provided to monitor level, pressure, temperature, and flow parameters. This information allows for manual or automatic operation of the system. The instrumentation is tested in accordance with station requirements for existing Category II instrumentation.

Fire protection measures associated with the condensate polishing building are described in Chapter 9. Normal and emergency lighting is provided in the condensate polishing building.

Chemical feed equipment (Figure 10.3-10 and Reference Drawing 7) is provided for chemical treatment of feedwater based on the AVT concept. Hydrazine is added to control residual oxygen content. Ammonium hydroxide, morpholine, ethanolamine, or cyclo-hexylamine can be added to maintain an elevated pH. These chemicals act as corrosion inhibitors to reduce pickup of metal by the feedwater. Solutions are pumped into the main condensate and steam generator recirculation and transfer systems by motor-driven, positive-displacement pumps with manually adjustable strokes. If AFW is used to supply the steam generators during startup of the Unit, Carbohydrazide as well as Hydrazine may be used to control residual oxygen. In this situation, temporary chemical feed equipment may be used to treat the main steam condenser hotwell and inject Hydrazine into the suction of the AFW pumps.

An air in-leakage subsystem is provided to allow accurate establishment and monitoring of air bleed rates into the Condensate (CN) System. It has been determined that having dissolved oxygen (DO) in the CN system facilitates the formation of a passive corrosion layer on wetted secondary piping surfaces. This passive corrosion layer inhibits pipe-wall thinning and iron transport to the steam generators. This is accomplished by allowing air to be vacuum bled into Main CN Pump suction piping through flow controlling/measuring equipment.

An auxiliary steam turbine-driven feedwater pump supplies feedwater to the steam generators during a complete loss of station power. During periods of start-up, and for core residual heat removal, two auxiliary feedwater pumps, driven by electric motors connected to the station emergency busses, can be used.

Each of the three pumps discharges into two headers, aligned by manual valves. There are three lines from each header. Each line has a motor-operated valve with a downstream stop-check valve located inside containment. The lines join downstream of the stop-check valves and form a common discharge to supply each steam generator via the associated main feed line. Check valves in the main feedwater lines prevent loss of auxiliary feedwater should a main feedwater line rupture outside containment. The common discharge line to each steam generator has a cavitating venturi installed to restrict flow to the steam generator in the event of a ruptured steam line. A strainer is also installed upstream of each cavitating venturi to prevent blockage of the venturi throat by debris. In the event of failure of one header, the supplies from the pumps may be isolated by manually operated valves to ensure steam generator water flow from the other header. The motor-operated valves required to establish a flow path from the discharge of these pumps to the steam generators are configured such that AFW Flow path to one of the steam generators shall be limited with the plant between 350 degrees F/450 psig and Hot Shutdown (HSD). Under this configuration, two AFW MOVs (same steam generator) will be procedurally controlled with their Auto-open circuit defeated via operator controlled selector switches between 350 degrees F/450 psig and 535 degrees F and will be procedurally opened prior to Hot Shutdown. This alignment ensures that the turbine driven and motor driven pumps are not damaged by an unanalyzed high flow and potentially inadequate Net Positive Suction Head available (NPSHa) margin condition when a single AFW pump was delivering flow to three low pressure steam generators. The discharge valves fail as-is. Steam generator level is controlled manually from either the control room or the auxiliary shutdown panel by operating the appropriate motor-operated valve in the auxiliary feedwater line. During startup of the Unit using AFW, the AFW MOVs may remain in the partially throttled position up to and including Hot Zero Power (HZP). The throttling is controlled by procedure. Two (2) of the AFW MOVs have been modified to include 1-hour fire rated control cable between the Motor Control Center, Transfer Relay Cabinet, and Main Control Room. This as well as procedure controls ensures at least one MOV is maintained open for safe shutdown during an Appendix R Fire event.

The steam for the steam-driven auxiliary feedwater pump is supplied from the three main steam lines upstream of the main steam trip valves. Check valves in the steam supply lines prevent steam from flowing into a ruptured main steam line so that an adequate supply of steam will reach the turbine for the steam-driven pump. This steam enters the turbine-driven pump through two parallel air operated valves. These parallel air operated valves are controlled by double acting piston actuators that normally hold the valves closed. On a loss-of-power to the air supply solenoid, the pneumatic double acting piston actuator fails the valves open. A bottled nitrogen system is installed to provide control of the air operated valves for a minimum of 2 hours independent of instrument air.

The auxiliary feedwater system discharge lines of both units are cross connected but are isolated by normally closed motor-operated valves. Operator action will permit the auxiliary feedwater system of one unit to supply water to the steam generators of the other unit. These motor-operated valves are remote manual valves and require operator action to open. They are powered from an emergency bus and are controlled manually from the control room. Check valves are installed in each of the two cross-connect branch lines to the respective auxiliary feedwater header inside each containment to maintain the redundancy of these headers.

Each pump is provided with a full flow recirculation line to facilitate pump periodic testing. The return flow path to the emergency condensate storage tank is normally isolated by two valves in series, with valve position controlled by the plant operating procedures. The full flow recirculation may also be used during unit startup if AFW is used to feed the steam generators.

Permanent BDB piping connections exist on the AFW pump discharge headers. These normally isolated piping connections allow for a portable pump to inject water into the SGs during a beyond design basis event. A permanent BDB piping connection also exists on the suction line from the ECST to the TDAFW pump. This normally isolated piping connection allows for a portable pump to either refill the ECST or utilize the ECST as a suction source, based on the configuration of the pump, during a beyond design basis external event (BDBEE).

10.3.5.3 **Performance Analysis**

The auxiliary feedwater system, as described below, is the portion of the condensate and feedwater systems required for certain accident scenarios. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the auxiliary feedwater system was found to be adequate.

The auxiliary feedwater system is designed as a safety-related system except for the initiating signals of the reactor coolant buses undervoltage feature, the main feedwater pump breaker trip feature, the loss of reserve station power feature, and the AMSAC feature. The initiating circuitry incorporates both automatic and manual system start capability, including manual initiation of the system from the control room. Manual initiation capability is provided independent of automatic initiation, and the design of the automatic safety-related initiation circuitry is such that a single failure cannot result in total loss of the system function. The design of the safety-related portions of the auxiliary feedwater systems incorporates testability, and the system is powered from reliable emergency buses as specified in NUREG-0578, including automatic actuation of ac motor-driven pumps and valve loads onto the emergency buses. Although the MOVs feeding the Steam Generators are powered from the emergency buses, the automatic actuation feature for these valves for one Steam Generator is able to be defeated thru operator controlled selector switches. The position and automatic actuation features of these MOVs are procedurally controlled to ensure proper AFW system operation.

The auxiliary feedwater system consists principally of a turbine-driven auxiliary feedwater pump rated for 700 gpm, two motor-driven auxiliary feedwater pumps rated for 350 gpm, a 110,000-gallon storage tank, and associated piping, valves, and controls. The turbine-driven pump and the electrically-driven pumps represent two diverse pumping systems that operate automatically to supply auxiliary feedwater to the steam generator.

The turbine-driven auxiliary feedwater pump can be used for residual heat dissipation as long as adequate main steam is available. The steam supply lines to the turbine are continuously under main steam pressure to keep them warm and to prevent the formation of water droplets on turbine start-up. Steam traps are provided in lines to ensure that any condensate formed as a result of cooling is removed; however, the turbine is a single-inlet, single-stage unit, and any drops of water forming will not damage or impair its operation.

When main steam pressure is no longer adequate to provide sufficient cooldown, the need for residual heat removal has also been reduced to a level where one of the motor-driven auxiliary feedwater pumps can be used as necessary. The motor-driven pumps are powered from the 4160V emergency buses.

A reduction in the capability of the secondary system to remove the heat generated in the reactor core occurs if a loss of normal feedwater flow (LONF) condition exists. Section 14.2.11, Loss of Normal Feedwater, contains an evaluation of this event for cases with and without the reactor coolant pumps operating and a conservative core residual heat generation. If this event occurs, a reactor trip signal is generated due to a low-low steam generator level. To prevent water relief from the pressurizer and to ensure long-term decay heat removal subsequent to the reactor trip, adequate auxiliary feedwater flow is required. This is provided by use of either the turbine-driven or motor driven auxiliary feedwater pumps. The required amount of auxiliary feedwater depends on the status of the reactor coolant pumps and the core residual heat generation. With the reactor coolant pumps operating, more heat is added to the reactor coolant system which requires slightly more auxiliary feedwater for heat removal. The decay heat in current LONF analyses is based on 100% of the ANS 1979 Decay Heat Standard with 2-sigma uncertainty. Both types of auxiliary feedwater pumps are designed to start within 1 minute, even if a loss of offsite ac power occurs simultaneously with a loss of normal feedwater flow. These pumps ensure that there is adequate capacity to cool down the reactor.

Each unit's auxiliary feedwater pumps take suction from a tornado and missile protected 110,000-gallon emergency condensate storage tank (ECST), which is maintained above 96,000 gallons during unit operation. Each ECST (1/2-CN-TK-1) has redundant level indicators that provide for safety-grade indication, and alarming functions associated with tank level. The transmitters are seismically qualified, and are powered from a safety-related Class 1E vital bus. These components are not subject to harsh environmental conditions. Control room indication is provided with alarms set at or above the minimum Technical Specification limit of 96,000 gallons for tank level and also at a lower level to indicate when there is a 20-minute water supply remaining for the highest volume auxiliary feedwater pump.

Operation of the auxiliary feedwater pumps provides residual heat removal capability for up to 8 hours using the ECST. Each unit also has a non-safety-related emergency condensate makeup subsystem, consisting of a 100,000-gallon in-ground emergency condensate makeup tank (1/2-CN-TK-3) with auxiliary feedwater booster pumps, which can supply additional feedwater for additional heat removal capability. In addition, for Appendix R and environmental qualification considerations, both unit's auxiliary feedwater pumps are cross-connected at the pump discharge. Each unit's ECST is maintained above 60,000 gallons to support cross-tie capability for the opposite unit. An emergency source for necessary feedwater is the fire protection system. The three auxiliary feedwater pumps with redundant means of motive power and associated piping are installed in a tornado-protected area adjacent to the containment so that their use can be relied upon during any loss-of-station power accident.

The automatic initiation signals and circuits for the auxiliary feedwater system comply with the single-failure criterion of IEEE Standard 279-1971, with exceptions. The following signals are used for automatic initiation of the auxiliary feedwater system:

1. Turbine-driven auxiliary feed pump
    a. Low-low steam generator level (two out of three)
    b. Undervoltage on the reactor coolant pump buses (two out of three)
    c. AMSAC initiation
2. Motor-driven auxiliary feed pumps
    a. Low-low level from any one steam generator
    b. Loss of reserve station power (station blackout)
    c. Trip of both main feedwater pumps
    d. Safety injection
    e. AMSAC initiation

The steam generator level signals and the input signals from the safety injection system are both redundant and independent. Undervoltage on the reactor coolant pump buses, main feed pump breaker trip, and loss of reserve station power are considered operational signals for economic (non-public safety) protection and are therefore not required to meet the single failure criterion of IEEE Standard 279-1971.

The AMSAC signal is provided as a means, diverse from the reactor protection system, to automatically initiate the auxiliary feedwater system. This back-up signal was provided in accordance with the requirements of 10 CFR 50.62. The AMSAC logic circuit power supplies are normally powered from non-safety related sources independent of the RPS and are capable of operating on a loss of offsite power. They can be powered from EDG #1 (Unit 1) and EDG #2 (Unit 2) by manual action. (Section 7.2.3.2.7)

The motor-driven auxiliary feedwater pumps are part of the emergency diesel generator sequencing scheme. This feature functions on a loss of offsite power concurrent with or subsequent to a safety injection. The EDG load sequencing scheme will trip the motor-driven auxiliary pumps, if running, and delay the motor-driven auxiliary feedwater pump restart for 10 seconds on SI or 140 seconds on hi-hi CLS (Section 8.5).

The operating bypasses associated with the automatic initiation logic circuitry (including sensors used for automatic initiation) during start-up or operation of the reactor are as follows:

1. The steam generator low-low level initiation circuitry is always active and can be bypassed by placing a particular channel in the test position. This action is restricted by the Technical Specifications. Since these channels are always active, a bypass removal mechanism is not needed.
2. Safety injection initiation circuitry is provided with a bypass for start-up purposes and is separately alarmed in the control room. This bypass (block) is automatically unblocked and requires no operator action.
3. During start-up, the circuit breakers for the motors of at least one main feed pump are closed in the test position to allow the motor-driven auxiliary feedwater pumps to be placed in the automatic mode when required by Technical Specifications. The breakers are procedurally taken out of the test position when the second main feed pump is placed in operation.
4. The auxiliary feedwater pumps may be prevented from starting by placing the pump controls in the PULL-TO-LOCK position. The auxiliary feedwater control is procedurally returned to the AUTO position prior to exceeding RCS temperature and pressure limits of 350°F and 450 psig.
5. Reactor coolant system loop isolation valves provide a signal, when closed, that prevents automatic start of auxiliary feedwater pumps from a steam generator low-low water level signal in the affected loop. This signal is automatically reinstated upon reopening of the valves. In the event this block is initiated, a permissive status light is lit in the control room to alert the operator of the condition. This is, however, not considered an operating bypass, since the plant operation is restricted to three-loop operation and at no time would it be operated with a loop isolated.
6. The reactor coolant pump undervoltage channels that sense the voltage on the station service buses A, B, and C are not provided with bypass capability during start-up or operation.

   No bypass capability is provided for the station blackout signal, which senses the voltage on the station transfer buses.

The automatic safety-related initiation circuitry for the auxiliary feedwater pumps originates in the engineered safeguards and reactor protection systems, which are designed in accordance with IEEE 279-1971. Portions of the automatic initiation circuitry, from the reactor coolant buses, main feedwater breakers trip, the loss of reserve station power, and the AMSAC initiation circuitry are not required to completely comply with IEEE 279-1971 because these initiation circuits are needed only as a backup or non-safety-related safeguards feature. Manual capability to initiate auxiliary feedwater operation from the control room has also been retained.

Safety-related initiating signals and circuits are powered from emergency buses, with testability an integral feature of the design.

The auxiliary feedwater motor-driven pumps can be locked out by placing pump control in the “pull-to-lock” position. This action prevents automatic initiation of the pump and, therefore, the auxiliary feedwater motor-driven pump overload trip annunciator actuates when the pump control switch is in the “pull-to-lock” position. In addition, a white status light for each auxiliary feedwater pump control switch indicates that its associated breaker is racked into the “connect” position and the breaker has closing control power available.

Safety-grade auxiliary feedwater flow instrumentation is provided in the control room. The instrumentation is powered from the emergency buses and meets regulatory requirements for diversity. Auxiliary feedwater flow to each of the three steam generators is indicated in the control room. Steam generator level instruments back up the flow instruments to satisfy the single-failure criterion. Each steam generator has three narrow-range and one wide-range level instrument loops, which read out in the control room and are energized from vital instrument buses. The auxiliary feedwater flow indication is testable from the transmitter back to the indicator. The total accuracy of the auxiliary feed flow loop is ±4% or better of span for normal operating conditions.

In response to NUREG-0737, it has been confirmed that the ECST has sufficient capacity to provide 700 gpm of auxiliary feedwater flow from the turbine-driven auxiliary feedwater pump for at least 2 hours independent of any AC power source. Auxiliary feedwater pump lube oil cooling is also independent of AC power because the lube oil coolers are cooled by a flow path from the pump discharge back to the pump suction. Emergency dc lighting provides sufficient lighting to manually control the turbine-driven auxiliary feedwater pump and discharge valves. Sound-powered phone communication capability is available in the vicinity of the auxiliary feedwater pumps and discharge valves.

Two parallel, pneumatic valves enable automatic control of the steam supply to the turbine-driven auxiliary feedwater pump, independent of any AC power. Each pressure control valve (PCV) is controlled by a DC-powered solenoid valve. A nitrogen tank with a regulator and a check valve has been added to the instrument air supply line to provide control of the PCVs for a period of 2 hours. The tank and check valve are necessary because the normal instrument air supply would not be available upon loss of all ac power.

Cavitating venturis (flow restrictors) have been installed in the 3-inch auxiliary feedwater lines leading to each steam generator. They are designed to limit the runout flow to approximately 350 gpm for the loop which has been affected by a main steam line break (MSLB) or main feedwater line break (MFLB). Correspondingly, this will permit the minimum required flow to be delivered to the unaffected steam generators.

The venturi design is based on the loss of the turbine driven AFW pump and the availability of two electric driven AFW pumps. Under the design conditions, the minimum required total flow of 350 gpm to the intact loops is met for core residual heat removal requirements.

Procedures are provided to assist the operators in manually starting the auxiliary feedwater system and controlling feed flow to the steam generators under a variety of operating conditions. Since the Surry Power Station has the capability of cross-connecting the two units' auxiliary feedwater systems, procedural guidance is provided on how to utilize the other unit's auxiliary feedwater system, if necessary.

Operability requirements for the auxiliary feedwater system and associated instrumentation are prescribed by the Technical Specifications.

The feedwater piping at the Surry Power Station incorporates several design features to reduce the likelihood of secondary-system fluid flow instability, i.e., water hammer:

1. Loop seals at the feedwater inlets to the steam generators are provided to reduce the length of piping that could be filled with steam if the steam generator feedring were to drain into the steam generator.
2. Top discharge feedwater spargers (J-tubes) reduce the likelihood of feedring drainage. The flow conditions to which the J-tubes are subjected are not severe, and J-tube stiffness is very high. The design has been evaluated for the expected service conditions and the integrity of the attachment weld will be maintained for the expected plant lifetime.
3. A full penetration weld between the steam generator feedwater inlet nozzle and the feedring prevents leakage from the feedring when steam generator water level is below the feedring.
4. The steam generator feedrings are offset approximately 2.5 inches in elevation above the center line of the feed nozzle to further delay draining of the feedwater piping.

During normal operation, the water level in the steam generator is maintained above the feedring and therefore steam cannot enter the feedring to react with cold feedwater. However, in the event of a transient that results in uncovering the feedring, the design features of the feedring and feedwater piping as discussed above will maintain the feedring full of water while flow to the steam generator is interrupted. Therefore, these design features preclude draining of the feedring and reduce the possibility of water hammer in the feedwater system.

10.3.5.4 **Tests and Inspections**

The auxiliary steam generator feedwater pumps and drives are tested in accordance with the Technical Specifications by admitting steam to the turbine drive or energizing the motor drivers. During these tests, verification of flow from the emergency condensate storage tank to the steam generators from each of the auxiliary feedwater pumps verifies proper alignment of the required auxiliary feedwater flowpaths. Periodic testing is staggered to test the motor-driven and steam-driven auxiliary feedwater pumps at different times to reduce the potential for inadvertently leaving closed the discharge valves of all pumps after a test. While a periodic test is being performed, the affected AFW pump is declared inoperable and the applicable Technical Specification limiting condition for operation is placed in effect.

10.3.6 Condenser

Two single-pass, divided water-box condensers are provided. Each condenses steam from one of the two low-pressure turbine exhausts, and steam from the turbine steam bypass valves, as described in Section 10.3.1.

10.3.6.1 **Design Basis**

The design parameters for each condenser are listed in Table 10.3-3.

10.3.6.2 **Description**

The condensers are of conventional design, manufactured by Ecolaire-Rand Company, and have a neoprene-lined rubber belt-type expansion joint in the neck. They also have steam and condensate crossover ducts to equalize pressure, and impingement baffles to protect the tubes. The tubes are made of titanium, which provides relative immunity from tube-end erosion/corrosion and reduces circulating water inleakage. The waterboxes have a 3/16-inch neoprene lining to provide protection and reduce maintenance. The tubesheet material is aluminum-bronze-D, ASTM B171, Alloy 614. In the event that excessive galvanic corrosion is experienced at the tube/tubesheet interface, an epoxy coating can be added to help minimize any corrosive effect of the electrochemical potential between the tubes and tubesheets. The material is a nonaging, nonshrinking, non-hygroscopic, nontoxic, non-water solution that will withstand corrosion, galvanic action, and cavitation. Internal tube support plates are spaced 24 inches apart. One No. 5 feedwater heater and one No. 6 feedwater heater are located in each condenser neck.

The condenser hotwell is of the deaerating type capable of reducing the oxygen content to less than 0.005 cm^3/liter. The deaerating capability is necessary, as there is no deaerating feedwater heater in the feedwater cycle. Hotwell division plates segregate the condensate from each tube bundle, with sample connections provided for each region. Samples are pumped to the turbine building for analysis.

Two twin-element, two-stage, steam jet air ejector units, each complete with tubed inter-condenser and after-condenser, are provided for removing noncondensable gases from the condenser shells. For normal air removal, one element of each ejector unit is operated per condenser shell. The ejectors function by using auxiliary steam and discharge to the atmosphere. A radiation monitor is installed in the common discharge line from the two air ejectors as described in Section 10.3.8. For initial condenser shell-side air removal, a noncondensing priming ejector is provided for each shell. These ejectors function by using steam from the auxiliary steam system (Section 10.3.2).

10.3.6.3 **Performance Analysis**

Loss of normal ac power causes the four 96-inch condenser outlet valves to partially close. This closure permits the minimum flow of circulating water to continue through the condenser for the main steam bypass system, and conserves water in the intake canal for the recirculation spray coolers.

10.3.6.4 Tests and Inspections

Circulating water and those service water isolation valves, which are required to close to conserve intake canal inventory following a design basis accident, are periodically verified that the total leakage flow from these sources are limited to less than the leakage assumptions of the canal inventory analysis.

10.3.7 Lubricating Oil System

A pressure lubricating oil system is provided to perform the following functions:

1. Store lubricating oil.
2. Supply oil to and receive oil from the turbine-generator oil reservoir.
3. Purify a side stream of oil from the turbine-generator oil reservoir on a continuous-bypass basis.
4. Clean and reclaim used oil from the storage tanks, pumping it from the used-oil storage tank via the purifier to the clean-oil storage tank.

10.3.7.1 Design Basis

The lubricating oil system consists of a 21,000-gallon reservoir, two 22,000-gallon horizontal all-welded steel storage tanks, an oil purifier, and two identical motor-driven transfer pumps. The two gear-type positive displacement transfer pumps are each capable of two-sided operation at 108 and 48 gpm to accomplish the various batch cleaning, transfer, and circulating operations. The variable speed oil conditioner pump for each unit is rated up to 100 gpm.

10.3.7.2 Description

A turbine shaft-driven oil pump normally supplies all lubricating oil requirements to the turbine-generator unit. An ac motor-driven turning gear oil pump is installed for supplying lubricating oil during start-up, shutdown, and standby conditions. An emergency dc motor-driven oil pump, operated from the black battery, is also available to ensure lubricating oil to the bearings.

Cooling water from the bearing cooling water system (Section 10.3.9) is used for the turbine lube-oil coolers. The two 22,000-gallon storage tanks are normally designated “clean” and “used,” but are interchangeable and are located inside a fireproof room equipped with water sprays and vent fans. The transfer pumps and piping are arranged so that oil can be processed from the oil reservoir or either of the two storage tanks. The processed oil can be returned to either of the other two. A vapor extractor purges oil fumes from the reservoir and exhaust to the atmosphere outside of the turbine building. Piping and valves in the system are of welded steel, and high-pressure bearing oil piping is enclosed in a guard pipe.

10.3.7.3 **Performance Analysis**

The dc motor-driven oil pump is designed to function during a loss of station power to supply lubricating oil to the turbine-generator bearings. The black battery provides an uninterrupted source of power to this pump.

10.3.7.4 **Tests and Inspections**

The dc bearing oil pump is tested periodically.

10.3.8 Secondary Vent and Drain Systems

Because the steam and power conversion system is normally nonradioactive, vents and drains are arranged in much the same manner as those in a fossil-fueled power station. However, because air ejector vents and steam generator blowdown can possibly become contaminated and because they discharge to the environment, they are monitored and discharge under controlled conditions as described in Chapter 11.

The air ejector vent subsystem is shown in Reference Drawing 2. The steam generator blowdown system is shown in Reference Drawing 8.

10.3.8.1 **Design Basis**

Each of the condenser steam jet air ejectors (two per shell) is designed to remove 12.5 cfm of free air. Each ejector normally uses about 800 lb/hr of steam at a 140 to 200 psig from the auxiliary steam header, while using 900 gpm of condensate for cooling. Separate hogging or vacuum priming jets are used to reduce condenser vacuum to 1 to 3 inches Hg absolute during start-up.

10.3.8.2 **Description**

Generally, secondary plant piping drains to the condenser.

Vent gases removed from the condensers by the air ejectors are normally discharged through a radiation monitor (Section 11.3) to the atmosphere. If a steam generator tube ruptures, with subsequent contamination of the steam, the radioactive noncondensable gases would be detected by the radiation monitor located in the air ejector effluent line. The related accident analysis is covered in Section 14.3.1. When the radioactivity level reaches the alarm setpoint of the monitor, trip valves in the air ejector effluent line will automatically actuate to divert the effluent flow to the containment and shut off the vent to atmosphere. Other vents from the turbine generator that handle carbon dioxide, hydrogen, oil vapor, and other nonradioactive gases are discharged directly to the atmosphere outside the turbine building.

As discussed above, the condenser air ejector discharge line is a potentially radioactive release point and is therefore required to have high-range radiation monitoring per the requirements of NUREG-0578, Section 2.1.8.b. For this reason, two manual isolation valves have been installed and the air ejector discharge lines have been rerouted to have connections upstream of ventilation vent no. 2 high-range effluent monitor for use during accident conditions. If a condition were to exist such that a radiation monitor (low range) alarms and the containment is under a phase I isolation mode, the air ejector isolation valves would shut and secure all flow from the air ejector vent. However, this modification provides a method for maintaining condenser vacuum, if necessary, by allowing the operator to manually establish condenser-air ejector flow through the new discharge line and the high-range vent stack monitor, as well as the low-range effluent monitor. Both of the manual isolation valves are under administrative control. The high-range effluent monitor isolation valve is normally shut and the low-range effluent monitor manual isolation valve is open.

10.3.8.3 **Performance Analysis**

Loss of power or air causes both diversion valves in the air ejector line to fail closed, thus preventing possible radioactive contaminants in the condenser steam space from reaching the atmosphere. In addition, the air-operated shut-off valves in the steam supply lines to the air ejectors will also go closed on a loss of power or air.

Radiation monitoring and alarm initiation are unaffected by loss of power, but a signal from the containment isolation system (Section 5.2) causes the trip valves on the outside of the containment wall to close.

10.3.8.4 **Tests and Inspections**

The vent and drain systems are in continual use and require no special testing and inspection. However, the trip valves installed in these systems, which are part of the containment isolation system, are tested in accordance with Section 5.2.

10.3.9 Bearing Cooling Water System

The bearing cooling water system supplies cooling water to the steam and power conversion system equipment and is a closed cycle system using pumped condensate quality water as cooling water. The heat removed by the cooling water is transferred to service water in the bearing cooling heat exchangers, as described in Section 9.9. A review of the effects of the power uprate to a core power of 2589.3 MWt was conducted and the bearing cooling water system was found to be adequate.

The bearing cooling water system is shown schematically in Figure 10.3-11 and Reference Drawing 9.

10.3.9.1 **Design Basis**

The turbine plant equipment is designed for full load operation with cooling water supplied at a maximum temperature of 105°F. The bearing cooling water heat exchangers consist of three half-size units capable of maintaining the cooling water supply temperature below 105°F at all river water temperatures.

The principal equipment served by the bearing cooling water is listed in Table 10.3-4.

The full-size 13,000-gpm motor-driven pumps circulate the cooling water through the above equipment and the bearing cooling heat exchangers.

10.3.9.2 **Description**

The cooling water flowing through the major equipment coolers, such as the hydrogen and oil coolers, is controlled manually to maintain constant temperature of the cooled fluid.

A head tank is provided to maintain a positive pressure at all points on the system. Makeup to this tank is normally from the water supply and treatment system header; however, when this system is not in operation, makeup is provided from the condensate system (Section 10.3.5).

The bearing cooling water system is chemically treated to inhibit corrosion.

10.3.9.3 **Performance Analysis**

The bearing cooling water system supplies cooling water to steam and power conversion system equipment, for heat removal. The bearing cooling water system is non-safety-related and is not relied upon for accident mitigation or safe-shutdown of the nuclear plant.

10.3 REFERENCES

1. U.S. Nuclear Regulatory Commission, *Seismic Analyses for As-Built Safety-Related Piping Systems,* IE Bulletin 79-14, June 2, 1979.
2. Letter from A. Schwencer, NRC, to W. L. Proffitt, Vepco, Subject: Safety Evaluation of the Steam Generator Repair Program by the Office of Nuclear Reactor Regulation, License Nos. DPR-32 and DPR-37, dated December 15, 1978.
3. U.S. Nuclear Regulatory Commission, *TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendation*, NUREG-0578, July 1979.
4. Revised report on the Reanalysis of Safety-Related Piping Systems. Surry Power Station - Unit 1, August 1979, Stone & Webster Engineering Corporation.
5. Report on the Reanalysis of Safety-Related Piping Systems - Surry Power Station - Unit 2 Rev. 1, April 1980, Ebasco Services, Inc.
6. Report on the I.E. Bulletin 79-14, Analysis for As-Built Safety-Related Piping Systems - Surry Power Station - Unit 2, July 1981, Ebasco Services, Inc.
7. ALSTOM Power, Report No. HTGD672084, Revision A, *Recommendations for the Inspection of LP Retrofit Internals Nuclear Turbines,* Released Date November 11, 2004.

10.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-064A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 1
	11548-FM-064A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 2
2.	11448-FM-066A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 1
	11548-FM-066A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 2
3.	11448-FM-066B	Flow/Valve Operating Numbers Diagram: Auxiliary Steam System, Primary Plant, Unit 1
4.	11448-FM-071A	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 1
	11548-FM-071A	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 2
5.	11448-FM-067A	Flow/Valve Operating Numbers Diagram: Condensate System, Unit 1
	11548-FM-067A	Flow/Valve Operating Numbers Diagram: Condensate System, Unit 2
6.	11448-FM-068A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 1
	11548-FM-068A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 2
7.	11448-FM-123A	Flow/Valve Operating Numbers Diagram: Chemical Feed Systems, Unit 1
	11548-FM-123A	Flow/Valve Operating Numbers Diagram: Chemical Feed System, Unit 2
8.	11448-FM-124A	Flow/Valve Operating Numbers Diagram: Steam Generator Blowdown Recirculation and Transfer System, Unit 1
	11548-FM-124A	Flow/Valve Operating Numbers Diagram: Steam Generator Blowdown Recirculation and Transfer System, Unit 2

9.	11448-FM-23A	Flow Diagram: Bearing Cooling Water System, Unit 1
	11548-FM-23A	Flow Diagram: Bearing Cooling Water System, Unit 2
10.	11448-FM-59A	Heat Balance Diagram: 2555.7 MWt Load, Maximum Calculated Load, No Evaporation, Units 1 & 2
	11548-FM-59A	Heat Balance Diagram: 100% Core Power, Unit 2

Table 10.3-1
STEAM GENERATOR BLOWDOWN SYSTEMS - CODES AND STANDARDS

Component	Codes and Standards
Heat exchanger	ASME Code, Section VIII, Division 1
Piping and fittings	ANSI B31.1, Code for Pressure Piping, *Power Piping*, 1967
Valves	ANSI B16.5, Flanged Valves, 1973
Instrumentation and controls	ISA Standards and Practices for Instrumentation (1974)

Table 10.3-2
CONDENSATE POLISHER SYSTEM DESIGN AND OPERATING INFORMATION

Design pressure	690 psig
Normal pressure	505-590 psig
Design flow	14,515 gpm
Normal flow per demineralizer	2420 gpm
Design temperature	135°F
Normal temperature	75-125°F
Number of demineralizers	6 (+l standby)
Number of demineralizers used at 100% power	6
Number of regenerations per day	1
Water used per regeneration	Approximately 50,000 gal

Table 10.3-3
CONDENSER DESIGN PARAMETERS

Steam condensed	6,195,000 lb/hr
Circulating water	773,000 gpm
Surface	650,870 ft^2
Number of tubes	71,328
Tube material	22 BWG titanium
Tube o.d.	7/8 in.
Effective length	39 ft. 10 in.
Backpressure	3.29 in. Hg
Heat load, Btu/hr at 90°F	5.807×10^9
Tube water velocity	6.6 ft/sec

Table 10.3-4
EQUIPMENT SUPPLIED BY BEARING COOLING WATER SYSTEM

Equipment	Design Flow, gpm
Generator hydrogen coolers	6048
Hydrogen seal-oil coolers	360
Turbine oil coolers	3380
Exciter cooler	300
Isolated-phase bus duct air coolers	167[a]
Condensate, feed, and heater drain pumps	334
Sample coolers and chillers for S/G on line chemistry monitoring system	154 (each unit)
Central chillers	1600 (each)
Vacuum priming sealwater coolers	100 (each)

a. The isolated phase bus duct coolers provide no cooling function. The isolated phase bus duct coolers are retained to provide a minimum flow path during plant outages.

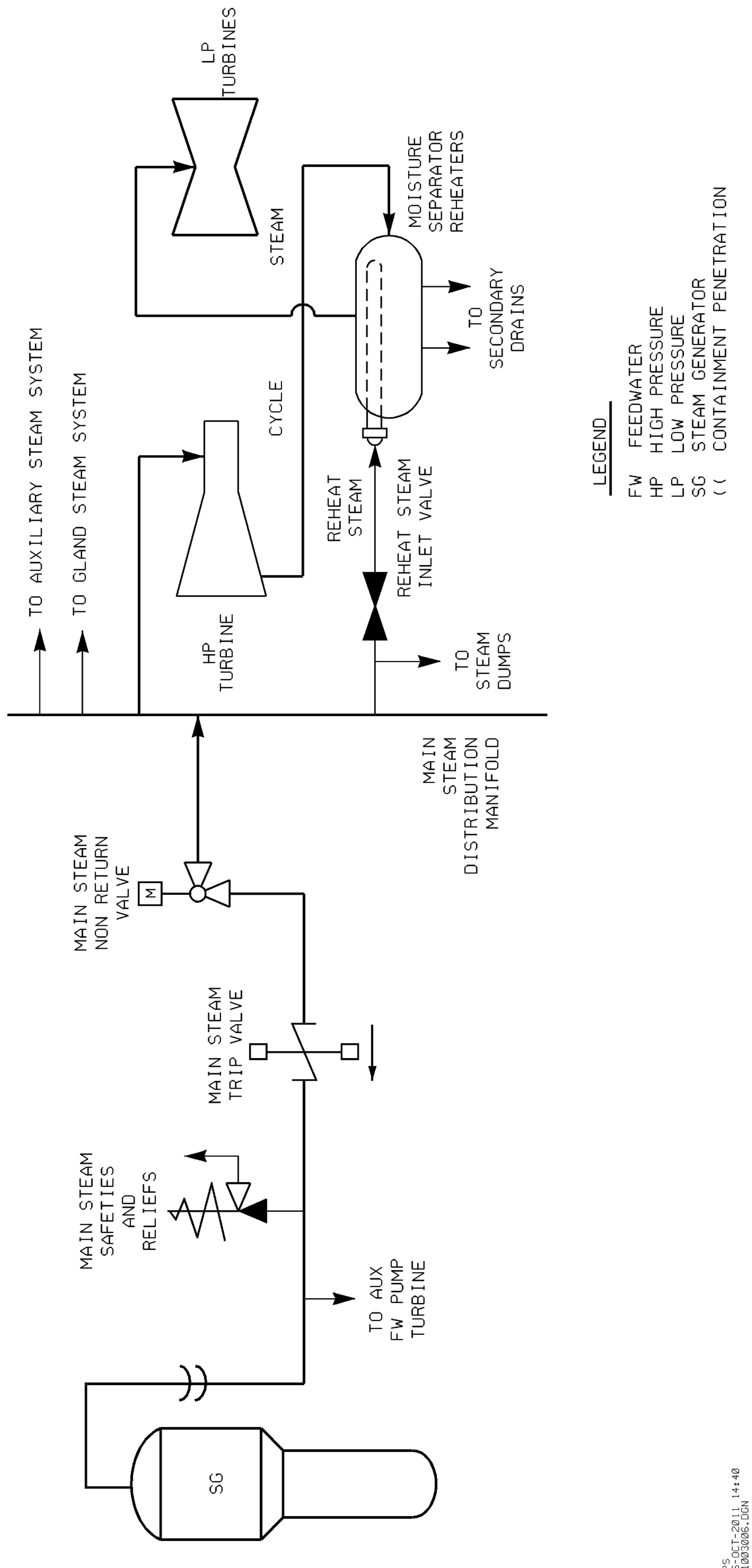
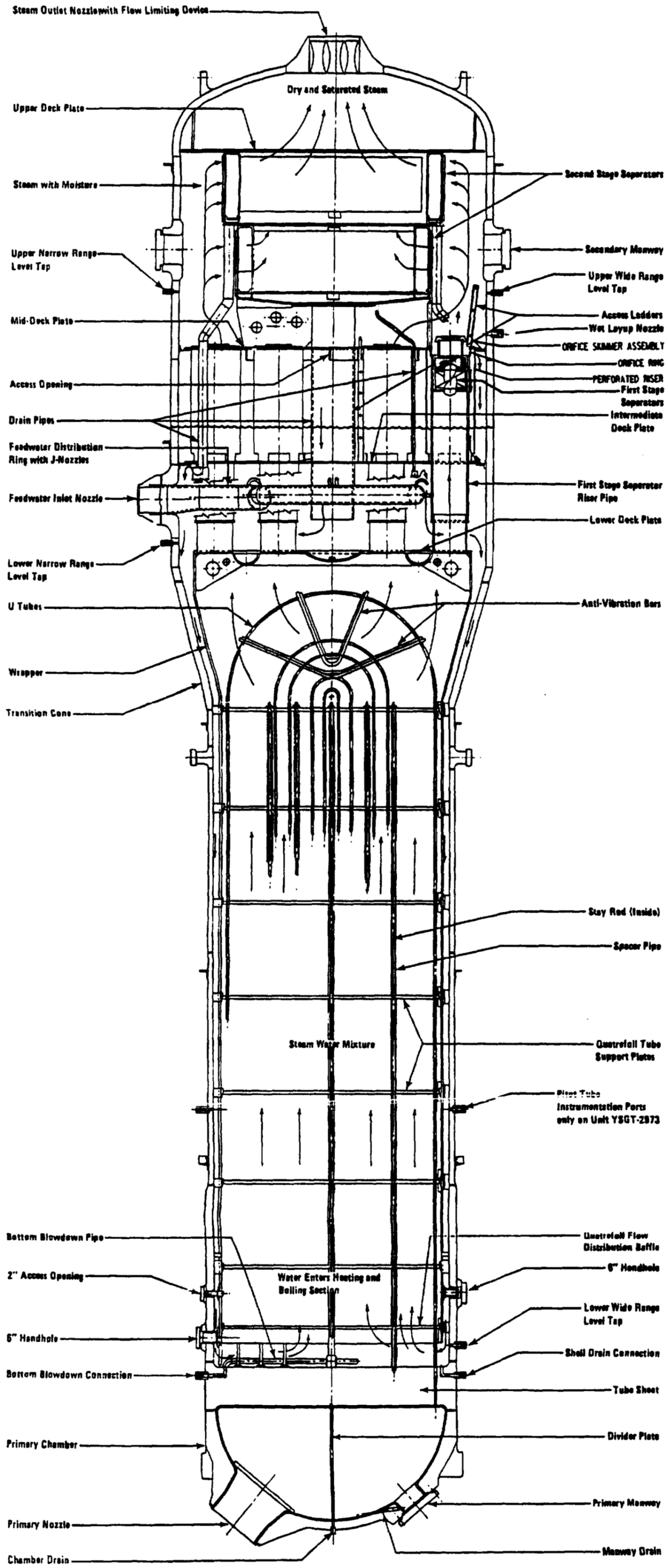


Figure 10.3-1
MAIN STEAM SYSTEM

Figure 10.3-2
SERIES 51 STEAM GENERATOR



S1003001

Figure 10.3-3
STEAM GENERATOR LOWER ASSEMBLY

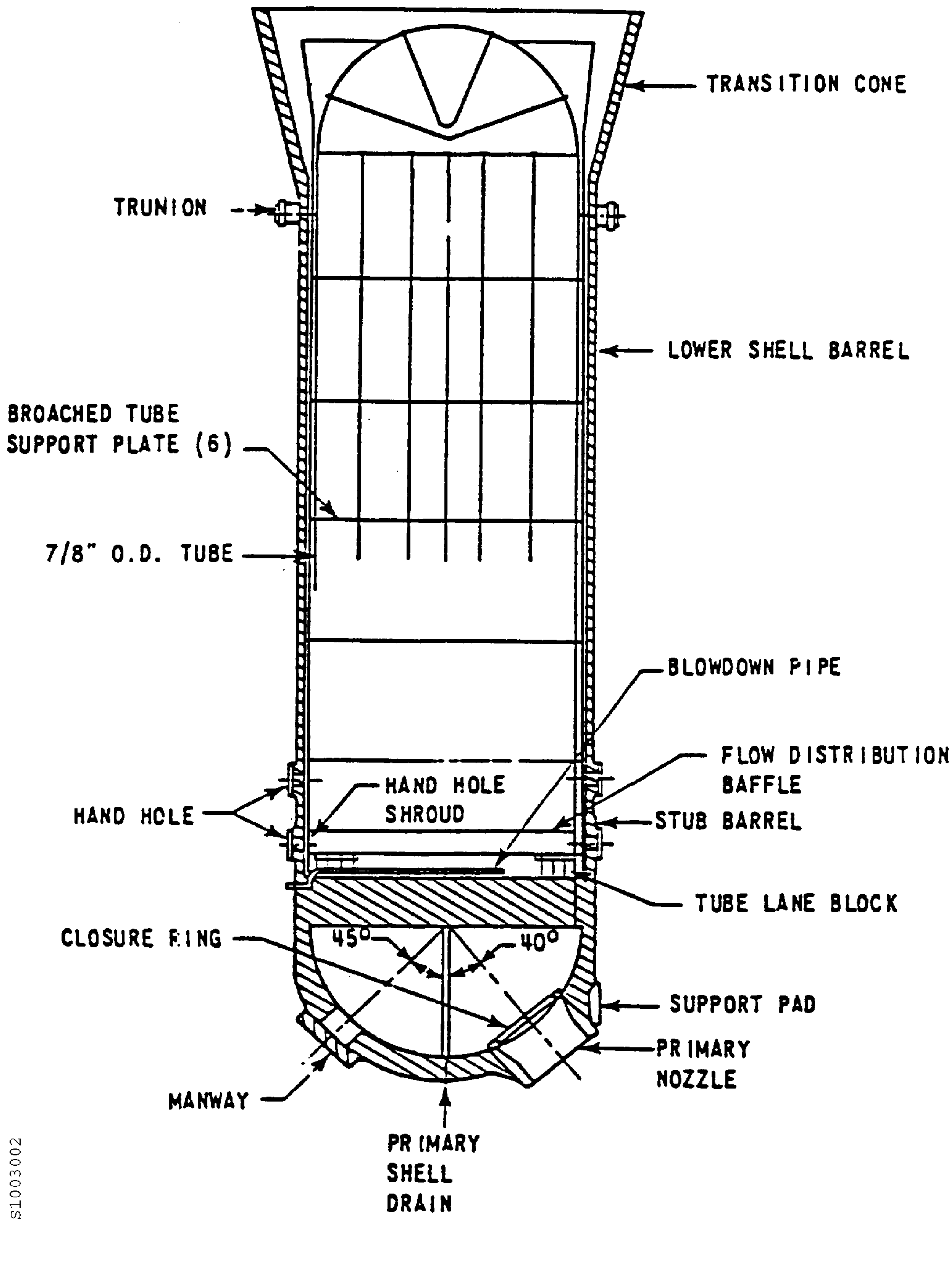


Figure 10.3-4
QUATREFOIL TUBE SUPPORT PLATE

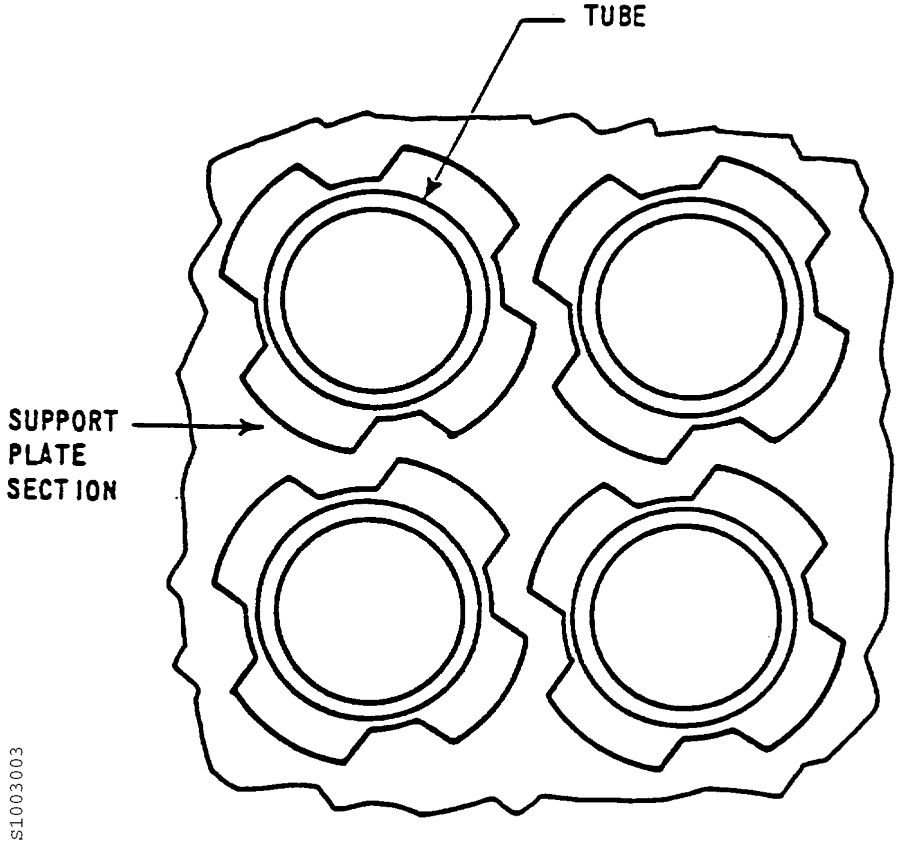


Figure 10.3-5
TYPICAL SLUDGE REMOVAL SYSTEM

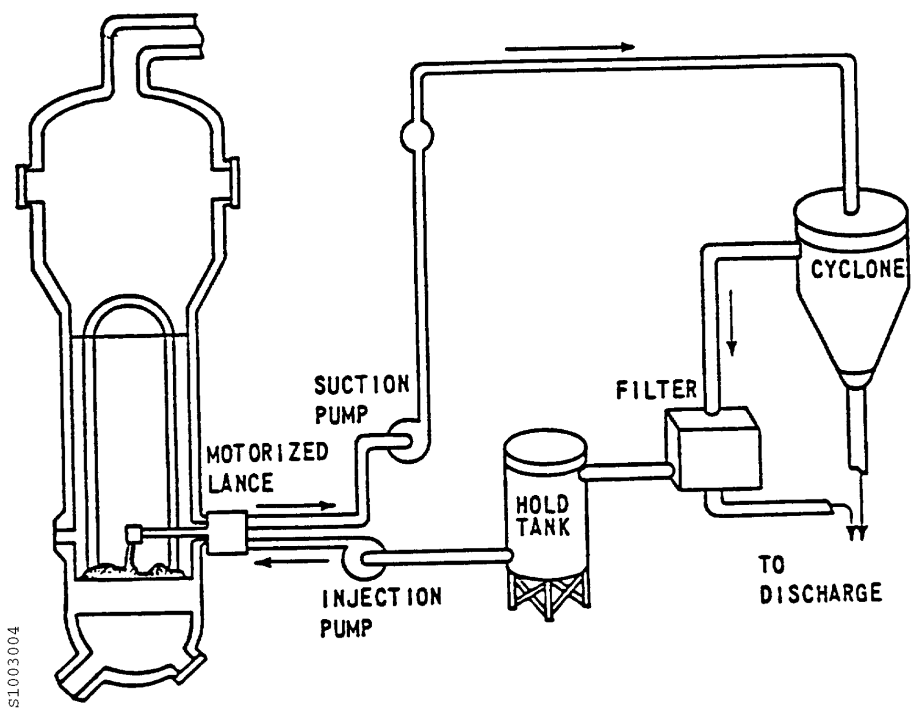


Figure 10.3-6
TYPICAL WET LAYUP SYSTEM

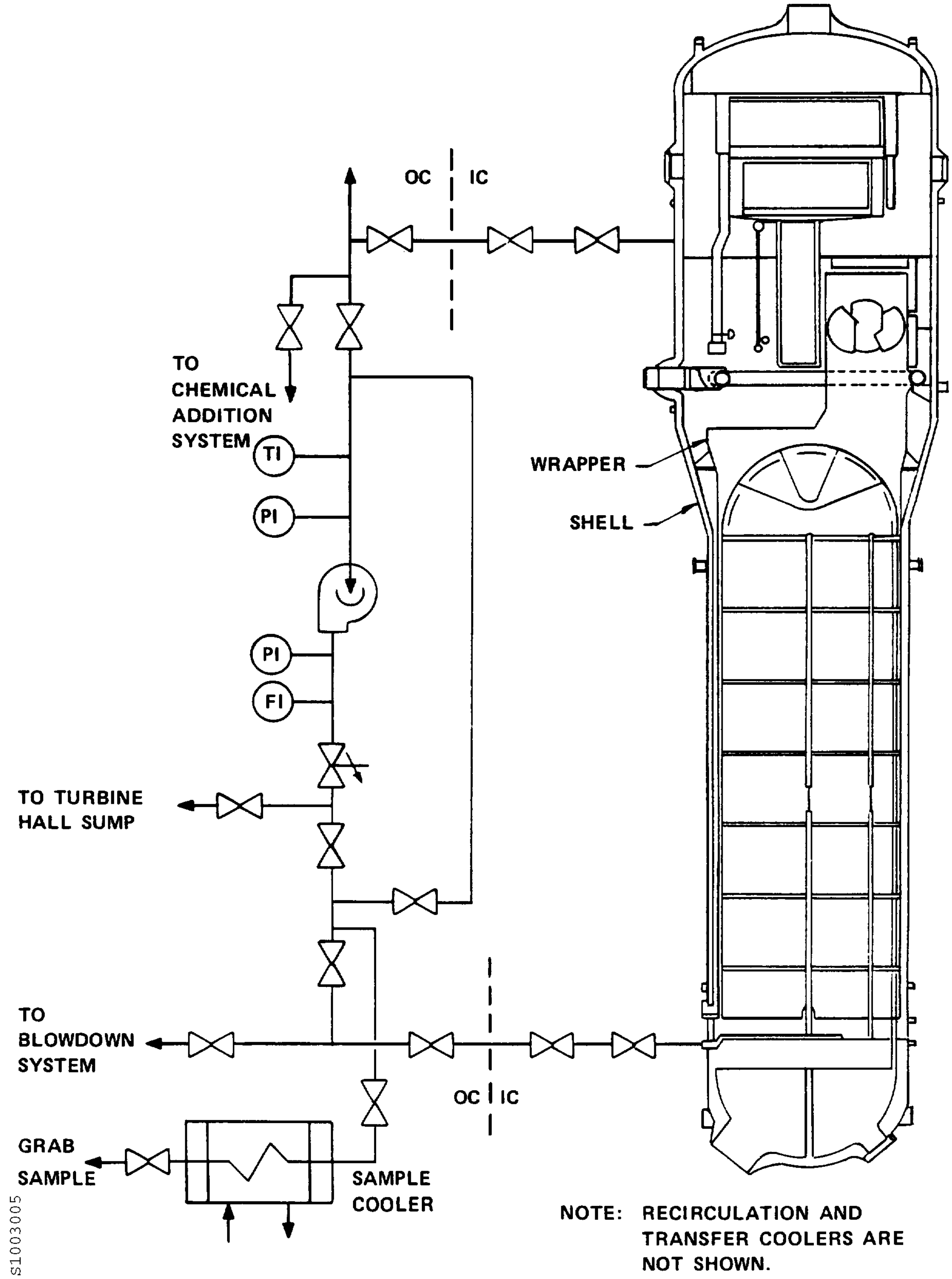
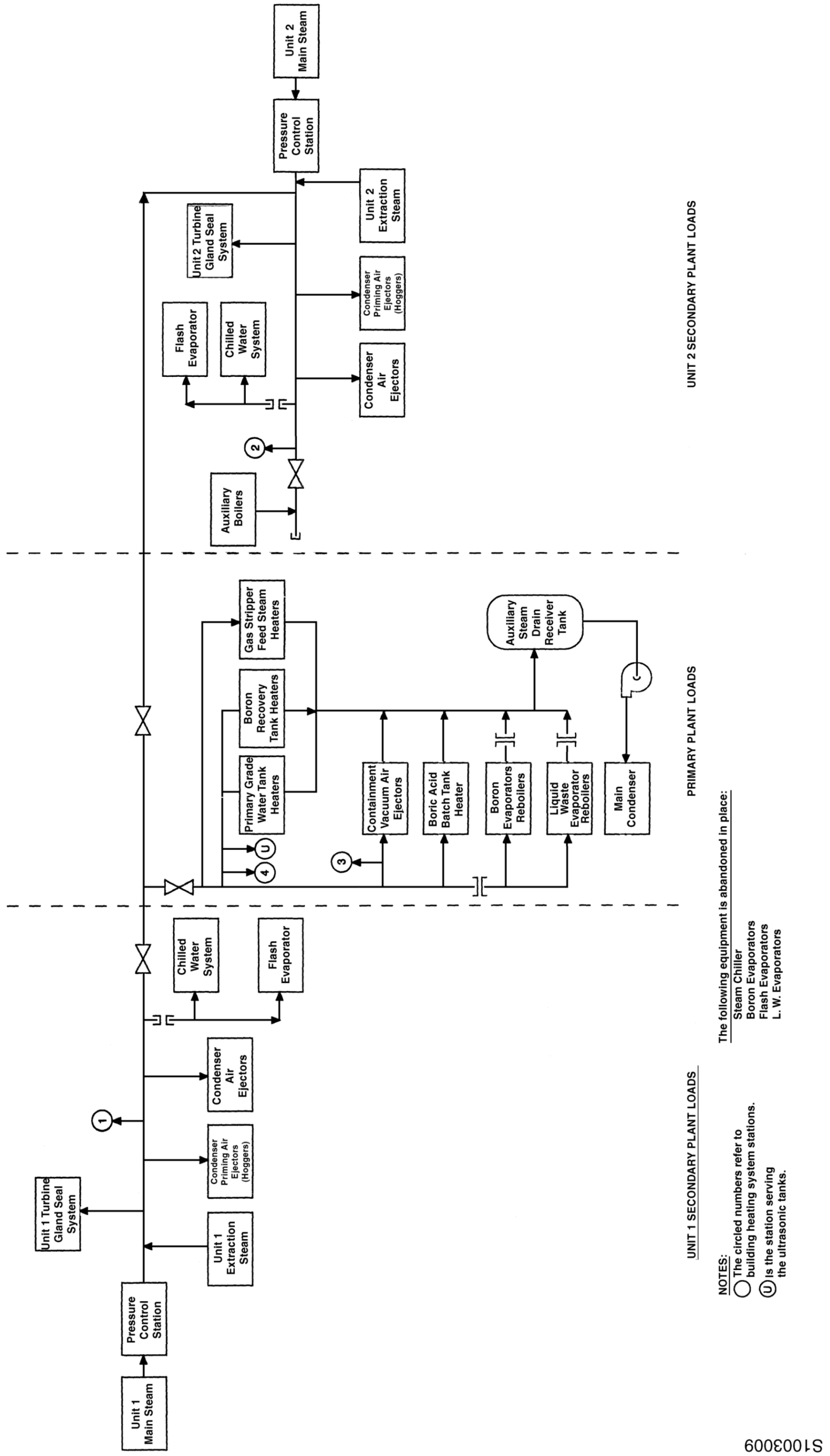


Figure 10.3-7
AUXILIARY STEAM SYSTEM



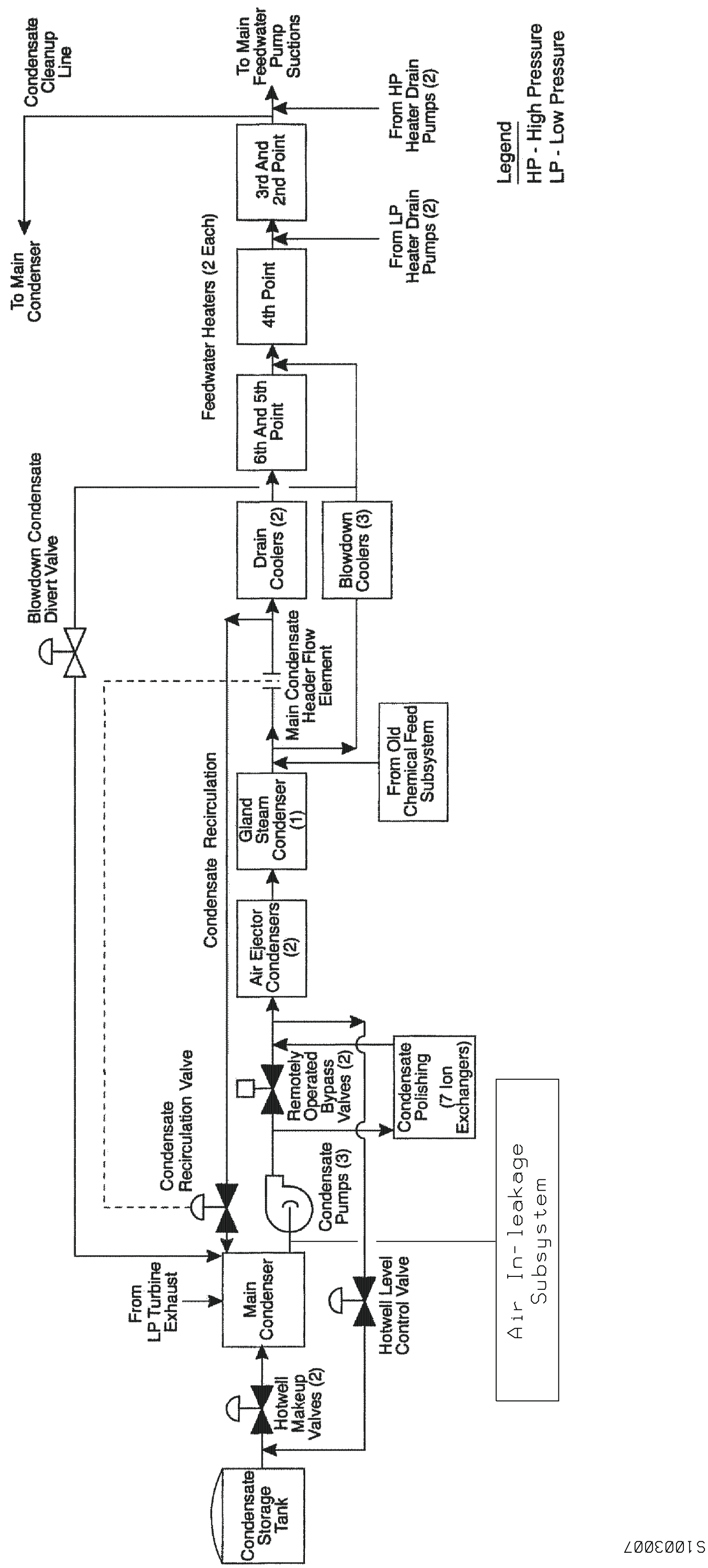
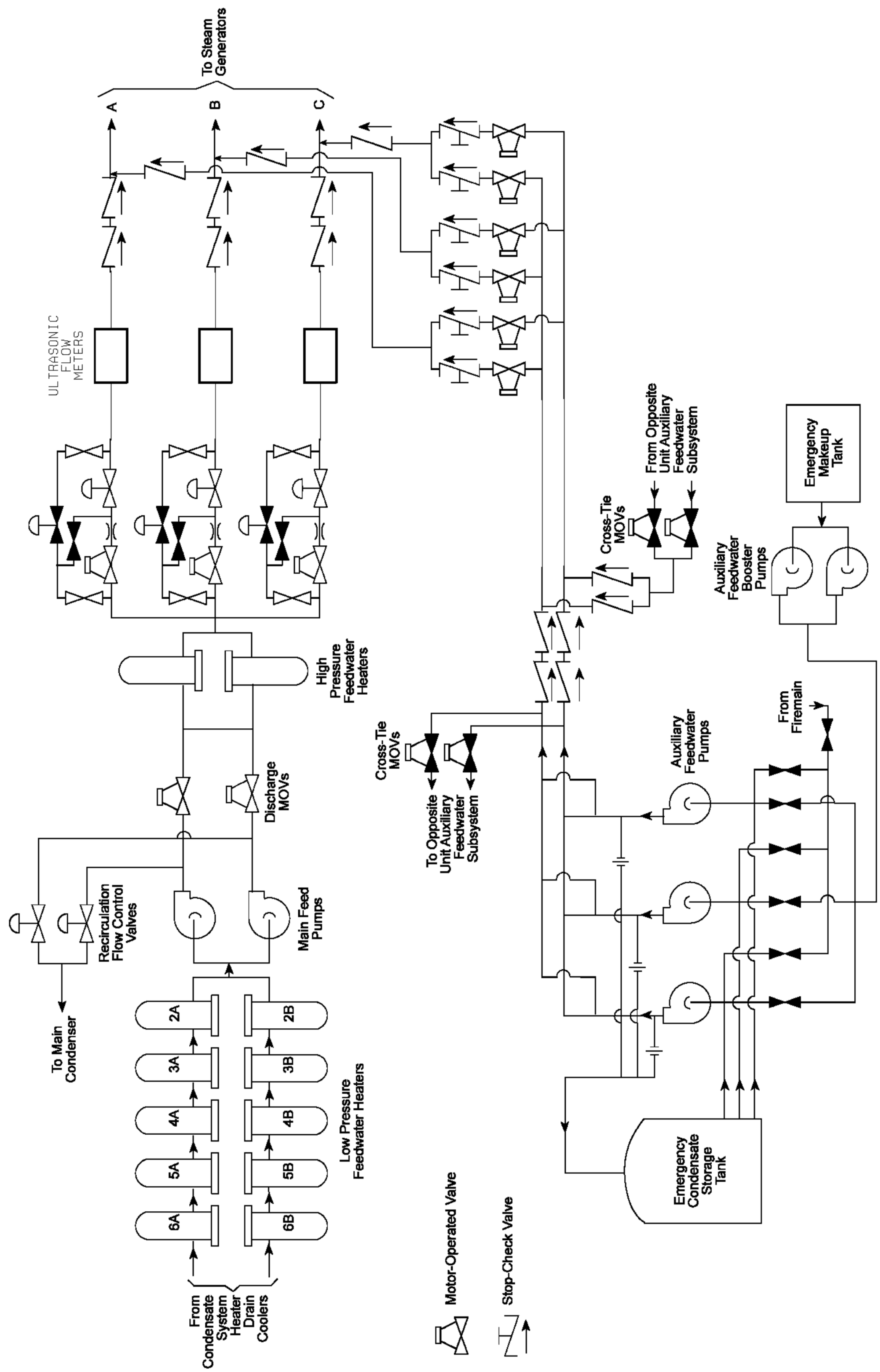


Figure 10.3-8
CONDENSATE SYSTEM

Figure 10.3-9
FEEDWATER SYSTEM



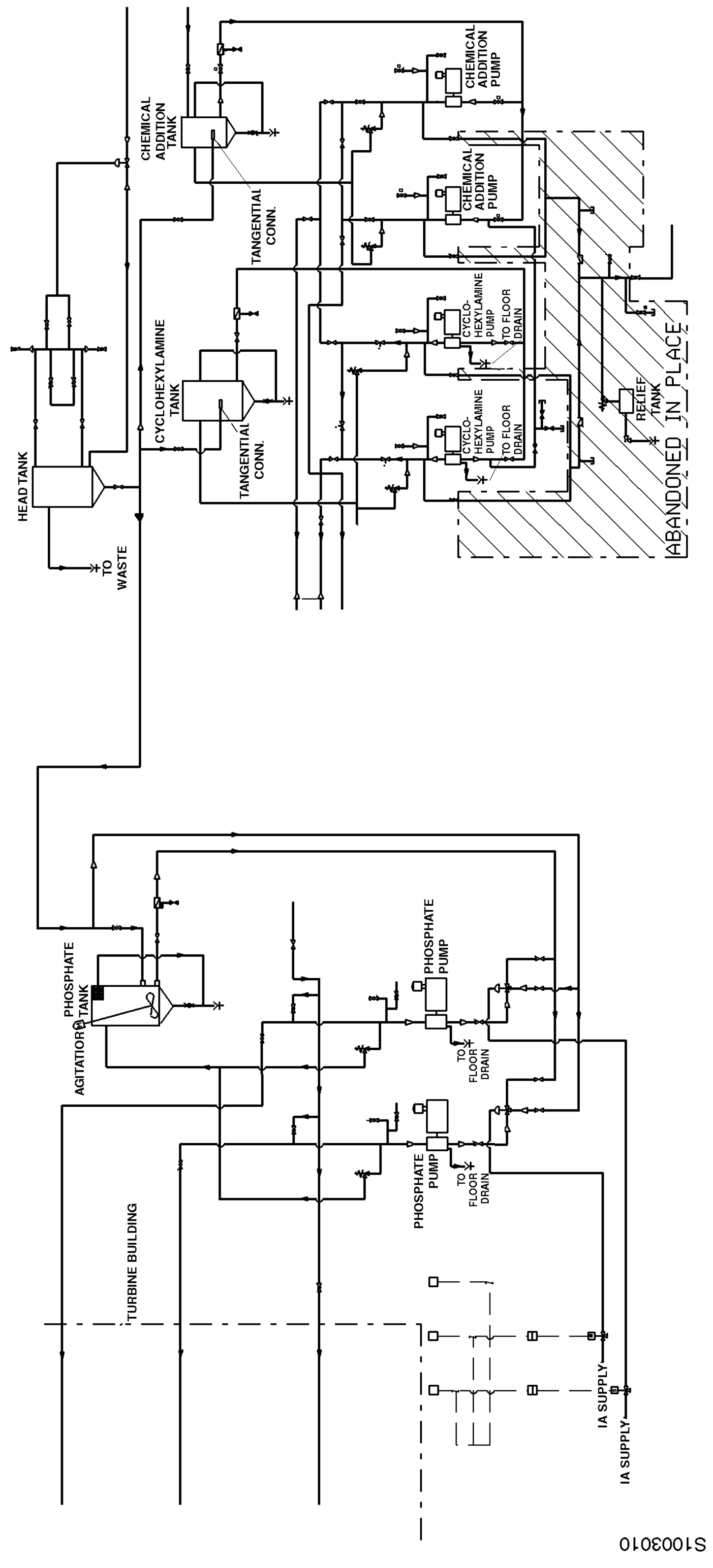
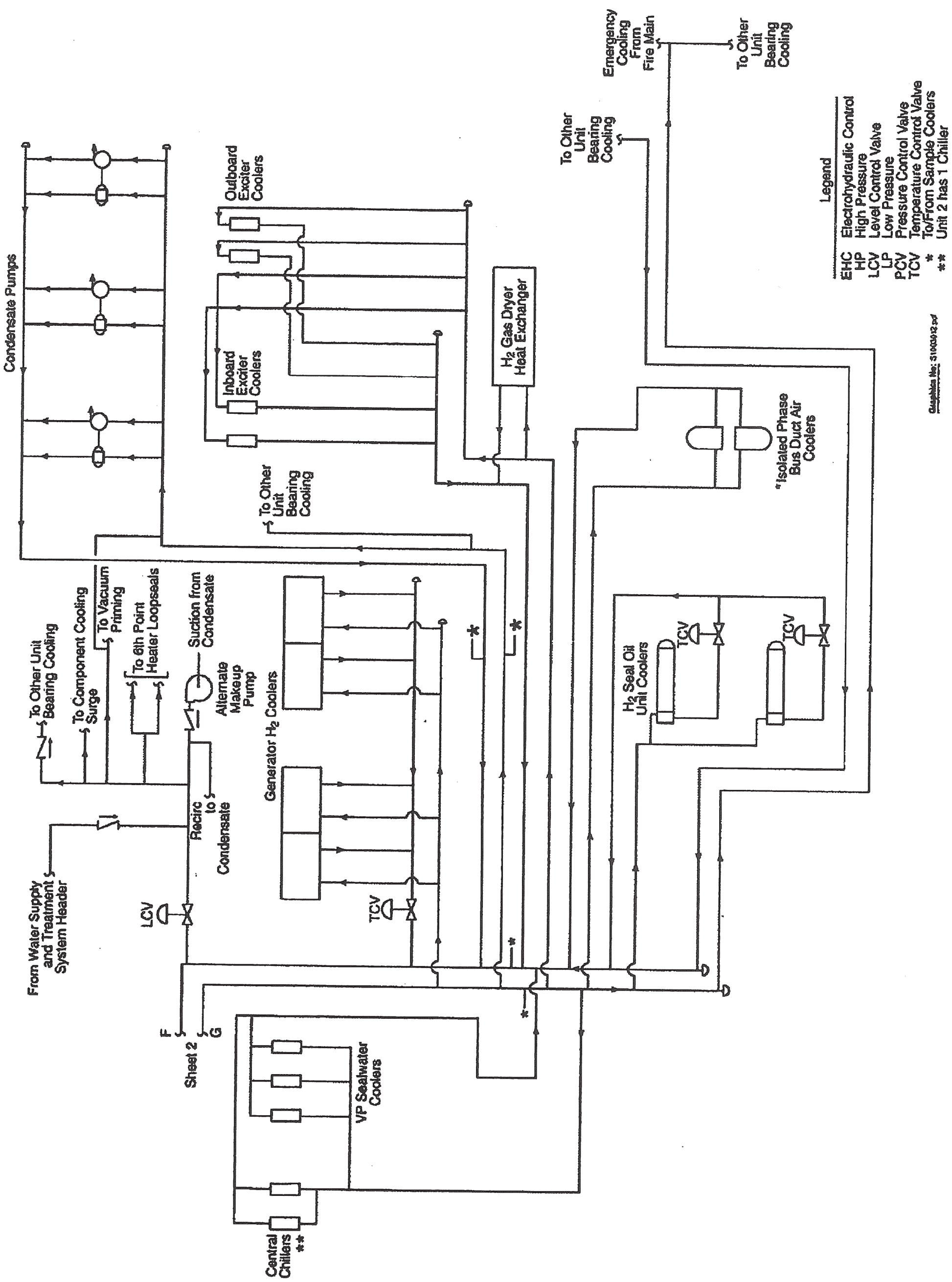


Figure 10.3-10
CHEMICAL FEED SYSTEM

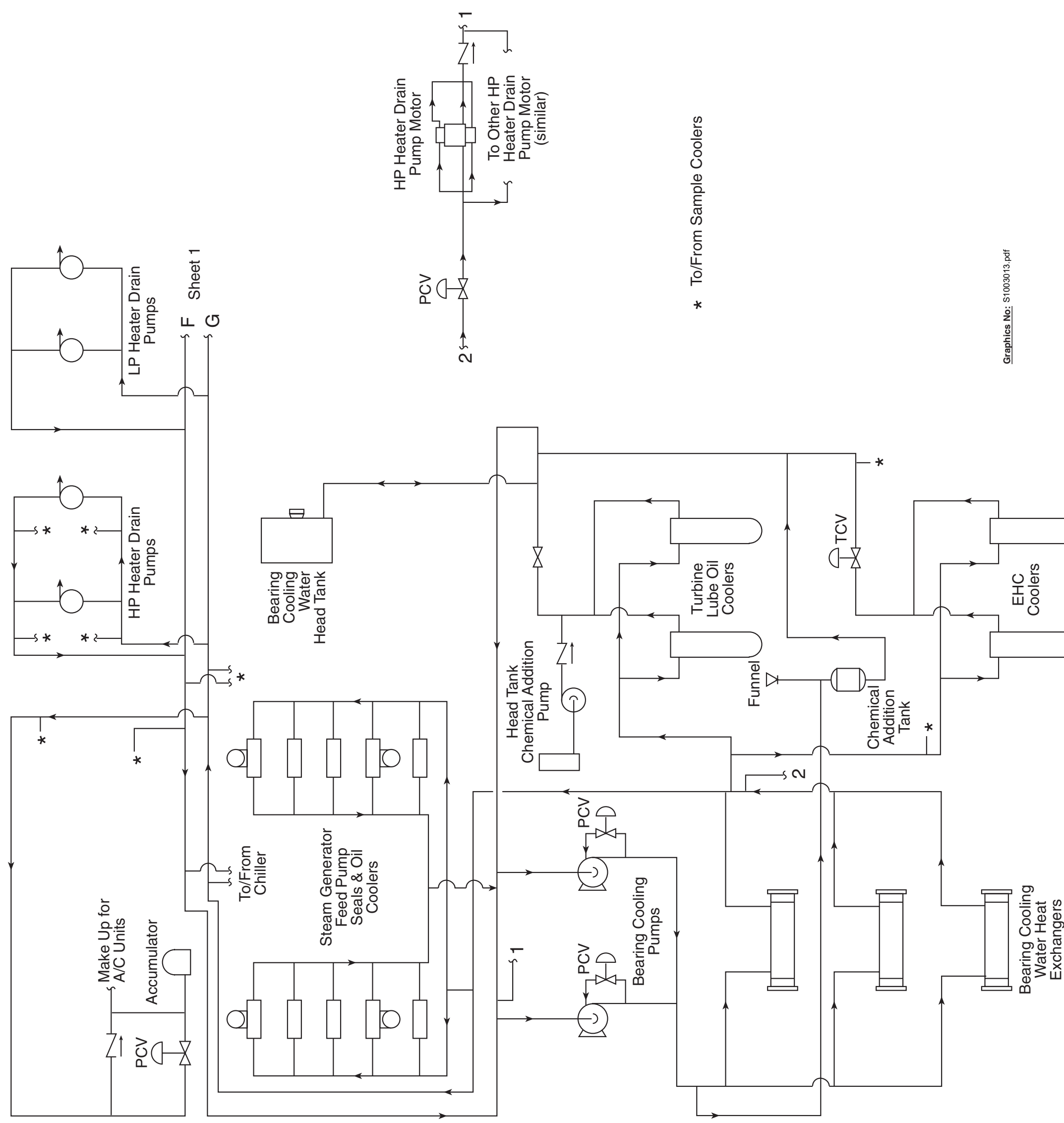
Figure 10.3-11 (SHEET 1 OF 2)
BEARING COOLING SYSTEM



*Note -The isolated phase bus duct coolers provide no cooling function. The isolated phase bus duct coolers are retained to provide a minimum flow path during Plant Outages.

S1ØØ3Ø12

Figure 10.3-11 (SHEET 2 OF 2)
BEARING COOLING SYSTEM



Surry Power Station
Updated Final Safety Analysis Report

Chapter 11

Intentionally Blank

Chapter 11: Radioactive Wastes and Radiation Protection
Table of Contents

Chapter 11: Radioactive Wastes and Radiation Protection
Table of Contents (continued)

Chapter 11: Radioactive Wastes and Radiation Protection
Table of Contents (continued)

Chapter 11: Radioactive Wastes and Radiation Protection

List of Tables

Chapter 11: Radioactive Wastes and Radiation Protection

List of Tables (continued)

Chapter 11: Radioactive Wastes and Radiation Protection

List of Figures

CHAPTER 11 RADIOACTIVE WASTES AND RADIATION PROTECTION

11.1 GENERAL DESCRIPTION

Note: As required by the Subsequent Renewed Operating Licenses for Surry Units 1 and 2, issued May 4, 2021, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

Waste disposal systems are provided to separate, treat, and dispose of radioactive liquid, gaseous, and solid waste materials. The liquid, solid, and gaseous waste disposal systems are common to both reactor units and designed to serve both units simultaneously. These systems incorporate one or more of the following basic processes:

1. Filtration, to remove particulate matter.
2. Evaporation, to concentrate and remove contaminants.
3. Demineralization, to remove dissolved material.
4. Compaction, to reduce the volume of compressible wastes.
5. Natural decay of radioactive isotopes.
6. Dilution, to reduce concentration.

Liquid, gaseous, and solid waste materials originate in the reactor coolant system, the auxiliary and emergency systems, the waste disposal system, and as a result of operation and maintenance procedures. Waste materials enter the waste disposal system directly from their source or via the vent and drain system (Section 9.7).

Adequate sampling, analysis, and monitoring of the waste disposal system are provided to comply with the design criteria. Process radiation monitors and flow-measuring equipment are provided for the surveillance of various station and radwaste effluents and process streams to ensure compliance with applicable regulations and to provide early indications of possible malfunctions and hazardous conditions.

Sufficient shielding is provided to reduce radiation to acceptable levels for normal operation and incident conditions. Allowable dose rates are based on applicable regulations, expected frequency, and the duration of exposure to radiation.

Area radiation monitoring equipment, health physics facilities, environmental programs, and administrative controls are provided for the surveillance and control of radiation exposure levels. These ensure radiation protection for plant personnel and the general public in accordance with applicable criteria.

Radiological and chemical respiratory protection equipment approved by the National Institute for Occupational Safety and Health/Mine Safety and Health Administration (NIOSH/MSHA) is provided. Equipment not tested and certified by NIOSH/MSHA requires specific authorization by the NRC and an approved exemption from 10 CFR 20.1703(a)(1), 10 CFR 20.1703(c), and certain parts of 10 CFR Part 20, Appendix A, Protection Factors for Respirators, Footnote d.2.(d) before use. Authorization has been received and appropriate exemption granted for the use of MSA Model Firehawk M7 SCBA, ultralite respirator, and 4500 psi tank charged with 35% oxygen and 65% nitrogen. All units are to be equipped with rubber face-pieces. Regulator use is not to be initiated at temperatures >135°F. Units may be used in areas where temperatures exceed 135°F if regulator use is initiated prior to entry into those areas. Breathing gas quality and composition, including hydrocarbon exclusion, are insured by strict controls and maintained in accordance with the latest revision of the United Stated Pharacopeia (USP) - The National Formulary (NF).

Prior to Unit 1 operation, a radiological study of the environs was performed (Section 11.3.5). It included an investigation of the background radiology relating to various forms of the aquatic and terrestrial environment. The nature and extent of the postoperational environmental survey were determined from the results of the preoperational study.

11.1 References

1. Letter from Karen Cotten, USNRC, to David A. Heacock, Virginia Electric & Power, May 28, 2010, *North Anna Power Station, Unit Nos. 1 and 2 And Surry Power Station, Units 1 and 2, Exemption From Certain Requirements of 10 CFR 20 (TAC Nos ME2835, ME2836, ME2828 and ME2829),* Serial No. 10-363.

11.2 RADIOACTIVE WASTE SYSTEMS

11.2.1 Design Bases

It is Vepco's waste management policy to maintain radioactive waste effluent from the Surry Power Station at the lowest practical level. In keeping with this policy, the Radioactive waste disposal system is designed, to the extent possible in accordance with maintenance practices, to maintain releases of radioactive material and radiation exposures to unrestricted areas as far below the limits of 10 CFR 20[1] as is practical. Normally, no radioactive waste stream will be discharged from the station without having first been processed through the waste disposal system.

The liquid, solid, and gaseous waste disposal systems are common to both reactor units. Each waste disposal system is designed to accommodate radioactive wastes produced during simultaneous operation of the two units. Both units are assumed to be operating on a daily load follow cycle using boric acid between 100% and 50% power.

The systems are also designed to accommodate the corrosion products originating in the reactor coolant system, and not removed in other systems.

11.2.2 System Design

The waste disposal system and radiation monitoring system are designed to satisfy the applicable sections of the general design criteria of Section 1.4. In addition, these systems are designed to limit the discharge of radioactive materials from the station so as not to exceed the limits of 10 CFR 20 or the suggested criteria of 10 CFR 100, and so as not to endanger the health of station operating personnel. The transportation of radioactive materials from the station is carried out in such a manner as to conform with applicable Federal, state, and local ordinances. Design data are given in Table 11.2-1. An evaluation of the waste disposal systems in accordance with the requirements of 10 CFR 50, Appendix I, is provided in Appendix 11A.

The liquid waste disposal system is described in detail in Section 11.2.3. This system has been designed to ensure that the release of radioactivity to the environment will be kept at the lowest practical level.

All normally radioactive waste gases from the gaseous waste disposal system, the gas stripper in the boron recovery system, the vent and drain system, various pressure relief valves, and the containment vacuum system are regulated before discharge by the process vent subsystem, as described in Section 11.2.5.1. All these sources of gaseous effluent are, before discharge collected; diluted; filtered through charcoal filters; monitored for flow rate, pressure, temperature, and particulates and gaseous activity; and then released through the process vents.

---

1. Virginia Power implemented the revised 10 CFR 20 on January 1, 1994. However, as allowed by the NRC, the calculational methodology used for the design analyses is based on the revision of 10 CFR 20 to which the plant was originally licensed.

Gas stripped from liquids entering the boron recovery system is stored in decay tanks as discussed in Section 11.2.5. The process vents and the process vent blowers are sized such that the minimum exit velocity is approximately 100 fps, which prevents any significant downdrafting of the effluent.

Radioactive waste gases may also be present in the Radwaste Facility (RF) ventilation system. Minor amounts of noble gases may be entrained in the liquid waste being processed by the RF. If evaporation of the liquid waste is the process method used, these gases will be released to the RF ventilation system. The RF ventilation system is designed to process and monitor these gases and any other airborne activity produced in the facility process areas. All tanks and process equipment vents which have radioactive contents are connected to the tank vent system. This system has a demister, a charcoal filter, and high-efficiency particulate air (HEPA) filter bank. The general area ventilation for the radiological controlled areas passes through a HEPA filter bank prior to discharge. Both the general area and the tank vent ventilation systems discharge through the RF vent stack and are continuously monitored. The exit velocity of the RF vent stack is in excess of 3200 fpm.

Other gaseous effluents will normally not be radioactive during operation; however, ventilation exhaust from some primary plant areas is subject to comparatively slight radioactive contamination from such limited sources as pump gland or pipe weepage. Features are incorporated in these exhaust systems to protect the environment from these relatively remote contamination possibilities. Three filter banks (two common and one stand alone) are capable of handling the largest possible exhaust ventilation flow rate that can be aligned through the individual filter bank(s). Each filter bank consists of roughing, HEPA, and charcoal filters. Exhaust bypass arrangements for selective filtration of any exhaust add to the flexibility of the system. All bypass and filter dampers are remote manually operated from the control room as required. Ventilation exhaust trains for the safeguards areas and charging pump cubicles automatically realign on a safety injection signal as discussed in Section 9.13.4.1.

The process vent, ventilation vents, and the RF vent are continuously monitored so that the effluent activity release rates result in concentrations considerably less than those limits provided by 10 CFR 20 at the site boundary. The gaseous waste disposal system is designed to provide adequate radioactive decay storage time for the waste gases prior to discharge through the process vent and, in addition, provides sufficient capacity to allow adequate holdup of these gases even when high-flow letdown is required.

The estimated releases from the gaseous waste disposal system are based on assumptions, discussed in Section 11.2.5, regarding the operation of the system. These assumptions were developed during the original plant design in order to generate estimates of gaseous effluent releases. These estimates were used to demonstrate compliance with effluent release regulations as part of the original licensing basis. Adherence to the gaseous waste effluent requirements is monitored by procedures in accordance with the Offsite Dose Calculation Manual (ODCM). Monitoring gaseous effluents in accordance with the ODCM ensures that the composite results of the variations in gaseous waste inputs and processing on the actual releases are within the accepted current licensing basis for the gaseous waste disposal system as specified in the acceptance criteria of the ODCM.

An analysis of the estimated curies of each radionuclide released from the station gaseous waste disposal system via the waste gas decay tanks has been made to demonstrate that 10 CFR 20 will be met. This analysis is presented in Section 11.2.5, and, as can be seen from Tables 11.2-2 and 11.2-3, the yearly dose at the site boundary with the recombiner operating is about 0.007 rem and is about 0.019 rem without the recombiner. These values are 1.4% and 3.8% (with and without the recombiner, respectively) of the unrestricted area dose of 0.5 rem specified in the revision of 10 CFR 20 to which the plant was originally licensed.

11.2.3 Liquid Waste Disposal System

The liquid waste disposal system for Units 1 and 2 is shared, except for the primary drain transfer tanks and the gaseous drain system in each containment. Two systems currently exist for treating liquid wastes. These are the boron recovery system and the liquid waste disposal system. The boron recovery system, which is described in detail in Section 9.2, treats effluents collected in the primary drain tank from the vents and drains system, as well as letdown from the primary coolant that is diverted from the chemical and volume control system (CVCS). The liquid waste disposal system treats the liquid wastes originating from containment, auxiliary building, fuel building, safeguards, radwaste facility and decontamination building sumps, and from laboratory drains. Steam generator blowdown may be transferred via the component cooling heat exchanger pit sump to the liquid waste disposal system as discussed in Section 11.2.3.2.2. Liquid waste originating from the containment, auxiliary building, fuel building, safeguards, component cooling water heat exchanger, and decontamination sumps and from the laboratory drains are collected in either the low-level waste drain tank or the high-level waste drain tank depending on the valve lineup in the primary vent and drain system. Liquid wastes are normally transferred to one of the two 30,000-gallon RF liquid waste collection tanks for processing through the RF evaporator system or are processed in the RF liquid waste reverse osmosis and demineralizer system. Liquid waste originating in the radwaste facility itself is collected in sumps and pumped directly to the RF liquid waste collection tanks or through filters to the laundry drain monitor tanks. An additional 60,000 gallons of transfer/storage capacity is available via the RF liquid waste surge tanks. The RF evaporator system is available for use during high liquid waste generation periods or as a backup to the RF liquid waste reverse osmosis and demineralizer system. Processed liquid waste is sent to the liquid waste monitor tanks. An inclined plate suspended solids/oil separator is in-line for either the evaporation or reverse osmosis and demineralization process options.

Laundry waste and personnel decontamination showers and sink wastes are collected in the contaminated waste drain tanks. These tanks are pumped to the RF for processing. Some large particulate liquid wastes originating in the radwaste facility are collected in the sumps and pumped to the laundry waste system for processing. Waste is processed with a laundry pre-filter and the laundry waste filter, then collected in the laundry drains monitor tank. Processed laundry waste and RF waste can be sampled and released or mixed with other station liquid waste.

Liquid and laundry wastes discharged to the circulating water system via the RF are monitored. The liquid effluent radiation monitor is an on-line monitor with automatic isolation of the effluent discharge when a high radiation alarm is received.

The Steam Generator Storage Facility sump is periodically pumped out and processed via the Laundry Drain System if contaminated.

Table 11.2-4 presents information regarding the originally licensed Surry liquid waste treatment system. This information provides parameters used as input into the calculation of radiation exposure to the public presented in Appendix 11A. With respect to the present Radwaste Facility, the information in Table 11.2-4 is conservative when compared to the RF radwaste volumes, DFs, and hold-up capacity. Therefore, the original evaluation of radiation exposure to the public presented in Appendix 11A bounds the design of the RF. Reference Drawings 1 through 3 and Figures 11.2-1, 11.2-2, 11.2-3, and 11.2-4 depict the liquid and laundry waste systems in the RF and their tie-ins to the station collection points.

11.2.3.1 **Components**

11.2.3.1.1 High-Level Waste Drain Tanks

Two high-level waste drain tanks are provided. Each tank has a usable capacity of approximately 2000 gallons. Level indicators are provided. These are stainless steel tanks designed according to Section III.C of the ASME Boiler and Pressure Vessel Code.

11.2.3.1.2 Low-Level Waste Drain Tanks

Two low-level waste drain tanks are provided. Each tank has a usable capacity of approximately 1785 gallons. Level indicators are provided. These are stainless steel tanks designed according to Section III.C of the ASME Code.

11.2.3.1.3 Contaminated Drain Tanks

Two contaminated drain tanks are provided. Each tank has a usable capacity of approximately 1045 gallons. Level indications are provided. These are stainless steel tanks designed to Section VIII of the ASME Boiler and Pressure Vessel Code.

11.2.3.1.4 Waste Disposal Evaporator and Auxiliaries (Installed But No Longer Used)

One forced-circulation evaporator with a feed capacity of 6 gpm is provided. The evaporator shell is fabricated from a high-nickel alloy in accordance with Section III.C of the ASME Code. Internals are fabricated from an austenitic stainless steel not susceptible to stress cracking.

The external heat source is a shell and tube steam reboiler fabricated on the tube side from a high-nickel alloy and on the shell side from carbon steel. Distillate is condensed in a water-cooled shell and tube condenser fabricated from austenitic stainless steel. The reboiler, shell, and tube condenser are all fabricated in accordance with Section III.C of the ASME Code, and TEMA Standards. (The external heat source steam lines have been cut and capped to preclude steam and/or water leakage.)

The condensed distillate is held in the distillate accumulator. This tank is fabricated from austenitic stainless steel in accordance with Section III.C of the ASME Code.

A distillate cooler is provided to further cool the distillate. The tube side of the distillate cooler is fabricated from austenitic stainless steel and the shell side from carbon steel, in accordance with Section III.C of the ASME Code.

11.2.3.1.5 Waste Disposal Evaporator Test Tanks (Installed but no longer used)

Two waste disposal evaporator test tanks, each of 3000-gallon capacity, with level indicators, are provided. These tanks are stainless steel and designed according to Section VIII of the ASME Code.

11.2.3.1.6 Pumps

Centrifugal frame-mounted pumps with single or double mechanical seals are provided. The waste disposal evaporator bottoms pump is a canned pump. One pump is provided for each tank with cross ties where appropriate, such as on high-level waste drain tank pumps. External cooling and seal water is supplied to radioactive pump seals as required.

11.2.3.1.7 RF Liquid Waste Evaporator System

The evaporator system consists of a 30-gpm forced circulation evaporator system. The evaporator is designed to concentrate waste up to a boron concentration of 24,500 ±5% ppm or the total solids concentration of 25 weight percent.

Normal feed to the evaporator is from a liquid waste transfer pump after the SPI oil/SS remover. Clean liquid effluent from the evaporator is transferred to the evaporator distillate demineralizer for further processing prior to transfer to the liquid waste monitoring tanks. The evaporator concentrates are forwarded to the bitumen solidification system for volume reduction, solidification, and packaging, or stored for later shipment in liquid form.

The evaporator is a forced circulation system utilizing a mechanical vapor recompression (MVR) system. The MVR evaporator operates on a heat pump principle. The process vapors are compressed to a higher pressure so they will condense at a higher temperature. The hot compressed vapors condense in the heater. The liberated heat causes boiling in the evaporator vapor body. Desuperheating water is added to the vapors to recover the superheat as sensible heat.

The liquor entering the vapor body flash boils to release heat in the form of water vapor. As the water is driven from the system in to vapor phase, the liquor contained in the vapor body is further concentrated. When the boron concentration reaches 24,500 ±5% ppm or the total solid concentration of 25 weight percent, a portion is removed by gravity to the Evaporator Bottoms Tank. The amount of concentrates removed is replaced by an increase in the feed rate, thus the solids concentration in the evaporator is decreased again.

The vapor leaving the vapor body passes through an entrainment separator. In the separator, the vapor flows upward through percolated trays and mesh pads. These remove droplets entrained in the vapor to protect the compressor wheel from erosion and to insure clean condensate.

The vapor from the separator is compressed by a high speed centrifugal compressor. The compressed vapors exit the compressor with a large amount of superheat, which is desuperheated to bring the vapor temperature close to saturation temperature and recover the superheat as sensible heat.

The vapor from the compressor is condensed on the shell side of the heater. The distillate flows by gravity to the distillate flash tank, where it is first flashed to the entrainment separator to recover heat. Then it is pumped through a distillate subcooler to the distillate demineralizer.

Concentrated waste from the evaporator is periodically discharged to the evaporator bottoms tank. The bottoms tank vent is connected to the tank vent system after passing through a vent cooler.

The major components of this subsystem are the vapor body, the heater, the recirculation pump, the entrainment separator, the vent gas cooler, a motor driven vapor compressor, a bottoms tank and bottoms tank pump. Design information on these components are given in Table 11.2-1.

11.2.3.1.8 RF Liquid Waste Reverse Osmosis and Demineralizer System

The RF liquid waste reverse osmosis (RO) and demineralizer system is designed to remove radioactivity and dissolved solids from the liquid waste process prior to collection in the liquid waste monitor tanks where liquids are sampled and discharged or reused. The RF liquid waste reverse osmosis and demineralizer system is normally in service to process liquid waste streams.

The RF liquid waste reverse osmosis and demineralizer system is designed to remove total suspended solids to < 25 ppm, and oil and grease to < 15 ppm prior to entering the liquid waste monitor tanks.

The system consists of demineralizer vessels and a Thermex RO unit. The RO concentrates are recirculated while the permeate is directed to the liquid waste monitoring tanks. The content of the process feed tank is directed to a collection tank when concentrate limits have been met.

The demineralizer vessels are designed and constructed per ASME VIII. The reverse osmosis skid was designed per ANSI B31.1.

11.2.3.1.9 Postaccident Radiation Waste Connection

The capability for processing highly radioactive postaccident liquid waste has been incorporated into the liquid waste disposal system. A flanged connection (Reference Drawing 1) is located in the vicinity of the boron recovery tanks for the purpose of discharging radioactive liquids to an external process system without requiring personnel to enter high radiation areas. The external process system would be brought onsite, if needed, following an accident. The postaccident radiation waste connection also has an isolation valve that can be operated by reach rod to further minimize personnel exposure.

11.2.3.1.10 RF Laundry Waste System

The RF laundry waste system receives waste from the contaminated drain tanks and from the RF building drain system sump pumps via a cross-connect line. The RF laundry systems consist of laundry drain prefilters and the main laundry drain filter.

The two laundry drain prefilters are installed in parallel with one operational to remove large solid matter such as cotton fibers to extend the service cycle of the downstream laundry drain filter. The filters are designed to operate at 50 gpm. The filtration media element is a bag type constructed of artificial fiber cloth. The filter media will be periodically removed manually and transferred to the dry activated waste (DAW) area for drying and volume reduction at the Radwaste Facility or packaged for offsite processing. The filter housing is constructed of 304 stainless steel.

The laundry drain filter is designed to remove particulate matter from the incoming laundry drain stream. The filter is designed to operate at a rate of 50 gpm. It is designed to remove suspended solids with a filtration media of polyethylene fiber balls. The expended filter media will be removed manually and transferred to the DAW compaction area for drying and volume reduction at the Radwaste Facility or packaged for offsite processing.

The filter vessel is designed and constructed in accordance with ASME VIII. The principal material of construction is 304 stainless steel.

Laundry waste and RF building drain system waste processed by this system is sent to the laundry waste monitor tanks for sampling prior to monitored discharge.

11.2.3.1.11 RF Monitor Tanks

The RF liquid waste evaporator, reverse osmosis, and/or demineralization process systems send their processed waste to one of two liquid waste monitor tanks. These tanks are 15,000 gallons, vertical tanks. Each tank has level indication and recirculation capability. They are constructed of 304 stainless steel and have an atmospheric pressure design. The tanks are designed and constructed to ASME Section III.

Laundry waste processed through the RF is sent to one of two laundry waste monitor tanks. These tanks are 7500 gallons, vertical tanks. Each tank has level indication and recirculation capability. They are constructed of 304 stainless steel and have an atmospheric design. The tanks are designed and constructed to ASME Section III.

11.2.3.2 Processing Steam Generator Blowdown

The steam generator blowdown system is described in Section 10.3.1.2. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the steam generator blowdown system was found to be adequate.

A steam generator blowdown treatment system, located in the Condensate Polisher Building, was utilized to remove impurities from the blowdown stream. The system contained prefilters, demineralizers, and postfilters. The blowdown treatment system was designed to be used during normal operation and following steam generator tube leakage. Subsequently, the system was determined to be incompatible with changes made in secondary water chemistry. As a result, the blowdown treatment system is no longer used for blowdown treatment and blowdown is untreated, except as described below.

11.2.3.2.1 Normal Operation

During startup and power operations, blowdown is either released to the discharge canal or returned to the condenser hotwell as described in Section 10.3.1.2. During outages, the steam generators may be gravity drained through the blowdown lines to a waste neutralization sump located in the condensate polishing building. Water in the waste neutralization sump can be treated, recirculated, sampled and discharged to either the settling pond or the circulating water discharge. During discharge, the water may be directed through a filter or the filter can be bypassed.

11.2.3.2.2 Operation Following Steam Generator Tube Leak

If a steam generator tube leak occurs and shutdown is desired, station procedures provide guidance on evaluating contamination potential and determining appropriate actions for processing blowdown. Depending on activity levels, blowdown may be directed to the condenser hotwell or may need to be processed through the Surry Radwase Facility (SRF). If it is decided to process the blowdown through the SRF, procedures direct that the inventory from the affected steam generator be transferred to the component cooling (CC) heat exchanger (HX) pit sump using blowdown hose connections. Steam generator pressure will provide the motive force for transfer from the affected steam generator to the sump, but gravity transfer is possible. The CC HX pit sump pump transfers water in the sump to the combined containment and safeguard area sump pump discharge header where it can be processed by the liquid waste disposal system (Section 11.2.3). The flow rate into the sump from the affected steam generator will be limited to less than 25 gpm so that it will not exceed the pumping capacity of the CC HX pit sump pump. The flow rate can be controlled from the main control room by use of an HCV in the blowdown line.

Controls are in place to minimize the airborne activity levels in the vicinity of the CC HX pit. Hose connections will be monitored for leakage. Water entering the sump from the blowdown lines will be cooled by the steam generator blowdown coolers to a subcooled condition to preclude flashing. Flow rates into the CC HX pit sump will be limited to below the capacity of the CC HX pit sump pump so that the water level remains in the sump and does not enter the pit. This minimizes the liquid surface area and would allow for an exhaust hood to be installed over the sump if needed to reduce airborne activity levels. Health Physics will monitor the radiation levels in the areas of the routed hose and the radiation and airborne levels around the CC HX pit.

11.2.4 Solid Waste Disposal System

The solid waste disposal system provides logging, packaging, and storage facilities for scheduled shipment off the site and ultimate disposal of radioactive waste material. Materials handled as solid waste include concentrated liquid sludge, water, spent resin, spent filter cartridges, solid noncompactible and compactible trash, and other miscellaneous materials resulting from station and RF operation and maintenance. The operation of the system is described below.

11.2.4.1 **Solid Waste Handling Operations**

11.2.4.1.1 Expended Filter-Cartridge Handling Operations

Radioactive liquid service filters are removed from the system when the pressure drop across the filters becomes excessive or when the radiation level exceeds a predetermined maximum. The filter housing is surveyed prior to any opening or removal. After this is completed, the filter cover is remotely opened and removed by personnel using appropriate tools and protected by a filter removal shield, when required. A lead cask is placed over the filter housing and the filter is then moved upward into the lead cask. A drip pan is then secured to the bottom of the cask and the entire assembly is transported to the Surry Radioactive Waste Facility (SRF). The filter is placed in an approved container. The filter and container remain in the SRF until shipment to the burial site.

Surveys are conducted on the filter when the filter housing is opened, in the shielded casks, and when the container is transported to the Radwaste Facility or removed for shipment. The transport vehicle undergoes a complete radiological survey before leaving the site.

11.2.4.1.2 Spent Resin Handling Operations

A spent resin catch tank and spent resin blend tank are provided to receive spent resin from the station’s ion exchangers located in the Auxiliary Building. A transfer pump is associated with each tank. Spent resin is transferred from the blend tank to a high-integrity container for shipment to a burial facility. A shipping container may be sent to the Radwaste Facility for staging prior to shipment offsite.

Primary plant resins are directed to the spent resin catch tank. Resins from the catch tank are slurried to the blend tank to produce a mixture of resin whose contents may be shipped in a high integrity container. As an option, resin from the spent resin catch tank can be sluiced to a mobil resin transfer vessel (MRTV) for shielded transport to the Radwaste Facility. Subsequent to the processing operations, the lines are flushed with primary grade water.

Spent low-activity resins from the condensate polishing system are typically dewatered to acceptable strong tight containers and sent offsite for disposal. If the activity in these resins becomes high enough that the disposal site would not accept them in drums, the resins would be slurried to high integrity containers (HICs) and then dewatered prior to shipment to an offsite radwaste burial site. There is also an option to transport the spent condensate polishing resins to the Radwaste Facility. From the Radwaste Facility, condensate polishing resins can be sent to the bitumen solidification system, sent to a high integrity container filling and dewatering station, or proportionately blended with other resins for the purpose of lowering the dose rate of some higher activity resins.

11.2.4.1.3 Evaporator Concentrate Operations

Solids that are concentrated in the evaporator are discharged to the evaporator bottoms tank. These concentrates are at 25% by weight solids or at 24,500 ±5% ppm boron. Additionally, sludge from the suspended solids separator is periodically pumped to the bottoms tank.

The concentrates and sludges in the bottoms tank may be pumped to the waste batch tanks through heat traced lines where the concentrate waste is pretreated for processing by the solidification system.

In order to preclude plugging of the concentrates transfer piping, redundant heat tracing circuits are installed. Clean, hot water flushing connections are included to clean each line following concentrates transfer.

11.2.4.1.4 Solidification Operations (Installed but no longer used)

The bitumen solidification system incorporates a chemical and physical process for reducing the volume of radwaste and for incorporating the radwaste into a solidified bitumen matrix. The process uses a LUWA thin-film evaporator operating at a waste product outlet temperature of approximately 320°F. This results in the evaporation of free water from waste effluents and the remaining solids are incorporated in a bitumen matrix. Solidification of the end product occurs upon the natural cooling of the binder.

The system is capable of processing waste which includes evaporator concentrates and spent bead resin. Waste to be processed is collected in one of two waste batch tanks. The waste is sampled and chemically pretreated to prepare it for processing.

The conditioned waste is fed at a controlled rate to a thin film evaporator. Molten bitumen is simultaneously fed into the evaporator through a second feed nozzle. The evaporator is heated by means of hot thermal fluid flowing through an external jacket. As the waste flows downward through the evaporator, the water is evaporated and the water vapor flows counter-currently upward and out of the evaporator. The waste solids are mixed with molten bitumen and exit the bottom of the evaporator, flowing into a waste container. Upon cooling, the waste/bitumen mixture solidifies into a freestanding, monolithic solid with free liquids less than 0.5 percent by volume of the waste form.

The water vapor leaving the thin film evaporator is condensed in a shell and tube condenser. The condensate flows into the distillate oil separator. When this tank is filled, the distillate is pumped to a liquid waste collection tank.

The bituminized waste product flows from the discharge valve of the thin film evaporator into a 55-gallon steel drum. Once filled and cooled, drums are inspected for free liquid, capped, smeared and surveyed. The drums are then transferred to the RF storage area to await shipment to a licensed disposal contractor.

Figure 11.2-5 depicts the solidification process flow.

11.2.4.1.5 Ultimate Disposal Operations

All packages containing radioactive nonfissionable material, and the procedures used to prepare these for offsite shipment, are in accordance with U. S. Department of Transportation regulations. The Radwaste Facility, Low-Level Waste Storage Facility and Sea Van Storage Pad are facilities used for the storage of radioactive material. All waste material is transferred either to a licensed disposal or processing contractor or to common carrier for delivery to a licensed disposal or processing contractor. Radwaste shipments fall under the purview of Vepco's procedures and quality assurance program.

11.2.4.2 **Components**

All components listed below except the spent resin catch tank, the spent resin blend tank, and their associated pumps are located within the Radwaste Facility.

11.2.4.2.1 Spent Resin Catch Tank
Spent Resin Blend Tank

One of each tank is provided. Each tank is installed in a separate cubicle on Elevation 6 ft. 10 in. in the Decontamination Building. The normal operating volume (high level to low level) is approximately 214 ft^3. Total usable volume is approximately 245 ft^3. Vessels are designed to ASME Section VIII.

11.2.4.2.2 Spent Resin Catch Tank Transfer Pump
Spent Resin Blend Tank Transfer Pump

One of each pump is provided. Pumps are of the progressive cavity design. Each pump is designed to deliver 27.7 gal/100 rpm at 0 psi.

11.2.4.2.3 Evaporator Bottoms Tank

The evaporator bottoms tank is a 5000-gallon, 11-foot diameter, vertical tank with a dished bottom and a flat top. The tank is constructed of Inconel 625 and is equipped with a mixing eductor and a demineralizer water flush header, level indication, and heat tracing. The heat tracing prevents concentrates from solidifying in the tank.

11.2.4.2.4 Spent Resin Collection Tanks

There are four spent resin collection tanks in the Radwaste Facility. These tanks are 1020-ft^3 capacity, vertical tanks with a 10-foot diameter. Each tank is constructed of 304 stainless steel and is designed for atmospheric pressure. Each tank is equipped with mixing lines, flush lines, decant lines and an overflow. Each of the two mixing lines is attached to internal mixing eductors.

11.2.4.2.5 Spent Resin Collection Tank Pumps

There are two spent resin collection tank pumps each of which is capable of pumping from any of the four spent resin collection tanks. Each pump is rated at 440 gpm at a total dynamic head of 86 psi. Parts of the pumps in contact with the radioactive resin/water slurry are made of stainless steel.

11.2.4.2.6 Waste Batch Tanks

There are two 1000-gallon waste batch tanks. Each tank is constructed of 316L stainless steel and is equipped with external heating elements to prevent the solidification of evaporator concentrates. Each tank has mechanical agitators for mixing.

11.2.4.2.7 Bitumen Storage Tank

The bitumen storage tank is a horizontal 6000-gallon carbon steel tank. The tank has an internal electric heater and is heavily insulated. The tank is equipped with instrumentation for tank level and temperature.

11.2.4.2.8 Bitumen Metering and Transfer

Bitumen is metered by a gear type metering pump capable of accurate control of the bitumen feed between 0.04-0.92 gpm. The piping from the storage tank to the thin film evaporator are not heat traced. Instead, transfer lines are jacketed pipes using the heating oil from the thin film evaporator heating system to maintain flow of the bitumen feed.

11.2.4.2.9 Thin Film Evaporator

The thin film evaporator is a LUWA design capable of a 52-gal/hr evaporation rate. The body of the evaporator is made of 316L stainless steel. The internal paddle assembly in the evaporator continuously spreads the feed material into a thin film along the vessel walls to assist in the evaporation. The constant action of the paddle assembly also assures adequate and uniform mixing of the waste and the bitumen binder. The paddle assembly is turned by a 15 hp electric motor.

11.2.4.2.10 Distillate Oil Separator Tank

Water vapor from the thin film evaporator is condensed and collected in the distillate oil separation tank. Due to the use of bitumen in this process, small amounts of light weight oils are volatilized during the evaporator process. These oils are separated in the distillate oil separation tank and are skimmed off for separate treatment. The condensed water in the tank sent to the liquid waste collection tanks via the distillate transfer pump.

11.2.5 Gaseous Waste Disposal System

The process vent subsystem regulates the discharge of potentially high-activity waste gases to the atmosphere. The ventilation vent subsystem described in Section 9.13 and the RF vent described in 11.2.2 regulate the discharge of potentially low-activity air streams to the atmosphere. Radioactive waste discharges from these subsystems are monitored by particulate and gas monitors that are part of the process radiation monitoring system described in Section 11.3.3. Limitations on gaseous releases, and associated reporting requirements, are included in the Technical Specifications and the Offsite Dose Calculation Manual.

Waste gases, primarily hydrogen, nitrogen, and minor amounts of fission product gases, such as xenon and krypton, are removed from reactor coolant letdown by the stripper in the boron recovery system. The stripped gases are processed in the gaseous waste disposal system.

The gaseous waste disposal system is designed to provide adequate radioactive decay storage time for the waste gases and, in addition, provide long-term holdup of these gases when high-flow letdown is required.

Gases pass from the stripper to the stripper surge tank, where they are compressed. From the surge tank, the gases are bled off to the waste gas surge drum. At a pressure of approximately 1 atm, the waste gas diaphragm compressor transfers the gases to one of two waste gas decay tanks.

When released, effluent from the waste gas decay tanks is mixed with dilution air, effluent from the containment vacuum system, and the aerated vents from the vent and drain system. The combined gaseous waste is filtered through charcoal and high-efficiency particulate air (HEPA) filters before being released to the atmosphere. The process vent blowers maintain a small vacuum in the charcoal filters to prevent outleakage from the filter assembly. The decay tank contents are sampled before any release to the process vent.

11.2.5.1 **Process Vent Subsystem**

Gaseous wastes enter the process vent subsystem from the gaseous waste disposal system, the stripper in the boron recovery system, the vent and drain system, various pressure relief valves, and the containment vacuum system, as shown in Reference Drawings 4 and 5.

A catalytic recombiner system is installed (but not used) as part of the gaseous waste disposal system. A summary description of the catalytic recombiner is provided in Section 11.2.5.3.1.

Two double-walled waste gas decay tanks are provided. Each tank is buried beneath the Waste Gas & Boron Recovery Pump House and receives tornado protection from this building within its footprint. Where the tanks extend outside the footprint of this building, tornado protection is provided by the depth of burial in soil. The inner tank is fabricated from austenitic stainless steel in accordance with Section III.C of the ASME Code, and the outer tank from carbon steel, in accordance with Section VIII of the ASME Code. Sampling connections are provided for the tank contents and for leakoff in the annular intercept space between the tanks. The decay tanks have piping connections for parallel operation with alternate feed and bleed.

Overpressure relief protection is provided at the waste gas decay tanks in accordance with Section III.C of the ASME Code. The protective devices consist of bellows-sealed pressure relief valves followed by rupture disk assemblies. The use of bellow seals and rupture disks precludes the leakage of the waste gas to the environment during normal operation of the gaseous waste disposal system. The piping downstream of the protective devices relieves to the process vent through the radiation monitor station.

Effluent from the waste gas decay tanks is mixed with dilution air, effluent from the containment vacuum system, and the aerated vents from the vent and drain system. The combined gaseous waste is filtered through charcoal filters before being released to the atmosphere. The process vent blowers maintain a small vacuum in the charcoal filters to prevent outleakage from the filter assembly. The decay tank contents are sampled before any release to the process vent.

The entire discharge stream of radioactive letdown gas and dilution air is monitored for flow rate, pressure, temperature, and particulate and gaseous activity before release through the process vents. The total flow is regulated by a flow control valve on the process vent blower. The ratio of dilution air to waste gas letdown flow is such that the mixed streams never enter the flammability region of the air-steam-hydrogen phase diagram.

The process vent and the process vent blowers are sized such that the minimum exit velocity is approximately 100 fps. This exit velocity prevents any significant downdrafting of the effluent. The process vent terminates at an elevation approximately 22 feet above the top of one of the containment structures.

The process vent monitors are set such that the effluent activity release rate results in concentrations less than those limits provided in the revision of 10 CFR 20 to which the plant was originally licensed. In the event that the activity of the effluent stream exceeds the setting of the monitors, the process vent control station automatically terminates the release of waste effluents from the waste gas decay tanks and isolates the containment vacuum system from the process vent sub system. The monitor also activates an alarm in the control room before valve closure if the activity approaches a preset value. Subsequent restart of the system is manual, in accordance with procedures. The discharge of gases from the waste gas decay tanks is initiated and controlled separately.

The gaseous waste disposal system is designed to provide adequate radioactive decay storage time for the waste gases and, in addition, to provide long-term holdup of these gases when high-flow letdown is required.

The combined volume of the two waste gas decay tanks is sized to process the gas stripped from the estimated annual average letdown flow of 17 gpm, based on simultaneous operation of two reactor units.

The average gas stripping rate is a function of the average letdown flow rate, and this flow rate is dependent on the assumed plan of operation as described in Section 9.2.

On this basis, the total annual letdown volume for two units is 8.94×10^6 gal, and the average annual letdown flow rate for two units is 17 gpm.

If the hydrogen volume is assumed to be 35 cm^3/kg and 90% of the total gas volume, then the hydrogen stripping rate at an annual average of 17-gpm letdown is 0.0792 scfm and the total gas stripping rate is 0.088 scfm.

The gas decay tanks are sized so that a 17-gpm letdown rate with the recombiner not operating gives an average holdup time equivalent to approximately 5 half-lives of Xe-133 (30 days).

Assuming 1% failed fuel, the estimated curies of each radionuclide released from the station via the gaseous waste disposal system for the original plant design are listed in Tables 11.2-2 and 11.2-3. Table 11.2-2 is for a waste gas cycle with the recombiner not operating, which is the design basis for the system, and Table 11.2-3 is for a waste gas cycle with the recombiner operating. With the recombiner not operating, the gas cycle is 30 days of feed/20 days of decay/10 days of bleed; most of the gas is hydrogen. With the recombiner operating, the feed portion of the waste gas cycle can vary between 30 days and approximately 300 days, the time needed to reach maximum design pressure in the tank. To be conservative, 300 days of feed was chosen as the basis for Table 11.2-3, and the waste gas cycle considered was 300 days of feed/20 days of decay/10 days of bleed.

In each case, it is assumed that all of the gases and 0.1% of the iodines are removed at the gas stripper and sent to the waste gas decay tanks except for hydrogen in the case with the recombiner operating. The system is operated so that one tank is on the feed portion of the cycle while the other is on the decay and bleed portion.

The equilibrium reactor coolant activity is a function of the waste gas removal rate by the gas stripper. Using the parameters listed in Table 9.1-5 and a 17-gpm letdown rate to the gas stripper, the equilibrium coolant activity for each radionuclide was calculated. These are also listed in Tables 11.2-2 and 11.2-3.

As can be seen from these tables, the yearly dose at the site boundary is about 0.019 rem for continuous operation with a 30 days of feed/20 days of decay/10 days of bleed cycle, and about 0.007 rem for the 300 days of feed/20 days of decay/10 days of bleed cycle. Both of these values are well below the member of the public dose limit of 0.5 rem/yr set forth in the revision of 10 CFR 20 to which the plant was originally licensed.

11.2.5.2 Ventilation Vent Subsystem

The ventilation vent subsystem is considered to be a portion of the gaseous waste disposal system only for purposes of radiological surveillance, and it is designed on this basis. However, since it handles air streams of very low activity levels, and since the gases to be handled are predominantly of nonradioactive origin, this subsystem has been considered as an auxiliary system for the purpose of this report. A full description of this subsystem is included in Section 9.13.

11.2.5.3 Components

The major components of the gaseous waste disposal system are described below.

11.2.5.3.1 Catalytic Recombiner (Installed But Not Usable)

One skid-mounted catalytic recombiner system is provided. The system includes duplicate full-capacity recycle compressors, duplicate full-capacity electrical preheaters, duplicate full-capacity catalytic recombiners, one aftercooler condenser, one moisture separator, one electrical reheater, duplicate hydrogen analyzers of the thermal conductivity type for the recombiner influent and effluent, duplicate oxygen analyzers of the paramagnetic type on the recombiner effluent, a single oxygen analyzer on the recombiner influent, and one bleed stream cooler. The recombiner system operates at approximately 22 psia and has a feed capacity of approximately 1.14 scfm. The diluent is nitrogen. The catalytic recombiner system is designed according to Section III.C of the ASME Code.

The recycle compressors are rotary positive blowers designed to circulate 40 cfm at 8 psig discharge pressure. They are of gas-tight construction, with three mechanical shaft seals in series between the circulating gas and the outside atmosphere. The end bell of the compressor is pressurized with nitrogen as a further precaution against outward leakage.

The preheaters are stainless steel pipes with external electrical heating elements and are used to raise the temperature of the recycle stream to 300°F before the recycle stream enters the catalyst bed.

The catalytic recombiners are all-metal, low-halogen catalysts. Each bed contains miles of crimped-nickel alloy ribbon coated with catalytically activated precious metals, mainly palladium and platinum.

The aftercooler condenser is a pipe-within-a-pipe heat exchanger, with the recycle gas flowing through the inner pipe and component cooling water flowing through the outer pipe. The aftercooler condenser condenses the water vapor by cooling the recycle gas stream and lowering the water vapor in it to a dewpoint of 75°F.

The moisture separator is a centrifugal separator with an automatic drain operated by a level controller and has high- and low-level alarms. Moisture from the moisture separator drains to a high-level waste drain tank.

The reheater is similar to the preheaters, and raises the temperature of the recycle stream to 120°F.

The hydrogen analyzers are of the thermal conductivity type; the oxygen analyzers are of the paramagnetic type.

11.2.5.3.2 Waste Gas Surge Tank

One waste gas surge tank with a 15.7 ft^3 capacity is provided. This tank is operated at a pressure of approximately 10 to 20 psia. The tank is fabricated from austenitic stainless steel in accordance with Section III.C of the ASME Code.

11.2.5.3.3 Waste Gas Compressor

Two waste gas compressors of the diaphragm type are provided. Each has a rated capacity of 1.5 scfm at a discharge pressure of 120 psig. The compressor heads are leak tested to ensure that the leakage does not exceed a predetermined amount.

11.2.5.3.4 Waste Gas Decay Tank

Two buried waste gas decay tanks are provided. These tanks have double-wall construction with feed and bleed lines; sample, nitrogen purge, drain, and relief valve lines to the inner tank; and sample, nitrogen purge, drain, and relief valve lines from the outer tank. An access opening is provided to the inner tank. In addition, adequate grounding and corrosion protection are provided. The inner tank is fabricated from stainless steel in accordance with Section III.C of the ASME Code, and the outer tank from carbon steel in accordance with Section VIII of the ASME Code.

To ensure an explosive gas mixture does not develop in the tanks, samples are taken via the oxygen analyzer. Compressors have been installed as sample pumps but are normally isolated and bypassed. The differential pressure between the waste gas decay tank and the waste gas surge drum is used to induce flow through the oxygen analyzer.

11.2.5.3.5 Process Vent Blowers

Two full-capacity dilution air blowers of 300 cfm capacity at 2 psia are provided. The blowers are of a centrifugal type, located in a field fabricated box with the blower suction from the box’s interior. Some inleakage is tolerated.

11.2.5.3.6 Charcoal Filters

Two charcoal filter beds are provided to service approximately 300-scfm radioactive gas. The filters are maintained at a subatmospheric pressure.

11.2.5.3.7 Postaccident Radiation Waste Connection

The capability for processing highly radioactive postaccident gaseous waste has been incorporated into the gaseous waste disposal system. A flanged connection (Reference Drawings 4 & 5) is located in the vicinity of the boron recovery tanks for the purpose of discharging radioactive gases to an external process system without requiring personnel to enter high radiation areas. The external process system would be brought onsite, if needed, following an accident. The postaccident radiation waste connection also has an isolation valve that can be operated by reach rod to further minimize personnel exposure.

11.2.6 Tests and Inspections

11.2.6.1 Construction and Fabrication

During the manufacturing period, Vepco's inspectors inspected all equipment periodically, as required, to ensure that all equipment had been provided in strict accordance with specifications. Shop hydrostatic and performance tests of principal equipment were witnessed by Vepco's inspectors. Certified code inspection data sheets were provided by manufacturers for all equipment covered by ASME or other applicable codes.

During the construction period, all pressure systems were subjected to field hydrostatic or pneumatic tests to verify the integrity of welded connections and to ensure that the system as a whole functioned as intended.

During the preliminary operation period, all equipment in the waste disposal system was tested to verify conformance with specification performance requirements. All control systems and interlocks were tested and operated to ensure satisfactory functional performance and reliability.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

On February 9 and 10, 1971, a performance test of the waste disposal system catalytic recombiner was conducted to demonstrate the actual catalyst performance over a range of operating conditions. Tests were rerun at three hydrogen inlet concentrations: test 1, 2.0% hydrogen; test 2, 0.5% hydrogen; and test 3, 3.2% hydrogen.

The specified test requirements at each test condition were to maintain the outlet oxygen concentration at no more than 1% and to have less than 100 ppm of hydrogen in the outlet.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The catalyst efficiency was greater than 99.5% over the range of hydrogen flow rates and concentrations tested. The outlet hydrogen and oxygen concentrations were well within the stated limits. The tests confirmed the capability of the recombiner to operate over the range of operating conditions expected during normal operations.

11.2.6.2 **Operation**

The basic function of the waste disposal system is to release controlled amounts of radioactivity to the environment with no undue effects on the health and safety of the general public. This is accomplished by ensuring that all releases from the station are at less than the maximum levels of radioactivity set by applicable regulatory agencies, as given in Section 11.2.1.

The following is a list of the types and areas monitored to ensure the proper functioning of the waste disposal system:

1. Continuous Process Monitoring: As described in Section 11.3.3, process radiation monitors continuously monitor certain key systems where radioactive material may exist. These monitors give an indication of the waste-processing requirements of certain systems.
2. Batch Sample Process Monitoring: As described in Section 9.6, batch samples, obtained from certain subsystems, provide information on the effectiveness of ion exchangers, filters, and evaporators. This gives an indication of the effectiveness of the various waste processing subsystems. The monitoring of the gas in the waste gas holdup tanks avoids the storage of excessive activity.
3. Continuous Monitoring of Discharge Effluents: As described in Section 11.3.3, radiation monitors continuously monitor discharges from the process and ventilation vent systems and RF systems and the liquid waste disposal and service water systems. These monitors give an indication of liquid and gaseous radiation discharges to the environment and provide alarms with automatic valve closure when radiation levels exceed a preset level, thus terminating discharge.
4. Radiation Survey of Radioactive Waste/Material Containers: Radiation surveys and smear samples are taken of shipping casks, drums, etc., that contain radioactive waste/material to ensure that such waste/material is properly contained and meets transportation regulations.
5. Environmental Monitoring: As described in Section 11.3.5, environmental samples are taken to indicate the effect of liquid and gas discharges on the environment and the compliance of these discharges with applicable regulations.

To ensure that the performance of the waste disposal systems is meeting design criteria, the following checks are made:

1. Standardized laboratory radiochemical analytical procedures are used to verify decontamination factors.
2. Radiation monitors are periodically checked with remotely operated check sources. The Local Processing Units (LPUs) of the MGP Instruments (MGPI) monitors perform various self checks automatically. Their electrical self check introduces a known and fixed level of pulses into the electronics excluding the detector and verifies that the response is correct, otherwise a fault is generated. Additionally, the electronics continuously monitor the detector for a minimum countrate, otherwise a fault alarm is generated. In addition, samples are withdrawn from the process streams being monitored and analyzed to ensure compliance with regulatory limits. Those monitors that actuate control valves by a high radiation signal are periodically tested to ensure the valves activate on alarm signal.
3. Portable survey instruments and laboratory analytical instruments are periodically calibrated with known radiation sources in accordance with station health physics procedures.
4. Radiation levels on the outside of components, pumps, valves, and piping in the waste disposal systems are monitored periodically to avoid inadvertent discharge of activity that may accumulate with time.

11.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-083C	Flow/Valve Operating Numbers Diagram: Vent and Drain System, Unit 1
2.	11448-FM-30B	Flow Diagram: Waste Disposal System
3.	11448-FM-30C	Flow Diagram: Waste Disposal System
4.	11448-FM-090A	Flow/Valve Operating Numbers Diagram: Gaseous Waste Disposal System, Unit 1
5.	11448-FM-090B	Flow/Valve Operating Numbers Diagram: Gaseous Waste Disposal System, Unit 1

Table 11.2-1
WASTE DISPOSAL SYSTEMS DESIGN DATA

Spent Resin Catch Tank (1-LW-TK-14)	
Number	1
Capacity	1955 gal
Operating capacity	214 ft^3
Design pressure	150 psig
Design temperature	200°F
Operating pressure	Atmospheric
Operating temperature	60-120°F
Material	SS, SA-240, 316L
Design code	ASME VIII, D.V.
Spent Resin Blend Tank (1-LW-TK-15)	
Number	1
Capacity	1955 gal
Operating capacity	214 ft^3
Design pressure	150 psig
Design temperature	200°F
Operating pressure	Atmospheric
Operating temperature	60-120°F
Material	SS, SA-240, 316L
Design code	ASME VIII, D.V.
High-level Waste Drain Tank	
Number	2
Capacity (each)	2390 gal
Operating capacity (each)	2000 gal
Design pressure	25 psig
Design temperature	200°F
Operating pressure	Atmospheric
Operating temperature	120°F
Material	SS Type 316
Design code	ASME III.C
Low-Level Waste Drain Tank	
Number	2
Capacity (each)	2874 gal
Operating capacity (each)	1785 gal
Design pressure	25 psig
Design temperature	200°F
Operating pressure	Atmospheric
Operating temperature	120°F

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Low-Level Waste Drain Tank (continued)			
Material	SS Type 316		
Design code	ASME III.C		
Contaminated Drains Collection Tanks			
Number	2		
Capacity (each)	1230 gal		
Operating Capacity (each)	1045 gal		
Design pressure	25 psig		
Design temperature	200°F		
Operating pressure	Atmospheric		
Operating temperature	120°F		
Material	SS Type 304		
Design code	ASME VIII		
Liquid Waste Test Tanks (installed but no longer used)			
Number	2		
Capacity (each)	3000 (usable) gal		
Design pressure	25 psig		
Design temperature	212°F		
Operating pressure	Atmospheric		
Operating temperature	140°F		
Material	SS Type 304		
Design code	ASME VIII		
Waste Gas Catalytic Recombiner (installed but no longer used)			
Number	1		
Capacity, feed	1.31 scfm		
Design feed pressure	22 psia		
Design feed temperature	70-120°F		
Feed composition, scfm	Max.	Avg.	Min.
H_2	1.14	0.0805	0
H_20	0.04	0.026	0
Xe	Trace		
Kr	Trace		
N_2	0.130	0.00922	0
Design bleed pressure	14.0 psia		
Design H_2 bleed concentration	0.1% max.		
Design bleed volume	10% of feed		
Design code	ASME III.C		

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Waste Gas Decay Tanks		
Number	2	
Capacity (each)	434 ft^3	
Design pressure	Outer Tank	Inner Tank
	From 30 in. Hg vacuum to 150 psig	From 30 in. Hg vacuum to 150 psig
Design temperature	200°F	200°F
Operating pressure	Atmospheric	115 psig
Operating temperature	120°F	140°F
Material	Carbon	SS Type 304L
Design code	ASME VIII	ASME III.C
Earthquake design	Complies with Class I requirements	
Waste Gas Surge Tank		
Number	1	
Capacity	15.7 ft^3	
Design pressure	From 30 in. Hg vacuum to 30 psig	
Design temperature	300°F	
Operating pressure	15 psig	
Operating temperature	120°F	
Material	SS Type 304	
Design code	ASME III.C	
Low-level Waste Drain Pumps		
Number	2 (1 required)	
Type	Horizontal centrifugal	
Motor horsepower	7.5 hp	
Seal type	Double mechanical	
Capacity (each)	120 gpm	
Head at rated capacity	94 ft	
Design pressure	150 psig	
Materials		
Casing	SS Type 316	
Shaft	A 5564, Type 630	
Impeller	SS Type 316	
High-level Waste Drain Pumps		
Number	2 (1 required)	
Type	Horizontal centrifugal	
Motor horsepower	7.5 hp	
Seal type	Double mechanical	
Capacity (each)	120 gpm	

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

High-level Waste Drain Pumps (continued)	
Head at rated capacity	86 ft
Design pressure	150 psig
Materials	
Pump casing	SS Type 316
Shaft	A564, Type 630
Impeller	SS Type 316
Contaminated Drains Transfer Pumps	
Number	2 (1 required)
Type	Horizontal centrifugal
Motor horsepower	10 hp
Seal type	Mechanical
Capacity (each)	75 gpm
Head at rated capacity	166 ft
Design pressure	150 psig
Materials	
Pump casing	SS Type 316
Shaft	A564, Type 630
Impeller	SS Type 316
Spent Resin Catch Tank Transfer Pump (1-LW-P-12)	
Number	1
Type	Progressive cavity
Capacity	27.7 gal/100 rpm @ 0 psi
Design pressure	100 psig
Design temperature	150°F
Material	SS Type 316
Design Code	None
Spent Resin Blend Tank Transfer Pump (1-LW-P-13)	
Number	1
Type	Progressive cavity
Capacity	27.7 gal/100 rpm @ 0 psi
Design pressure	100 psig
Design temperature	150°F
Material	SS Type 316
Design Code	None

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Process Vent Blower	
Number	2 (1 required)
Type	Multistage centrifugal
Motor horsepower	7.5 hp
Capacity (each)	300 scfm
Differential pressure	2 psi
Suction pressure	14.0 psia
Design pressure	15 psig
Materials	
Casing	Cast iron
Impeller	Aluminum
Shaft	SS Type 304
Waste Gas Compressor	
Number	2 (1 required)
Type	Diaphragm
Motor horsepower	1.5 hp
Capacity (each)	1.5 scfm
Discharge pressure at rated capacity	120 psig
Design pressure	220 psig
Materials	
Cylinder	Carbon steel
Piston rod	Forged steel
Piston	Nodular iron
Diaphragms and parts contacting waste gas	SS Types 304/316
Low-Level Waste Drain Filter (installed but no longer used)	
Number	1
Retention size, microns	5
Filter element material	Fibre
Capacity normal	50 gpm
Capacity maximum	75 gpm
Material	SS Type 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III.C
High-level Waste Drain Filter (installed but no longer used)	
Number	1
Retention size, microns	5
Filter element material	Fibre
Capacity normal	50 gpm

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

High-level Waste Drain Filter (installed but no longer used) (continued)	
Capacity maximum	75 gpm
Material	SS Type 304
Design pressure	150 psig
Design temperature	250°F
Design code	ASME III.C
Contaminated Drains Filters (installed but no longer used)	
Number	2 (1 required)
Filter element material	Porous stone media
Capacity normal	50 gpm
Material	SS Type 304
Design pressure	150 psig
Design temperature	120°F
Design code	ASME VIII
Liquid Waste Collection Tank	
Number	2
Capacity	30,000 gal
Design pressure	Atmospheric Plus Content
Design temperature	150°F
Operating pressure	Full of water
Operating temperature	104°F
Material	SS 316L
Design code	ASME III
Liquid Waste Surge Tanks	
Number	2
Capacity	30,000 gal
Design pressure	Atmospheric Plus Content
Design temperature	150°F
Operating pressure	Full of water
Operating temperature	104°F
Material	SS 316L
Design code	ASME III
Liquid Waste Collection Tank Pumps	
Number	2
Type	Centrifugal
Motor horsepower	15 hp
Seal type	Double Mechanical
Capacity (each)	300 gpm

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Liquid Waste Collection Tank Pumps (continued)	
Head at rated capacity	74 ft
Design pressure	142.2 psig
Materials	
Casing	SS 316
Shaft	SS 316
Impeller	SS 316
Liquid Waste Surge Tank Pumps	
Number	2
Type	Centrifugal
Motor horsepower	15 hp
Seal type	Double Mechanical
Capacity (each)	300 gpm
Head at rated capacity	74 ft
Design pressure	142.2 psig
Materials	
Casing	SS 316
Shaft	SS 316
Impeller	SS 316
SPI Suspended Solids/Oil Separator	
Number	2
Design capacity	30 gpm (each)
Design pressure	Atmospheric
Design temperature	150°F
Material	SS 316L
Separation area, equiv.	8 ft^2 (each)
Design code	ASME III
Liquid Waste Transfer Pumps	
Number	2
Type	Centrifugal
Motor horsepower	10 hp
Seal type	Double Mechanical
Capacity (each)	40 gpm
Heat at rated capacity	200 ft
Design pressure	142.2 psig
Materials	
Casing	SS 316
Shaft	SS 316
Impeller	SS 316

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Liquid Waste Filter/liquid Waste Oil Filter	
Number	1
Retention size, microns	N/A
Filter element material	Charcoal
Capacity normal	60 gpm
Capacity maximum	60 gpm
Material	SS 316L
Design pressure	200 psig
Design temperature	150°F
Design code	ASME VIII
Evaporator Recirculation Pump	
Number	1
Type	Axial Flow
Motor horsepower	75 hp
Seal type	Double Mechanical
Capacity (each)	9000 gpm
Head at rated capacity	15 ft
Design pressure	60 psig
Materials	
Casing	Alloy 20
Shaft	Alloy 20
Impeller	Alloy 20
Oil Drain Tank	
Number	1
Capacity	1070 gal
Design pressure	Atmospheric Plus Water Full
Design temperature	150°F
Operating pressure	Full of Content
Operating temperature	104°F
Material	SS 316L
Design Code	ASME III
Vapor Recompressor	
Number	1
Type	Centrifugal
Motor horsepower	600 hp
Seal type	Labyrinth
Capacity (each)	7904 ACFM
Compression Ratio	1.97
Design pressure	150 psig

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Vapor Recompressor (continued)		
Materials		
Casing	SS 316L	
Shaft	SS 316L	
Impeller	SS 316L	
Distillate Flash Tank		
Number	1	
Capacity	150 gal	
Design pressure	30 psig	
Design temperature	300°F	
Operating pressure	0.5 psig	
Operating temperature	212°F	
Material	SS 316L	
Design Code	ASME VIII	
Distillate Subcooler		
Number	1	
Total duty	1,589,994 Btu/hr	
	Shell	Tube
Design pressure	150 psig	75 psig
Design temperature	250°F	300°F
Operating pressure	60 psig	52 psig
Operating temperature, in/out	80/92.5°F	212/120°F
Material	SS 304/Tube Side Carbon Steel/Sheet Side	
Fluid	Cooling Water	Distillate
Design code	ASME VIII	
Evaporator Heater		
Number	1	
Total duty	17,787,245 Btu/hr	
	Shell	Tube
Design pressure	50 psig	45 psig
Design temperature	300°F	300°F
Operating pressure	15 psig	5 psig
Operating temperature, in/out	247.8/247.8°F	218.3/222.3°F
Material	SS 316L/Alloy 20	Inconel 625
	Shell	Tube
Fluid	Steam	Liquid Waste
Design code	ASME VIII	

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Liquid Waste Monitor Tanks	
Number	2
Capacity	15,000 gal
Design pressure	Atmospheric Plus Contents
Design temperature	150°F
Operating pressure	Full of Water
Operating temperature	104°F
Material	SS 304
Design Code	ASME III
Liquid Waste Monitor Tank Pumps	
Number	2
Type	Centrifugal
Motor horsepower	60 hp
Seal type	Single Mechanical
Capacity (each)	330 gpm
Head at rated capacity	326 ft
Design pressure	275 psig
Materials	
Casing	316 SS
Shaft	Steel
Impeller	316 SS
Laundry Drain Pre-filters	
Number	2
Rentention size	50 microns
Filter element material	Bag
Capacity, normal	50 gpm
Capacity maximum	50 gpm
Material	SS 304
Design pressure	150 psig
Design temperature	150°F
Design Code	ASME VIII
Laundry Drain Filter	
Number	1
Rentention size, microns	N/A
Filter element material	Polyester
Capacity, normal	50 gpm
Capacity maximum	50 gpm
Material	SS 304
Design pressure	150 psig

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Laundry Drain Filter (continued)	
Design temperature	150°F
Design Code	ASME VIII
Laundry Drain Monitor Tank	
Number	2
Capacity	7500 gal
Design pressure	Atmospheric Plus Content
Design temperature	150°F
Operating pressure	Full of Water
Operating temperature	104°F
Material	SS 304
Design Code	ASME III
Laundry Drain Monitor Pump	
Number	2
Type	Centrifugal
Motor horsepower	40 hp
Seal type	Single Mechanical
Capacity (each)	140 gpm
Head at rated capacity	310 ft
Design pressure	225 psig
Materials	
Casing	Ductile Iron
Shaft	Steel
Impeller	Cast Iron
Evaporator Bottoms Tank	
Number	1
Capacity	5000 gal
Design pressure	Atmospheric Plus Contents
Design temperature	275°F
Operating pressure	Full of Water
Operating temperature	212°F
Material	Inconel 625
Design Code	ASME III
Evaporator Bottoms Tank Pump	
Number	1
Type	Centrifugal
Motor horsepower	7.5 hp
Seal type	Double Mechanical
Capacity (each)	165 gpm

Table 11.2-1 (CONTINUED)
WASTE DISPOSAL SYSTEMS DESIGN DATA

Evaporator Bottoms Tank Pump (continued)	
Head at rated capacity	60 ft
Design pressure	142.2 psig
Materials	
Casing	SS 316
Shaft	SS 316
Impeller	SS 316
Evaporator Bottoms Tank	
Number	1
Capacity	5000 gal
Design pressure	Atmospheric Plus Contents
Design temperature	275°F
Operating pressure	Full of Water
Operating temperature	180°F
Material	Inconel 625
Design code	ASME III
Liquid Waste Demineralizer Vessels	
Number	3
Capacity	29 ft^3
Design flow	30 gpm
Design pressure	150 psig
Material	SS 304
Design code	ASME VIII
RF Liquid Waste Reverse Osmosis Unit	
Number	1
Capacity	25 gpm
Materials	SS, PVC
Pressure rating	150 psig (low pressure portion) 500 psig (high pressure portion)
Design code	ANSI B31.1
Distillate Demineralizers	
Number	1
Capacity	50 ft^3
Design flow	30 gpm
Distillate Demineralizers (continued)	
Design pressure	150 psig
Material	SS 304
Design code	ASME VIII

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 11.2-2

ESTIMATED WASTE GAS RELEASE WITH RECOMBINER NOT OPERATING

Based on gaseous activity from:

a. Waste gas cycle: 30 days of feed/20 days of decay/10 days of bleed.
b. Two units, 2546 MWt each.
c. 1% failed fuel.
d. 17-gpm total letdown flow rate to gas stripper from both units.
e. 100% of gases and 0.1% of iodines removed in gas stripper.
f. X/Q - 7.5×10^{-6} sec/ m^3 for calculating dose at site boundary.

Nuclide	Equilibrium Coolant Activity ($\mu Ci/cm^3$)	Curies In Tank At End Of Feed Cycle	Curies In Tank After 20 Days Decay	Discharge Rate (Ci/sec) Initial	Discharge Rate (Ci/sec) Final	Curies Discharged In One Cycle	Total Curies Discharged Per Year	Dose At Site Boundary (rem/yr)
Kr-85m	1.22	3.63×10^{1}	2.05×10^{-35}	2.14×10^{-41}	1.61×10^{-59}	4.44×10^{-37}	5.40×10^{-36}	6.4×10^{-42}
Kr-85	3.25×10^{-1}	1.25×10^{3}	1.25×10^{3}	1.30×10^{-3}	1.30×10^{-3}	1.12×10^{3}	1.36×10^{4}	5.4×10^{-3}
Kr-87	8.27×10^{-1}	7.96	0	0	0	0	0	0
Kr-88	2.36	4.92×10^{1}	0	0	0	0	0	0
Xe-131m	4.62×10^{-2}	1.95×10^{2}	6.16×10^{1}	6.43×10^{-5}	3.61×10^{-5}	4.22×10^{1}	5.13×10^{2}	1.6×10^{-4}
Xe-133m	1.33	5.41×10^{2}	1.30	1.36×10^{-6}	6.66×10^{-8}	3.70×10^{-1}	4.50	1.8×10^{-6}
Xe-133	80.9	7.52×10^{4}	5.47×10^{3}	5.71×10^{-3}	1.54×10^{-3}	2.75×10^{-3}	3.35×10^{4}	1.3×10^{-2}
Xe-135m	7.13×10^{-1}	1.40	5.70×10^{-25}	5.95×10^{-31}	1.02×10^{-41}	2.07×10^{-26}	2.52×10^{-25}	3.0×10^{-31}
Xe-135	3.39	2.27×10^{2}	2.80×10^{-14}	2.92×10^{-20}	3.24×10^{-28}	1.38×10^{-15}	1.68×10^{-14}	1.9×10^{-20}
Xe-138	4.50×10^{-1}	9.59×10^{-1}	0	0	0	0	0	0
1-131	1.72	2.29×10^{-1}	4.11×10^{-2}	4.28×10^{-8}	1.81×10^{-8}	2.48×10^{-2}	3.01×10^{-1}	1.2×10^{-3}
1-132	5.85×10^{-1}	1.00×10^{-3}	0	0	0	0	0	0
1-133	2.65	4.15×10^{-2}	5.44×10^{-9}	5.68×10^{-15}	2.06×10^{-18}	6.19×10^{-10}	7.53×10^{-9}	7.9×10^{-12}
1-134	3.61×10^{-1}	2.35×10^{-4}	0	0	0	0	0	0
1-135	1.40	7.01×10^{-3}	2.03×10^{-24}	2.12×10^{-30}	3.60×10^{-41}	7.38×10^{-26}	8.98×10^{-25}	2.9×10^{-25}
Total		7.76×10^{4}	6.78×10^{3}	7.07×10^{-3}	2.87×10^{-3}	3.91×10^{3}	4.76×10^{4}	1.9×10^{-2}

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 11.2-3

ESTIMATED WASTE GAS RELEASE WITH RECOMBINER OPERATING

Based on gaseous activity from:

a. Waste gas cycle: 300 days of feed/20 days of decay/10 days of bleed.
b. Two units, 2546 MWt each.
c. 1% failed fuel.
d. 17-gpm total letdown flow rate to gas stripper from both units.
e. 100% of gases and 0.1% of iodines removed in gas stripper.
f. X/Q - 7.5×10^{-6} sec/ m^3 for calculating dose at site boundary.

Nuclide	Equilibrium Coolant Activity ($\mu Ci/cm^3$)	Curies In Tank At End Of Feed Cycle	Curies In Tank After 20 Days Decay	Discharge Rate (Ci/sec) Initial	Discharge Rate (Ci/sec) Final	Curies Discharged In One Cycle	Total Curies Discharged Per Year	Dose At Site Boundary (rem/yr)
Kr-85m	1.22	3.63×10^{1}	2.05×10^{-35}	2.14×10^{-4}	1.61×10^{-59}	4.44×10^{-37}	4.44×10^{-37}	5.3×10^{-43}
Kr-85	3.25×10^{-1}	1.63×10^{4}	1.63×10^{4}	1.70×10^{-3}	1.69×10^{-2}	1.46×10^{4}	1.46×10^{4}	5.8×10^{-3}
Kr-87	8.27×10^{-1}	7.96	0	0	0	0	0	0
Kr-88	2.36	4.92×10^{1}	0	0	0	0	0	0
Xe-131m	4.62×10^{-2}	1.95×10^{2}	6.16×10^{1}	6.43×10^{-5}	3.61×10^{-5}	4.22×10^{1}	4.22×10^{1}	1.3×10^{-5}
Xe-133m	1.33	5.42×10^{2}	1.30	1.36×10^{-6}	6.67×10^{-8}	3.71×10^{-1}	3.71×10^{-1}	1.5×10^{-7}
Xe-133	80.9	7.68×10^{4}	5.58×10^{3}	5.82×10^{-3}	1.57×10^{-3}	2.80×10^{-3}	2.80×10^{3}	1.1×10^{-3}
Xe-135m	7.13×10^{-1}	1.40	5.75×10^{-25}	6.00×10^{-31}	1.02×10^{-41}	2.09×10^{-26}	2.09×10^{-26}	2.5×10^{-32}
Xe-135	3.39	2.32×10^{2}	8.52×10^{-14}	2.98×10^{-20}	3.30×10^{-28}	1.40×10^{-15}	1.40×10^{-15}	1.7×10^{-21}
Xe-138	4.50×10^{-1}	9.59×10^{-1}	0	0	0	0	0	0
1-131	1.72	2.48×10^{-1}	4.44×10^{-1}	4.64×10^{-8}	1.96×10^{-8}	2.69×10^{-2}	2.69×10^{-2}	1.0×10^{-4}
1-132	5.85×10^{-1}	1.00×10^{-3}	0	0	0	0	0	0
1-133	2.65	4.23×10^{-2}	5.50×10^{-9}	5.79×10^{-15}	2.10×10^{-18}	6.31×10^{-10}	6.31×10^{-10}	6.6×10^{-13}
1-134	3.61×10^{-1}	2.35×10^{-4}	0	0	0	0	0	0
1-135	1.40	7.07×10^{-3}	2.05×10^{-24}	2.14×10^{-30}	3.63×10^{-41}	7.44×10^{-26}	7.44×10^{-26}	2.4×10^{-29}
Total		9.41×10^{4}	2.19×10^{4}	2.28×10^{-2}	1.85×10^{-2}	1.75×10^{4}	1.75×10^{4}	7.0×10^{-3}

Table 11.2-4
LIQUID WASTE DISPOSAL SYSTEM

	Shim Bleed		Equipment Drains	Clean and Dirty Wastes	Steam Generator Blowdown		Detergent Wastes
Sources	Reactor coolant letdown		Primary drain tanks	Waste drain tanks			Laundry wastes
Flow rate, gpd	2500		1150	10,150	90,600		1250
Activity, FPCA	1.0		1.0	0.36			
Collection tank volume, gal	120,000		120,000	5804			1230
Collection rate, gpd[a]	7,300[b]		7,300[b]	20,300			2500
Collection time days	13.2		13.2	0.23	0		0.39
Processing rate, gpd	31,700		31,700	34,560			72,000
Processing time, days	3.03		3.03	0.14	0		0.01
Discharge tank volume, gal	30,000		30,000	3548			1, 230
Discharge rate, gpd	7, 300		7, 300	72,000			72,000
Discharge time, days	3.28		3.28	0.04	0		0.01
Fraction of processed steam released	1.0		1.0	1.0	1.0		1.0
	Anion Ion Exch.	Evap.	Same as shim bleed	Mixed-Bed Demin	Mixed-Bed Demin. Case 1	Case 2	
DFs					Not	10^2(10)	None
I	10^2	10^2		10^2(10)	treated	10 (10)	
Cs, Rb	1	10^3		2 (10)		10^2	
Others	1	10^3		10^2 (10)		(10)	
Regenerant time, days	Not regenerated		Not regenerated	Not regenerated	Not regenerated		NA
Source terms	See Tables 11A-9 and 11A-10		See Tables 11A-9 and 11A-10	See Tables 11A-9 and 11A-10	See Tables 11A-9 and 11A-10		See Tables 11A-9 and 11A-10

a. Reflects shared system.

b. Sum of equipment drains and shim bleed for both units.

Figure 11.2-1
LIQUID WASTE DISPOSAL SYSTEM; PROCESS FLOW DIAGRAM, SHEET 1

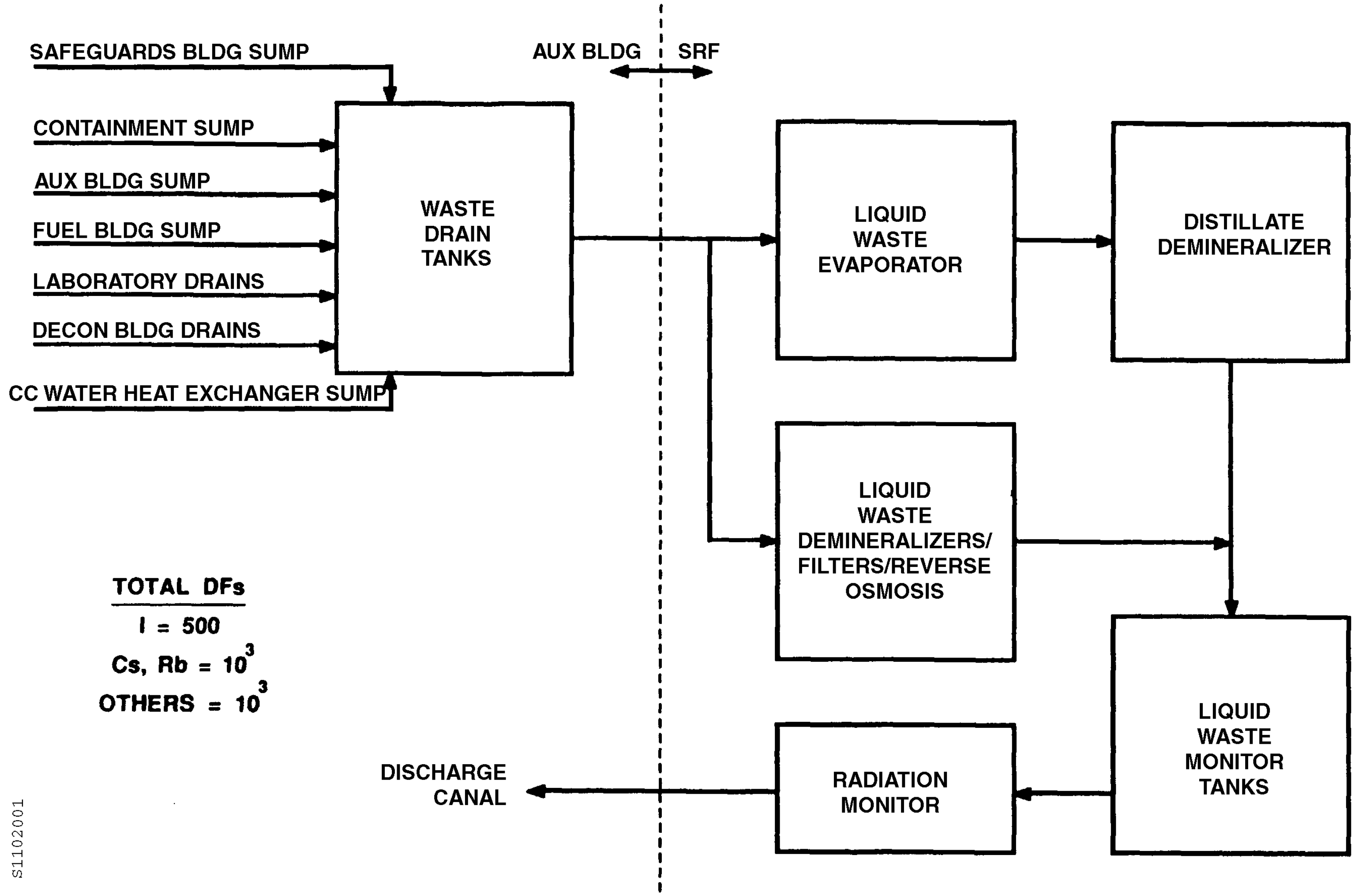


Figure 11.2-2
LIQUID WASTE DISPOSAL SYSTEM; PROCESS FLOW DIAGRAM, SHEET 2

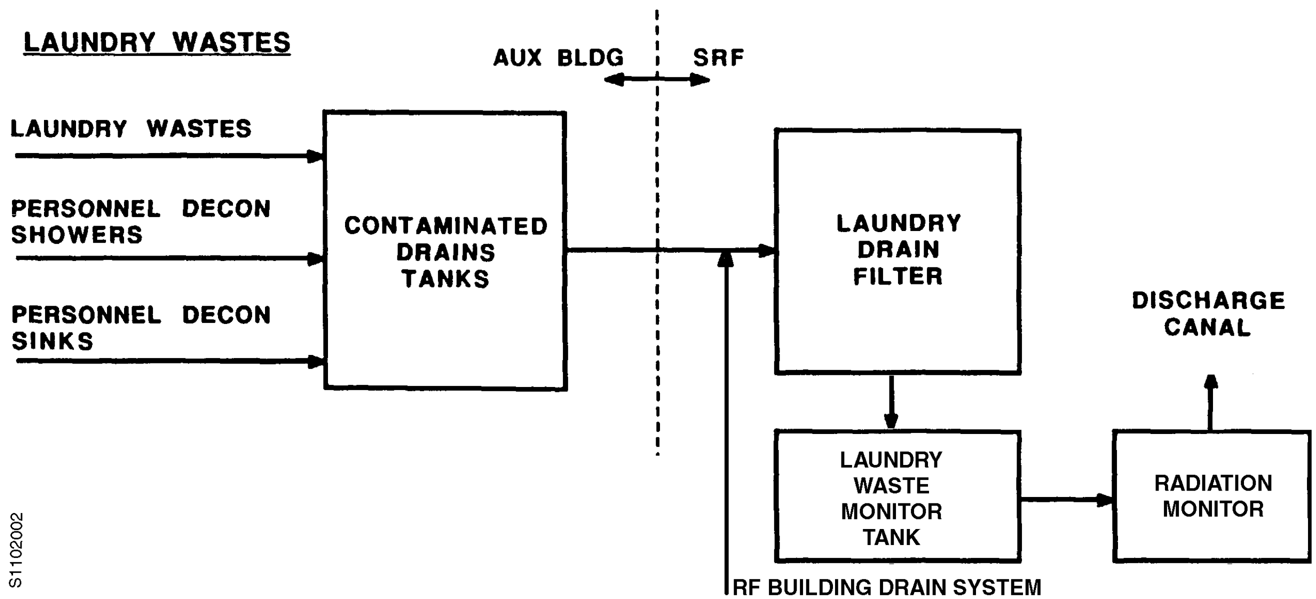


Figure 11.2-3
LIQUID WASTE SYSTEM PROCESS FLOW DIAGRAM

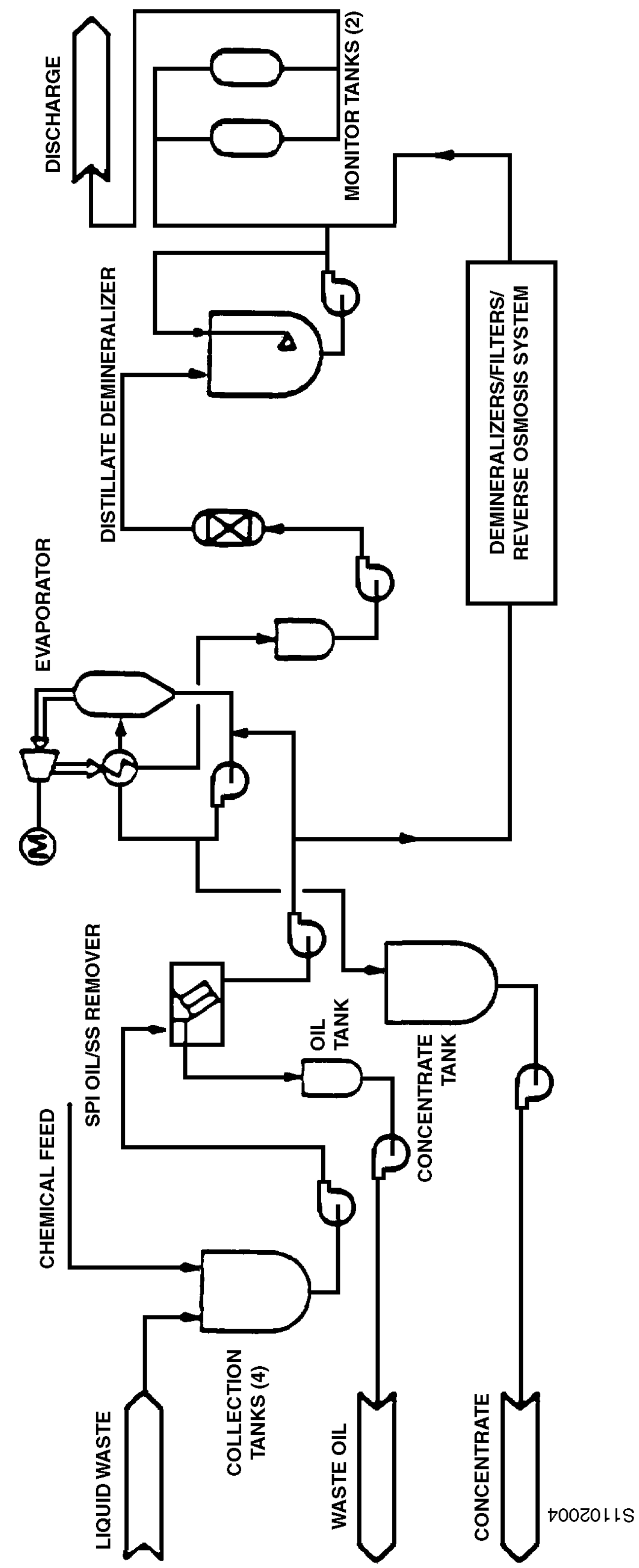


Figure 11.2-4
LAUNDRY WASTE SYSTEM PROCESS FLOW DIAGRAM

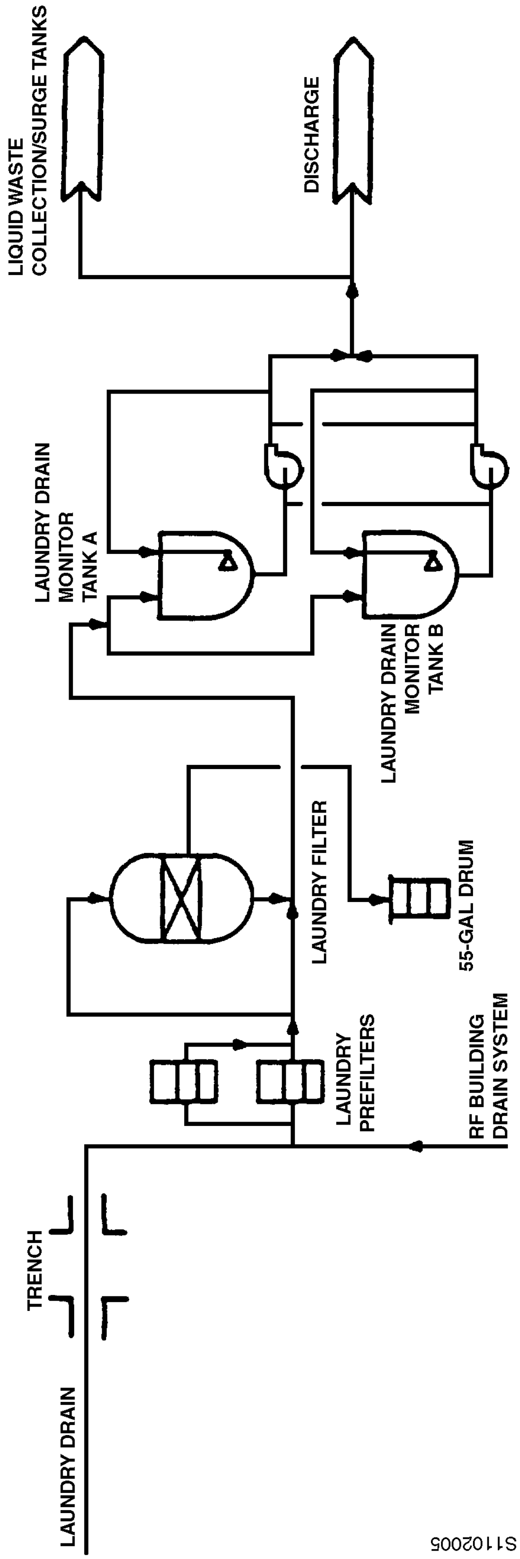
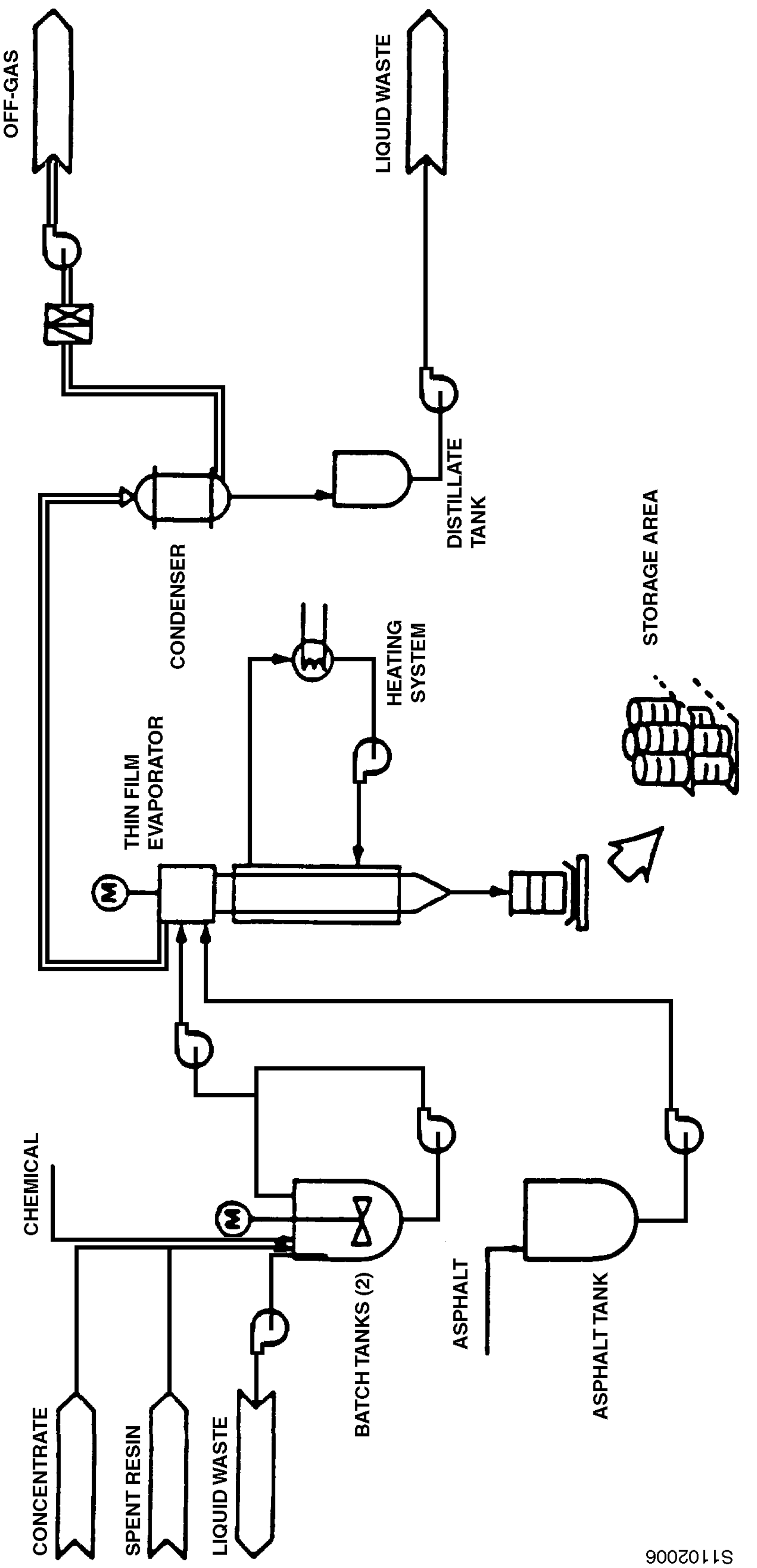


Figure 11.2-5
BITUMEN SOLIDIFICATION SYSTEM PROCESS FLOW DIAGRAM



11.3 RADIATION PROTECTION

11.3.1 Design Bases

Radiation protection, including radiation shielding, was designed to ensure that the criteria specified in 10 CFR 20[1] are met during normal operation and that the guidelines in 10 CFR 50.67 are met in the event of the design-basis loss of coolant accident (Section 14.5.5). Maximum dose limits for design-basis accident conditions are given in Table 14.5-11.

Allowable dose rates are based on the expected frequency and duration of occupancy. Occupancy time and dose rates are such that no personnel shall receive in excess of those doses recommended in 10 CFR 20. All dose rate calculations are based on 1% failed fuel elements. Allowable dose rates for typical locations are given in Table 11.3-1.

11.3.1.1 **Leak Reduction Program**

A leak reduction program has been established to minimize leakage from systems outside containment that would or could contain highly radioactive fluids during transients or accidents. The following systems, which are described in detail elsewhere in the FSAR, are at least partially located outside containment and are expected to contain potentially radioactive fluids immediately following an accident:

1. Safety injection system.
2. Containment and recirculation spray systems.
3. CVCS (those portions associated with safety injection).
4. Boron recovery system.
5. Resin waste disposal system.
6. Sampling system.
7. Containment vacuum system.
8. Containment purge system.

Several plant systems have been excluded from the leak reduction program. Their exclusion is justified because their unavailability would not eliminate any of the options for cooling the reactor core, nor would it prevent the use of any safety system. The excluded systems are the following:

1. CVCS (those portions not associated with safety injection).
2. Purification system.

---

1. Virginia Power implemented the revised 10 CFR 20 on January 1, 1994. However, as allowed by the NRC, the calculational methodology used for the design analyses is based on the revision of 10 CFR 20 to which the plant was originally licensed.

3. Gas stripper system.
4. Vent and drain systems.
5. Liquid waste disposal system.
6. Reactor cavity purification system.
7. Spent-fuel pool cooling and purification systems.

The letdown portion of the CVCS is normally used for reactor coolant system inventory control, reactor coolant pump seal injection, and reactor coolant system purification. After an accident, the safety injection system using the refueling water storage tank or containment sump would provide the necessary inventory control and seal injection functions. Coolant purification would be deferred until some time after the accident and would probably be performed using a temporary system. Since CVCS letdown will not be used after an accident, the gas stripper system and the vent and drain systems are not needed to support the associated vent. The containment sump would be used for liquid waste storage in place of the liquid waste storage system. The reactor cavity purification system is used during refueling outages. The spent-fuel pool cooling and purification system is not connected to the reactor coolant system or to containment.

A preventive maintenance program, including periodic leak tests, has been established for the systems in the leak reduction program. This program uses administrative controls and procedures as outlined by the plant quality assurance program.

11.3.2 Shielding Design and Evaluation

11.3.2.1 **Primary Shielding**

Primary shielding is provided to limit radiation emanating from the reactor vessel. The radiation consists of neutrons diffusing from the core, prompt fission gammas, fission product gammas, and gammas resulting from the slowing down and capture of neutrons.

The primary shielding is designed to:

1. Attenuate neutron flux to prevent excessive activation of unit components and structures.
2. Reduce the contribution of radiation from the reactor to obtain a reasonable division of the shielding function between primary and secondary shields.
3. Reduce residual radiation from the core to a level that does not limit access to the region between the primary and secondary shields at a reasonable time after shutdown.
4. Postaccident shielding considerations are discussed in Section 11.3.2.9.

The primary shield consists of a water-filled neutron shield tank with a radial dimension of approximately 3 feet, surrounded by 4.5 feet of reinforced concrete. The neutron shield tank is designed to prevent overheating and dehydration of the concrete primary shield wall and to prevent activation of the plant components within the reactor containment. A thermosiphon cooling system is provided for cooling the water in the shield tank.

A 2-inch-thick cylindrical lead shield that is approximately 15-foot-high is located beneath the neutron shield tank to protect station personnel servicing the neutron detectors during reactor shutdown.

A 3-1/2-inch thick stainless steel radiation shield is provided at the 12-inch diameter incore sump room drain to protect station personnel during normal power operation and refueling outage. The drain is designed to convey the held up water, in excess of the invert elevation of the Incore Sump Room drain, from the Incore Sump Room to the containment sump strainer. This additional water facilitates submergence of the containment sump strainer for RS and LHSI pumps for post-LOCA operation.

lncore instrumentation guide tube shielding is provided in the form of a vertical wall and horizontal table installed in the lncore Sump Room. Each shield consists of 1-1/2-inches of lead wrapped in coated carbon steel. The shielding protects personnel during refueling outages.

To maintain the integrity of the primary shield, streaming shields fabricated from both masonite Benelex 70 and steel are provided in the annular gap between reactor vessel flange and the primary shield concrete. In addition, masonite Benelex 401 and steel streaming shields located outside the primary concrete shield are provided around all of the reactor coolant pipe penetrations.

The primary shield arrangement is shown in Figures 11.3-1 and 11.3-2. The shield materials and thicknesses are listed in Table 11.3-2.

11.3.2.2 Secondary Shielding

Secondary shielding consists of reactor coolant loop shielding, reactor containment shielding, fuel handling shielding, auxiliary equipment shielding, and waste storage shielding.

Nitrogen-16 is the major source of radioactivity in the reactor coolant during normal operation and establishes the combined thickness of the crane and containment walls. Activated corrosion and fission products in the reactor coolant system establish the shutdown radiation levels in the reactor coolant loop areas. Tables 9.1-4 and 11.3-3 list the activities that were used in designing the containment secondary shielding. Table 9.1-4 lists the fission product activities in the reactor coolant system with 1% failed fuel. Table 11.3-3 lists the activated corrosion product activities and the N-16 activity at the reactor vessel outlet nozzle.

Activated corrosion and fission products from the reactor coolant system are the radioactive sources for which shielding is required in the auxiliary and waste disposal systems.

Auxiliary steam used for space heating and other purposes throughout the station may become contaminated due to primary-to-secondary leakage. The estimated dose rate at the surface of a 6-inch, 15-psig auxiliary steam supply header is 2×10^{-6} mrem/hr. The estimated dose rate at 3 feet is 1.25×10^{-7} mrem/hr. The dose rate estimates are based on 1% failed fuel activities (Table 9.1-4), 25% steam flow, 1000 cm^3/hr total steam generator leakage, and zero decay time. All noble gases and 1% of the halogens are assumed to leak into the steam generator. Based on these assumptions, the dose received by an individual in the vicinity of the auxiliary steam piping is insignificant.

11.3.2.3 **Reactor Coolant Loop Shielding**

Interior shield walls separate reactor coolant loop, pressurizer, incore instrumentation, and containment access sectors. This shielding allows access to the incore instrument sector during normal operation and facilitates maintenance in all sectors during shutdown. The crane support wall provides limited access protection in the annulus between the crane wall and the reactor containment wall and provides part of the exterior shielding required during power operation. Shield walls are provided around each steam generator above the charging floor to a height required for personnel protection. The shielding arrangement is shown in Figures 11.3-1 and 11.3-2. The shield materials and thicknesses are listed in Table 11.3-2.

11.3.2.4 **Reactor Containment Shielding**

The containment shielding consists of the steel-lined, steel-reinforced concrete cylinder and hemispherical dome, as further described in Chapter 5. This shielding, together with the crane support wall, attenuates radiation during full-power operation at the outside surface of the containment to less than 0.75 mrem/hr. In addition, it attenuates the dose rate from the design-basis accident to design levels.

11.3.2.5 **Fuel Handling Shielding**

Fuel handling shielding is designed to facilitate the removal and transfer of spent fuel assemblies from the reactor vessel to the spent-fuel pool. It is designed to protect personnel against the radiation emitted from the spent fuel and control rod assemblies.

The refueling cavity above the reactor vessel is flooded to Elevation +45-1/3 ft. to provide a temporary water shield above the components being withdrawn from the reactor vessel. The water height is thus approximately 27 feet above the reactor vessel flange. This height ensures that more than 84 inches of water is present above a withdrawn fuel assembly at its highest point of travel. Under these conditions, the dose rate is less than 50 mrem/hr at the water surface.

The fuel is removed from the reactor vessel to the spent-fuel pool by the fuel transfer mechanism via the refueling canal.

The spent-fuel pool in the fuel storage building is permanently flooded to provide more than 84 inches of water above a fuel assembly when it is being withdrawn from the fuel assembly transfer basket. Water height above stored fuel assemblies is at least 24 feet. The sides of the spent-fuel pool, three of which also form part of the fuel storage building exterior walls, are 6-foot-thick concrete to ensure a dose rate of no more than 2.5 mrem/hr outside the building.

Sixteen feet of earth shielding is provided above the fuel transfer tube between the reactor containment and the fuel storage pool wall.

11.3.2.6 **Auxiliary Equipment Shielding**

The auxiliary components exhibit varying degrees of radioactive contamination due to the handling of various fluids. The function of the auxiliary shielding is to protect personnel working near the various auxiliary system components, such as those in the CVCS, the boron recovery system, the waste disposal system, and the sampling system. Controlled access to the auxiliary building is allowed during reactor operation. Each equipment compartment is individually shielded so that compartments may be entered without having to shut down and, possibly, decontaminate the entire system. Ilmenite concrete is used in certain areas where substantial shielding is required and space is at a premium, such as the primary drain tank compartment and the mixed-bed demineralizer compartments.

Ion exchangers and the most highly contaminated filters are located in the ion-exchange structure along the north wall of the auxiliary building. Each ion exchanger or filter is enclosed in a separate, shielded compartment. The concrete thicknesses provided around the shielded compartments are sufficient to reduce the surrounding area dose rate to less than 2.5 mrem/hr, and the dose rate of any adjacent cubicle to less than 100 mrem/hr. The shielding thicknesses around the mixed-bed demineralizers are based on a saturation activity that gives a contact radiation level of nearly 11,000 rem/hr.

Ion exchangers and potentially contaminated filters are also associated with the steam generator blowdown treatment system (no longer used) located in the condensate polisher building.

In many areas, tornado missile protection in the form of thick concrete affords more shielding than that required for radiation protection.

11.3.2.7 **Waste Storage Shielding**

The waste storage and processing facilities in the auxiliary building and decontamination building, the RF, and the waste storage tanks are shielded to provide protection of operating personnel in accordance with the radiation protection design bases set forth in Section 11.3.1.

Periodic surveys by health physics personnel using portable radiation detectors ensure that radiation levels outside the shield walls meet design specifications, and establish access limitations within the shielded cubicles. In addition, continuous surveillance is provided at the Radwaste Facility drumming area and control area and the RF compactor area by area radiation monitors (Section 11.3.4).

Area and process monitoring also ensure that any accidental radioactivity release would be detected within a reasonable period of time. The largest accidental radioactivity release from the waste disposal system would be the rupture of one of the waste gas decay tanks. An analysis of this accident is provided in Section 14.4.2. Furthermore, periodic samples of the gas in the waste gas decay tanks are analyzed by health physics personnel to ensure that the activity level in these tanks is never above the design level used in the accident analysis.

11.3.2.8 **Accident Shielding**

Accident shielding is provided by the reactor containment, which is a reinforced concrete structure lined with steel. For structural reasons, the thicknesses of the cylindrical walls and dome are 54 and 30 inches, respectively. These thicknesses are more than adequate to meet the requirements of 10 CFR 100 at the exclusion boundary.

Additional shielding is provided for the control room. This, together with the shielding afforded by its physical separation from the containment structure, ensures that an operator would be able to remain in the control room for 30 days after an accident and not receive an integrated whole-body dose in excess of 5 rem. The calculational methods and radiation sources used in designing the control room shielding are discussed in Section 11.3.6.

In addition, the control room will serve as a fallout shelter with a protection factor of better than 500, as defined by the Office of Civil Defense.

11.3.2.9 **Postaccident Shielding Review**

A postaccident shielding review was conducted during the 1979 to 1980 time period using the Stone & Webster GAMTRAN1 computer code with inputs developed from the ACTIVITY-2 and RADIOISOTOPE computer codes. NRC-specified source terms were used. The review assumed that the postaccident period was divided into two phases: the mitigation phase and the recovery phase.

The mitigation phase, which was assumed to last 6 months, experiences radiation levels resulting from the operation of the recirculation portion of the safety injection and recirculation spray systems and the postaccident sampling system. This phase also experiences radiation levels from the auxiliary building sump and from the drain lines from the discharge of the auxiliary building and safeguard building sump pumps to the low-level liquid waste tank, as well as to the containment.

The recovery phase has been identified as the period beginning 6 months after the accident, when cleanup and plant recovery is performed. The recovery phase is a controlled evolution that will be planned and carried out to meet the specific recovery requirements of the particular accident.

All essential system piping and equipment that are required to mitigate the effects of a loss-of-coolant accident (LOCA), and that contain or could contain highly radioactive fluids, were considered as sources in the shielding review. These systems included the high-head safety injection system, the low-head safety injection system, the recirculation spray system, the sample system, and the containment atmosphere cleanup (hydrogen recombiner) system. In addition, other systems that are not required to mitigate a LOCA, but that could contain significant radioactivity, were considered, such as drain lines and standing water in sumps and waste tanks. All branch connections to and from these systems were considered as sources to the first isolation valve. Other sources, such as the shine from the containment dome, shine through containment penetrations, and shine through the personnel hatch, were considered. The location of field run pipe, which is part of the systems listed above, was considered in this analysis. The routing and location of radioactive piping is such that the piping is in shielded areas. The exact routing of field run pipe is not critical in the production of radiation zone maps. The highest activity level in each zone is calculated, and that level is considered for the entire zone. For instance, the highest activity may be 12 inches from a pipe, regardless of its exact location within the zone.

Indirect radiation was not considered as a source. Buildup factors in shield walls are considered, but scatter over walls or through labyrinth doorways was not considered. Airborne activity was not considered as a source in the shielding review.

All vital areas were also considered during the review. Vital areas for personnel exposure are defined as those areas that require continuous or frequent occupancy in order to control, monitor, and evaluate the accident. These areas include the control room, technical support center, the counting lab/health physics area, the operational support center, and the security control center. In addition, any area to which access is required to perform manual operation of equipment in systems that are used to mitigate the accident was considered. Vital areas for equipment qualification include all areas in which mitigating equipment is located. Nonvital areas include the entire auxiliary building, main steam valve house, quench spray pump house, safeguards building, service building, and selected areas in the yard.

11.3.2.9.1 Mitigation Phase

The integrated radiation dose calculated for this phase is comprised of the original license period of 40-year normal dose and a 6-month mitigation phase dose. The safety equipment required to operate during the mitigation phase is the same as that equipment tabulated in Chapter 7 for NRC I&E Bulletin 79-01 (Reference 1). The source term developed to calculate the 40-year normal operating dose is based on the assumptions in Chapter 11. The source terms assumed to calculate the 6-month mitigation phase dose are based on TID-14844 (Reference 2) and Regulatory Guide 1.4 (Reference 3), and are listed in Table 11.3-4. The impact of increased integrated dose associated with an additional 40 years of normal operation is small and is accounted for in the environmental qualification of equipment applied to the mitigation phase.

The exact course of an accident is unpredictable. It is impractical to determine the dose rate and shielding requirements for every possible location and time duration associated with each possible failure, or incident, that requires personnel access. Therefore, radiation “zone maps” have been developed for use as postaccident administrative guidelines. These maps show estimated worst-case gamma rates in various areas of the plant as a function of time. The zone maps are used to help plant operators plan access and egress routes, and to help evaluate the relative benefits of delaying certain actions to allow for radioactive decay. The gamma dose rates on the zone maps are based on worst-case source terms, but do not consider an airborne source term. Depending on the severity of the situation, actual dose rates may be smaller. The zone maps are used only as guidelines, and actual radiation levels will be determined through actual postaccident surveys. In addition, the dose rates on the zone maps are based on the highest, or one of the highest, dose rates in that area. The dose rates at other locations within that area may be lower.

11.3.2.9.2 Recovery Phase

The design basis for certain systems and their associated shielding did not consider postaccident recovery operations, that is, postaccident cleanup of highly radioactive fluids. These are the waste disposal system, the boron recovery system, the containment purge system, and the letdown and charging portions of the CVCS. As a result, these systems will not be used for postaccident cleanup operations.

The activity levels (based on Regulatory Guide 1.4 and TID-14844) of the influent to the liquid waste disposal system or to the boron recovery system are approximately 2×10^3 μCi/cm^3 after 6 months of radioactive decay. The area radiation dose rates from concentrated waste and from waste storage tanks would severely limit access to parts of the auxiliary building and would hinder the operation of both units. Since the radioactive waste disposal systems are common to both Units 1 and 2, the use of these systems for the cleanup of waste in the accident-affected unit would preclude the normal use of the radioactive systems for the non-accident-affected unit.

There is extensive piping for the above-listed systems throughout the auxiliary building. The resulting dose rate if all these systems operated simultaneously would severely limit freedom of access for required operations. Shielding for the piping and components would be very difficult, and in some cases impossible, to install, because of the physical arrangement of the piping and components.

11.3.2.9.3 Postaccident Sampling Capability

The Surry Power Station has the capability to sample the reactor coolant, containment sump, and the containment atmosphere. The reactor coolant sample can be taken and analyzed within approximately 3 hours of the decision to sample. A containment atmosphere sample can also be taken with the high radiation sample system. Provisions are included for personnel exposure control. A detailed discussion of the postaccident sampling system is contained in Chapter 9.

11.3.2.10 **Steam Generator Storage Facility**

The Steam Generator Storage Facility is a reinforced concrete structure located within the station but outside the protected area. Major components housed in the facility include the original Steam Generator lower assemblies and the original Reactor Vessel Closure Heads. The facility has no interface with any permanent plant structures and is a restricted area. It is included in the Radiological Survey Program.

The radionuclide inventory of a steam generator as it is removed from the containment has been estimated about 1400 curies. This will decay to about 2-20 curies in 30 years and 0.0027 to 0.027 curies in 80 years. At the end of station life, it can be conservatively assumed that the total inventory of 12-120 curies of Cobalt-60 for the 6 steam generators will represent less than 0.1% of the total activity on site, exclusive of fuel and control rods. The lower shells could be handled easily as part of station decommissioning activities.

The facility is an above ground concrete structure on a poured structural slab. The exterior walls are as thick as necessary to meet the 40 CFR 190 requirement of 25 millirem/year. The facility is designed as an 80 year structure. It is not necessary that the facility be a seismic category I structure. The facility is designed with a dose rate criteria of radiation Zone I for the contact dose.

The original steam generator lower shells are tracked for decay and the radiation safeguards of the storage building is maintained. The exterior walls of the facility are periodically measured for low-level radiation dose.

The Steam Generator Storage Facility sump is periodically pumped out and taken to the Laundry Drain System for processing if contaminated. Table 11.3-6 list the Laundry Facility Continuous Effluent Particulate and Iodine.

11.3.3 Process Radiation Monitoring System

The process radiation monitoring system continuously monitors selected lines containing, or possibly containing, radioactive effluents. Lines through which waste liquids and gases are discharged to the environment are also monitored. The function of this monitoring system is to warn personnel of increasing radiation levels that could result in a radiation health hazard and to give early warning of a system malfunction. An audible alarm in the control room has been incorporated to indicate the loss of power to the monitor cabinet. The process radiation monitoring system serving both units is comprised of the channels listed in Table 11.3-5.

Each radiation monitoring channel is designed to provide continuous information about the process or effluent stream being monitored. Continuous, as used to describe the operation of the process and effluent radiation monitoring systems, means that a monitor provides the required information at all times with the following exceptions: (1) the system is not required to be in operation because of specified plant conditions per the Technical Specifications, or (2) the system is out of service for testing or maintenance and approved alternate monitoring, sampling, or recording methods are in place.

With the exception of the monitoring channels from the Laundry and Radwaste Facilities, each channel has a readout in the control room, and selected channels, as indicated in Table 11.3-5, have a readout at the detector location. The Laundry Facility monitors all readout locally and the Radwaste Facility monitors readout in the Radwaste Facility control room as well as locally. In addition, each channel has an audible and visual alarm for radiation levels in excess of preset values, as well as a visual alarm for detector malfunction. The output from all channels is recorded on recorders that produce a continuous record of radiation levels and radioactive discharges from the station. Each channel has its own power supply and check source thus making it completely independent of any other channel. Each channel check source is remotely operated from the main control room except the process monitors in the Radwaste Facility, the Laundry Facility, and the High-Range Effluent monitors. The normal/high range Process Vent and Vent Stack No. 2 (MGPI) effluent monitors do not have a check source. The High-Range Effluent monitors for the main steam line and the exhaust of the turbine AFW pump have a built-in radioactive source that provides a life-zero signal for testing purposes. The Radwaste Facility and the Laundry Facility check sources are remotely operated from local control panels. The MGPI equipment is continually self-checking that, should the detector output signal drop below some prescribed value, effectively indicating that there is no background signal, the detector will be considered faulty. This monitoring, in conjunction with continual testing of the electronic signal processing circuits by generation and confirmed receipt of test signals, provides assurance that the circuits remain in good health. The adjustment of alarm setpoints, voltage, power, and other variables is made from the control room for all radiation monitors except for the following: 1) monitors in the Radwaste, and 2) monitors in the Laundry Facilities. Adjustments to the Radwaste and Laundry Facility monitors are performed locally. The normal/high range Process Vent and Vent Stack No. 2 MGPI effluent monitors can be adjusted either at the local display unit (LDU) or at the remote display unit (RDU). The High-Range Effluent monitors can be adjusted at the local processing and display unit (LPDU). The entire system is designed with emphasis on system reliability and availability. Certain channels, as indicated in the following text, actuate control valves on a high-activity alarm signal. In the event of a loss of power to these detectors, the system is designed to provide an alarm of the failed condition. Any control functions associated with a high radiation alarm are also initiated.

The expected concentrations of radionuclides in the process streams monitored by the ventilation vent monitors, component cooling water monitors, component cooling heat exchanger service water monitors, condenser air ejector monitors, steam generator blowdown monitors, and recirculation spray cooler heat exchanger service water monitors are natural background radioactivity. The sensitivity of these detectors ensures that abnormal plant conditions will be detected before they cause a hazard to the operators or to the general public.

The use of a single detector is justified in lines used for normal releases from the plant. The surveillance requirements for each of the liquid effluent monitors and gaseous effluent monitors are given in the Offsite Dose Calculation Manual. The liquid and gas waste tanks are sampled and analyzed before and during discharges. Effluent source terms are discussed in Appendix 11A.

Channels monitoring Unit 1 are supplied from the emergency bus for Unit 1. Channels monitoring Unit 2 are supplied from the emergency bus for Unit 2. Channels monitoring systems or areas common to both units can be supplied from the emergency bus for either Unit 1 or Unit 2.

The type of detector, sensitivity, range, background radiation, and other information for each channel are listed in Table 11.3-5. Counting rates are given in Table 11.3-6. A description of each channel is included in the following text.

11.3.3.1 **Process Vent Particulate Monitor**

This channel continuously withdraws a sample from the process vent and passes the sample through a moving filter paper with a collection efficiency of 99% for particle sizes greater than 1.0μ. The amount of deposited activity is continuously scanned by a silicon diode type. A high-activity alarm automatically initiates the closure of the process vent discharge line valves.

A separate isokinetic sampling nozzle used for Health Physics accountability is provided for each unit, as shown in Reference Drawing 2. The nozzles sample the process vent fluid to ensure that a representative sample is taken. Isokinetic sampling is achieved by locating the nozzles in a straight unobstructed piping run of at least five pipe diameters (30 inches). The sampling systems include a pump and a mass flow meter, and supply 1-cfm flow to a sample filter.

11.3.3.2 **Process Vent Gas Monitor**

This channel takes the continuous process vent sample, after it has passed through the particulate filter paper, and draws it through a sealed system to the process vent gas monitor assembly, which is a fixed lead-shielded sampler containing a silicon diode type detector. The sample activity is measured, and is then returned to the process vent. A high-activity alarm automatically initiates the closure of the process vent discharge line valves. A purge system is integral with the gas monitoring system for flushing the sampler with clean air for purposes of calibration.

11.3.3.3 **Ventilation Vent No. 1 Gas Monitor**

This channel withdraws a sample from ventilation vent no. 1 and passes the sample through a particulate and iodine filter assembly. The sample then enters a gas monitor assembly, which is a fixed lead-shielded sampler enclosing a beta scintillation detector. The sample activity is measured, and is then returned to the ventilation vent. A purge system is integral with the gas monitoring system for flushing the sampler with clean air for purposes of calibration. A multi-probe isokinetic sampling nozzle is provided to obtain a representative sample in the duct.

11.3.3.4 **RF Vent Particulate and Gas Monitors**

These two channels continuously sample the RF ventilation stack particulate and gas. The monitors process a sample (approximately 2 scfm) through a replacable fixed 0.3-micron filter. Noble gases are then monitored in a pressure compensated chamber. Sample flows are supplied by an isokinetic probe. This monitor has provisions for a removable silver zeolite iodine sampler cartridge and for a grab sample for tritium analysis.

11.3.3.5 **Component Cooling Water Monitors**

These two channels continuously monitor the component cooling water by means of a gamma scintillation detector enclosed in lead shielding and mounted on the component cooling piping. The complex piping arrangement of this system dictates that two detectors are required to ensure that the system is properly monitored. Activity is indicative of a leak into the component cooling system (Section 9.4) from one of the radioactive systems that exchange heat to the component cooling system.

11.3.3.6 **Component Cooling Heat Exchanger Service Water Monitor**

These four channels continuously monitor the service water effluent from the four component cooling water heat exchangers. Each channel consists of an inline gamma scintillation detector located in a pipe well on the discharge side of the heat exchanger.

11.3.3.7 **Liquid Waste Disposal System Monitor**

The RF has a liquid waste discharge monitor. This channel continuously monitors processed liquid and laundry waste leaving the RF by means of a gamma scintillation detector mounted on a 3-inch discharge pipe. The unit is shielded to ensure the required detector sensitivity. A high-activity alarm automatically initiates closure of a valve that terminates discharges from the RF.

11.3.3.8 **Condenser Air Ejector Monitors**

There are two identical radiation detection channels (1-SV-RM-111 and 2-SV-RM-211 for Units 1 and 2, respectively) for continuously monitoring the normal gaseous effluent from the condenser air ejectors to the atmosphere. The detectors are gamma scintilators mounted in an in-line sampler surrounded by lead shielding. Activity is indicative of a primary-to-secondary system leak. On a high-activity alarm, the flow is automatically diverted to the containment.

If a condition exists such that the normal radiation monitor alarms, but the containment is under Phase 1 isolation (Section 5.2.2), isolation valves 1-SV-TV-102, 102A, and 103 (Unit 1) and 2-SV-TV-202, 202A, and 203 (Unit 2) would shut (Reference Drawing 1) to stop all flow from the air ejector. However, the operator can maintain condenser vacuum by manually establishing air ejector flow through a discharge line to a point upstream of the ventilation vent no. 2 high-range noble gas effluent radiation monitor (Section 11.3.3.14). This monitor provides both normal and high-range effluent radiation detection. If ultimately required, the air ejector effluent can be isolated remotely from the control room.

11.3.3.9 **Steam Generator Blowdown Sample Monitors**

Each of these channels (two channels per unit) monitors the liquid phase of the steam generators for radioactivity indicative of a primary-to-secondary system leak. The three steam generator blowdowns are combined and continuously monitored by the detectors. Upon indication of radioactivity, a valving arrangement enables the steam generators to be individually sampled, in turn, to determine the source of the activity. Once it has been established which steam generator is leaking, one of the detectors monitors only the blowdown from that steam generator, while the other detector monitors the combined blowdown from the other two steam generators. The detectors are gamma scintillation detectors, mounted in liquid samplers surrounded by lead shielding.

11.3.3.10 **Recirculation Spray Cooler Service Water Outlet Monitors**

The recirculation spray coolers, as part of the recirculation spray system (Section 6.3.1), operate only when containment pressure increases to the Hi Hi Consequence Limiting Safeguards (CLS) setpoint.

There are four recirculation spray coolers per unit, and each service water outlet line from the coolers is monitored, thus giving a total of eight channels. Each of these channels is identical. If the recirculation spray system is placed in service, a 5-gpm to 10-gpm sample is drawn out of each service water outlet line by a small pump with a 2-hp motor and passed through an offline liquid sampler, where it is monitored for activity indicative of a leak in the respective recirculation spray cooler. After passing through the liquid sampler, which is located outside the containment, the sample is returned to the service water line. Each monitor consists of a gamma scintillation detector mounted in a standard offline sampler surrounded by 3 inches of lead.

To ensure low background radiation in the event of an accident, the Unit 1 monitors are located in the Unit 2 safeguards building and the Unit 2 monitors are located in the Unit 1 safeguards building.

11.3.3.11 **Reactor Coolant Letdown Gross Activity Monitors**

Each of the units has its reactor coolant continuously monitored by means of a sample taken from the letdown line to the CVCS (Section 9.1). In this system, large variations in activity level are possible in the event of fuel assembly failure. This is a two-stage monitoring system consisting of a low-range channel and a high-range channel. There is one such system for each unit. After being withdrawn from the letdown line, the sample is passed through a delay line to allow N-16 to decay, then enters a sampler consisting of two gamma scintillation detectors surrounded by lead shielding, and is finally discharged to the volume control tank. Both detectors sit on a 1/2-inch removable stainless steel tube, providing flow through the sampler. Shielded lead plugs are used to convert the two detectors into either high- or low-range letdown monitors.

Normally, the low-range detector will be sitting on the 1/2-inch tubing and the high-range detector will be sitting on the shielded lead plug. In the event of a fuel element failure, the activity released could be sufficient to raise the coolant activity level above 1.0 $\mu Ci/cm^3$ gross fission products. This causes the high-range monitor to begin to indicate activity level at 10^{-1} $\mu Ci/cm^3$, providing a one-decade overlap. At this point, the high-range channel provides the activity data, and the low-range monitor can be converted into a high-range monitor by inserting a shielded lead plug.

11.3.3.12 **Circulating Water Discharge Tunnel Monitors**

Each of these identical channels (one per unit) monitors the effluent (service water, condenser circulating water, and liquid waste) in the circulating water discharge tunnel beyond the last point of possible radioactive material addition. A gamma scintillation detector slides into a capped pipe, which is then inserted directly into the discharge tunnel and acts as a well. At the top of the pipe is a waterproof support assembly that encloses a check source. The entire device is waterproof.

11.3.3.13 **Ventilation Vent No. 2 Particulate and Gas Monitors**

The two channels in Ventilation Stack No. 2 continuously sample for particulate and gas in the same way that the two Process Vent channels monitor the process vent sample, except that multi-probe samplers are provided to obtain a representative sample in the duct and both channels are equipped with silicon diode type detectors. In addition the post-accident noble gas and particulate monitor is used to obtain grab samples of the ventilation flow stream. Finally, the operability of the ventilation vent No. 2 particulate and gas monitors is relied upon in conjunction with the fuel pit bridge area monitor and communications to provide a timely and valid indication of a fuel handling accident in the spent fuel pool.

11.3.3.14 **High-Range Postaccident Radiation Monitors**

Methods for monitoring high-level releases of noble gases, iodine, and particulates have been developed and implemented. All potential releases are monitored by instrumenting ventilation vent no. 2, the process vent stack, main steam safety valve and power operated relief valve header, and the auxiliary feedwater pump turbine exhaust. The waste gas decay tank and hydrogen purge exhaust are discharged through the process vent stack. The auxiliary building, decontamination building, fuel building, and safeguards area exhausts are discharged through the auxiliary building ventilation vent no. 2. The containment purge system, which is common to both units, discharges through the ventilation vent no. 2 during outages. The main condenser air ejectors normally discharge to the atmosphere, but flow is diverted to containment if the set radiation level limit is exceeded.

The high-range noble gas radiation monitors on the ventilation and process vents are listed in Table 11.3-8. These monitors have a range of 10^{-7} to 10^{5} $\mu Ci/cm^3$ (Xe-133) under normal background conditions (less than 1 mR/hr). Due to shielding around the detector, the reduction of effluent detector sensitivity under maximum background conditions will not exceed the normal effluent instrument range. A multidetector system with detectors enclosed in lead shielding and sufficient range overlap is provided to ensure complete coverage for all expected background conditions. Shielded effluent detectors are needed to obtain the required sensitivities.

Accident particulate and iodine releases are determined by retrieving fixed filters for laboratory analysis. The filters are shielded to provide personnel protection during removal and reinstallation. Several filters in parallel provide for continuous sampling during filter removal.

High-range monitors, with a usable range of 0.01 mrem/hr to 10,000 R/hr, are installed on all main steam lines and the exhaust of the turbine driven AFW pump. These monitors are listed in Table 11.3-8. The 10,000 R/hr maximum reading corresponds to a noble gas concentration which is significantly greater than the maximum anticipated value, as determined by analysis, for noble gas concentrations following any design basis accident. The main steam monitors will be used in conjunction with secondary system sampling and offsite radiation monitoring.

The control units for the monitors contain the electronics necessary to interpret and display detector readings. Four control units, one for each monitor, are located in the Unit 1 Containment Spray Pump House and four control units are located in the Unit 2 Containment Spray Pump House. The units provide visual alarms for failure, alert, and high radiation. A digital readout of radiation level is also provided.

The detectors are powered from the control units, called LPDUs. The LPDUs are powered from reliable sources.

The Surry Power Station has the capability of monitoring all vital areas through the process vent and ventilation vent stack samples or local grab samples, as appropriate. Accurate monitoring of iodine in the presence of high noble gas concentrations is accomplished by the use of silver zeolite sampling cartridges. The cartridges can be analyzed by the multichannel analyzer system (MCA) that is located in a concrete walled count room for shielding purposes. The MCA detectors are located within lead-lined shields that also contribute to background reduction. This combination of shielding provided in the count room is adequate to provide a low background analysis location under most emergency conditions. If background becomes too high for accurate analysis, samples can be taken to the Radwaste Facility or shipped offsite. Procedures for iodine sampling and analysis are available in the Health Physics office.

Particulate sampling is accomplished in conjunction with radioiodine sampling by using fiber filter patches positioned upstream of the iodine filter. Particulate analysis is accomplished by using a multichannel analyzer.

11.3.3.15 **Storm Drain Radiation Sample System**

The storm drain radiation sample system is used to monitor for radioactive contamination of the effluent from the storm drain system prior to discharge into the James River. Recording flow meters and automatic wastewater samplers are installed at the four final release points of the storm drain system. Access to the equipment is through precast equipment manholes into the buried storm water drainage lines adjacent to the discharge canal. Electrical service to the equipment is provided by 120V ac power outlets in weatherproof enclosures inside the manholes. Samples are automatically drawn on a periodic basis to be sampled by Health Physics personnel for radioactive material content.

11.3.4 Area Radiation Monitoring System

11.3.4.1 General

The area radiation monitors are designed for continuous operation. Continuous, as used to describe the operation of an area radiation monitor, means that the monitor provides the required information at all times with the following exceptions: (1) the monitor is not required to be in operation because of specified plant conditions per the Technical Specifications, or (2) the system is out of service for testing or maintenance.

The area radiation monitoring system reads out and records the radiation levels in selected areas throughout the station and activates alarms (audible and visible) if these levels exceed a preset value or if the detector malfunctions. With the exception of the containment gas and particulate monitors, each detector reads out and activates alarms, both in the control room and at its station location. Each channel is equipped with a check source remotely operated from the control room. The recorders provide a continuous permanent record of radiation levels while the detectors are functioning. Detectors monitoring Unit 1 are supplied with power from the emergency bus for Unit 1. Detectors monitoring Unit 2 are supplied with power from the emergency bus for Unit 2. Detectors monitoring areas common to both units have the capability of being supplied with power from the emergency bus for either Unit 1 or Unit 2.

Additions subsequent to the original station area radiation monitoring system include the spent resin handling area, laundry, and radwaste facilities. These systems are powered from reliable power supplies and are indicated and source tested locally.

The alarm setpoint of each area monitor is variable and is set at a level slightly above the normal background radiation level in the respective area.

The area radiation monitoring system consists of the detectors listed in Table 11.3-7, plus each unit's containment particulate and gas monitors, described below.

Criticality monitors are not required in the spent fuel and new fuel storage and handling areas. An exemption from the criticality monitoring requirements specified in 10 CFR 70.24(a) was received from the NRC for the storage and handling of fuel assemblies enriched up to 4.3 weight percent U-235 (Reference 8). The exemption was based on station design features and procedural controls that are in place to preclude an inadvertent criticality. Area radiation monitors are provided in these areas which would alert personnel to excessive radiation levels and would initiate appropriate response actions.

11.3.4.2 Containment Particulate Monitors

This channel continuously withdraws a sample from the containment atmosphere into a closed, shielded system exterior to the containment. The sample is passed through a moving filter paper with a collection efficiency of 99% for particle sizes greater than 1.0 micron. The amount of deposited activity is continuously scanned by a lead-shielded beta scintillation detector with a sensitivity of 1×10^{-11} μCi/cm^3 for particulates in a background of 2.5 mR/hr. The sample system, which is common to both the particulate and gas monitors, includes a pump with a 0.75-hp motor, a flow meter, automatic pressure protecting valves, a flow regulating valve, and isolation valves. The pump and motor are located outside the containment. A sample point is available for taking a sample of the containment atmosphere after an incident for spectrum analysis in the laboratory. During refueling a high-activity alarm automatically trips the containment purge air supply fans and closes the purge system butterfly valves, thus isolating the purge system. This automatic function is not credited in the fuel handling accident nor is it required to be functional. The operability of the containment particulate monitor is relied upon in conjunction with the containment gas monitor, the manipulator crane area monitor, and communications to provide a timely and valid indication of a fuel handling accident in the containment. The counting rate of the limiting isotopes, I-131 and Cs-137, is nominally 2.6×10^{12} cpm/μCi/cm^3 (2 scfm and 1"/hour tape speed).

11.3.4.3 Containment Gas Monitors

This channel takes the continuous containment atmosphere sample, after it has passed through the particulate filter paper, and draws it through an in-line, easily removable, charcoal cartridge arrangement to the containment gas monitor assembly, which is a fixed-volume, lead-shielded sampler enclosing a beta scintillation detector. The sensitivity of this detector is 1×10^{-6} μCi/cm^3 for noble gases in a background of 2.5 mR/hr. The sample activity is measured, and then the sample is returned to the containment.

During refueling, a high-activity alarm automatically trips the containment purge air supply fans and closes the purge system butterfly valves, thus isolating the purge system. This automatic function is not credited in the fuel handling accident nor is it required to be functional. The operability of the containment gas monitor is relied upon in conjunction with the containment particulate monitor, the manipulator crane area monitor, and communications to provide a timely and valid indication of a fuel handling accident in the containment.

A purge valve arrangement blocks the normal sample flow to permit purging the detector with a clean sample for calibration. Purged gases are discharged to the containment. Protection and isolation are provided as described in Section 11.3.4.2.

The counting rates of the limiting isotopes Xe-133, and Kr-85 are nominally 3.145×10^7, and 1.09×10^8 cpm/μCi/cm^3, respectively.

11.3.4.4 **Other Area Radiation Monitoring Equipment**

This equipment consists of fixed-position, ion-chamber-type gamma detectors and associated electronic equipment. These channels warn personnel of any increase in radiation level at locations where personnel may be expected to remain for extended periods of time. The channels and their ranges are listed in Table 11.3-7.

In addition, if the dose rate at the manipulator crane area monitor exceeds the alarm setpoint during refueling, the alarm automatically trips the containment's purge air supply fans and closes the purge system butterfly valves, thus isolating the purge system. This automatic function is not credited in the fuel handling accident nor is it required to be functional. The operability of the manipulator crane area monitor is relied upon in conjunction with the containment gas and particulate monitors, and communications to provide a timely and valid indication of a fuel handling accident in the containment.

Finally, the operability of the fuel pit bridge area monitor is relied upon in conjunction with the ventilation vent No. 2 particulate and gas monitors and communications to provide a timely and valid indication of a fuel handling accident in the spent fuel pool.

11.3.4.5 **High-Range Postaccident Containment Monitors**

A high-range reactor containment area monitor is located outside the containment structure. The detector is permanently mounted and aimed at the personnel hatch. The monitor has a range of 0.1 to 10^7 mR/hr to measure the expected high gamma dose rate in the containment following a LOCA.

An additional set of two high-range containment radiation monitors is installed at separate locations on the crane wall above the operating deck level inside containment. The monitors are single ion chamber detectors that measure photons over the range of 1 to 10^7 R/hr. The system is sensitive to photon energies from 60 keV to 3 MeV, with ±20% accuracy for 0.1 to 3 MeV photons.

The readout for the in-containment monitors is located in the control room and consists of a rate meter and recorder that starts at a present value. Each redundant monitor is powered by a separate vital instrument bus.

The in-containment monitors meet the Seismic Class 1 requirements of Regulatory Guide 1.100 (Reference 5), will withstand the LOCA conditions specified by Regulatory Guide 1.89 (Reference 6), and have been environmentally qualified in accordance with the requirements of IEEE 323-1974 and Regulatory Guide 1.97, Revision 3.

11.3.4.6 **Technical Support Center Area Monitor**

The Technical Support Center (TSC) radiation monitoring system is a localized system and satisfies the guidelines established in NUREG-0696. The radiation monitoring system components consist of one particulate, iodine, and noble gas monitor, two area monitors and a remote alarm panel.

This monitoring system provides continuous indication of the dose rate and airborne activity in the TSC during an emergency, as well as alerting personnel of adverse conditions. It is totally contained within the TSC and is in no way connected to the control room or any safety-related systems.

11.3.5 Environmental Survey Program

The information in this section gives the programmatic elements of the Radiological Environmental Monitoring Program (REMP) for Surry Power Station. Historical data is provided on the pre-operational radiological surveillance performed in support of the Applicant's Environmental Report. Current requirements of the REMP program contained in Technical Specifications are implemented through the Offsite Dose Calculation Manual (ODCM), which describes the specific elements of the present radiological environmental surveillance program at Surry Power Station.

The Surry Power Station Applicant's Environmental Report contains the preoperational radiological surveillance program covering the period from May 1968 through June 1970.

Comments made by the U.S. Fish and Wildlife Service concerning the preoperational phase of the station were taken into account by:

1. Holding a conference on June 21, 1968, to discuss the pre- and postoperational surveys for the Surry Power Station. Representatives from the following agencies were present:

   a. Federal Water Pollution Control Authority.

   b. Bureau of Commission of Fisheries, Radiobiological Laboratory.

   c. Virginia State Water Control Board.

   d. Commonwealth of Virginia, Bureau of Industrial Hygiene.

   e. Virginia Commission of Game and Inland Fisheries.

   f. U.S. Fish and Wildlife Service, Bureau of Sport Fisheries and Wildlife.

   g. Virginia Institute of Marine Science.

   The meeting adjourned with the understanding that all agencies represented at the meeting were completely satisfied with the Company's program for pre- and postoperational radiological and ecological surveillance programs.

2. Conducting the preoperational radiological surveillance program in such a manner that indigenous species that concentrate radionuclides are routinely sampled and analyzed.

3. Preparing reports on the radiological program for distribution to interested agencies before station operation.

4. Holding discussions with appropriate state officials and personnel from the U.S. Fish and Wildlife Service regarding thermal pollution.
5. Installing of seven platforms in the James River upon which are seven instruments continuously measuring water temperature. (Instruments to measure river salinity were also installed on those same towers.)
6. Working in conjunction with personnel from the Virginia Institute of Marine Science regarding their grant from the AEC concerning thermal pollution of the river.
7. Designing the intake water facility with a 1.0-fps intake velocity at the screen surface so as to prevent significant damage to fishery resources.

A postoperational radiation surveillance program was developed using the knowledge and information obtained from the preoperational surveillance program. The latter was in effect over a 2-year period and served to train plant personnel in sampling and analytical techniques; aid in identifying those “indicator samples” that may be an indication of a slow buildup of radioactivity in the environment; establish the degree of variability between measurements resulting from seasonal changes in the weather (since fluctuations do occur and are expected); generate meaningful environmental data based primarily on scientific and technical requirements; and establish a correlation of data between the consulting service and the station’s laboratory group.

The ultimate objective of the postoperational surveillance program is the verification of the adequacy of radiation source control. Therefore, analytical efforts are directed toward those samples that have the ability to concentrate the radioelements of concern and afford an integrated and sensitive sampling mechanism. Milk, shellfish (oysters, crabs, and clams), and silt are considered indicator samples and are indicative of radioactivity levels in the environment. Commercial and/or recreationally important species of fish (catfish, eel and perch) are selected for sampling in the vicinity of the discharge point. The consumption of fish present a direct ingestion pathway to man. Because certain species of fish, such as bottom feeders, concentrate radionuclides which may be taken up from the water and aquatic sediments or may accumulate in the fish directly via internal deposition, it is important to include these organisms in the radiological environment sampling program. Samples are collected from the environment surrounding the station at various intervals throughout the year. Radioanalysis of these samples indicates conditions both in time and space, and thus a slow buildup of radioactivity can be determined. In addition, comparison in the trends of radioactivity levels are more meaningful, since the biological variation caused by using many different media has been eliminated.

Since the program’s origination, sampling has been expanded to include obtaining representative samples of the sediment, shoreline silt, food products, oysters, fish and clams from the surrounding area. These samples are analyzed for radioisotopes.

11.3.5.1 **Air Monitoring**

To meet the surveillance objective previously stated, it is desirable for the surveillance methods to indicate changes in radioactivity above-background levels. Therefore, continuous-duty air particulate samplers are also used to confirm that the station presents no hazard to the public. An air-sampling station is located at different locations including a control location which provides background data. The establishment of the air particulate network takes into account the following four general considerations:

1. The average meteorological conditions in the vicinity of the site.
2. The current and projected population densities near the station.
3. The proximity of other nuclear facilities.
4. The proximity of the site boundary location of the highest calculated annual average ground level D/Q.

Air particulate matter is accumulated for a 1-week period on appropriate filter media using a low-volume air sampler. The particulate filters are analyzed in accordance with Radiological Environmental Monitoring Program requirements.

11.3.5.2 **Milk**

The dose consequence to an individual is from both a direct and indirect exposure pathway. The direct exposure pathway is from the inhalation of radioactive material and the indirect exposure pathway is from the grass-cow-milk pathway. In this pathway radioactive material is deposited on the plants consumed by the dairy animals. The radioactive material is them passed on to the individual via the milk.

It has been estimated that, since a cow grazes over an area of 160 m^2 per day (Reference 7), cow’s milk affords a good integrated sample. Since milk is one of the best and most direct biosamplers for determining the radiocesium, radiostrontium, and radioiodine levels in the environment, samples are collected from the local dairy farms in the vicinity of the station.

11.3.5.3 **Shellfish, Crabs, and Fish**

Shellfish have the ability to concentrate certain stable elements and radionuclides far above the normal concentrations found in their saline water environment. Oysters and clams, *Crasostrea virginica* and *Mercenaria mercenaria* respectively, found in the James River are thus one of the more sensitive mechanisms for the determination of radioactivity released from the station. Oysters and clams are collected in the vicinity of the station. Crab and fish samples are obtained in the vicinity of the station. Radioanalysis of these sample media are in accordance with the Radiological Environmental Monitoring Program.

Additional aquatic vectors useful as integrating samples have been investigated, but none have proven to be as sensitive or indicative as shellfish.

11.3.5.4 Silt and Sediment

Since shellfish do not concentrate all radionuclides, river bottom sediment samples are collected from downstream areas which have or potentially may have recreational value. Silt samples are obtained in the vicinity of the station. Because of the interaction of a number of mechanisms, radionuclides accumulate in silt and bottom sediments. Because of this, silt is one of the few environmental media in which radioactive effluents from nuclear power stations are usually detected. These samples thus afford an integrated indication of average water concentrations.

11.3.5.5 Water Samples

Water samples are collected for analysis from the following sources: surface water samples from two different locations—one upstream and one downstream from the station and ground (well) water samples, which are collected from various wells in the vicinity of the station. The well water and surface water samples are analyzed in accordance with Radiological Environmental Monitoring Program requirements.

11.3.5.6 Food Products

The dose consequence to an individual from food products is via the ingestion exposure pathway. Samples of food products are obtained from farms in the vicinity of the station and analyzed in accordance with Radiological Environmental Monitoring Program requirements.

11.3.5.7 Equipment

Analytical equipment used for the Radiological Environmental Monitoring Program includes the following:

1. Gas-flow proportional counter (alpha-beta counter).
2. Multichannel gamma spectroscopy analyzer.
3. Liquid scintillation counter.
4. Thermoluminescent Dosimeter (TLD) readers.
5. Other analytical equipment which meet the Lower Limit of Detection (LLD) requirements set forth in the Offsite Dose Calculation Manual.

11.3.5.8 Environmental Dosimetry

Normally, the gaseous wastes discharged from the station consist almost entirely of the noble gases, xenon and krypton. The radiation hazard from these gases, due to their inertness, is external radiation exposure. Therefore, radiation surveillance can be maintained by using devices to measure total external body radiation levels in the station environs. The TLDs measure external radiation exposure from several sources including naturally occurring radionuclides in the air, radiation from cosmic origin, fallout from atomic weapons testing as well as potential radioactive airborne releases from Surry Power Station. An inner ring of TLDs are located in the five mile range from the site with a station in each of the 16 sectors of each ring. Other TLDs are located in special program interest areas (residences, schools, etc.) and in control locations. The TLDs are collected and analyzed for gamma radiation at a frequency which optimizes statistical sensitivity and characterizes seasonal fluctuations.

11.3.5.9 **Interlaboratory Comparison Program**

Surry Power Station participates in an Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of measurements of radioactive material in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring. The program is applicable for the radioanalyses performed in support of the Radiological Environmental Monitoring Program.

11.3.6 Control Room

The control area is described in Section 7.7. The design basis for radiation protection in the control room under accident conditions is that the whole body radiation dose to personnel accessing and occupying the control room is limited to less than or equal to 5 rem TEDE for the duration of the accident. This dose includes the 30-day dose from ECCS leakage (including RWST backleakage) and the contribution from the postulated radioactive plume leaking from the containment (as discussed in Section 14.5.5) until engineered safeguards equipment returns the containment to subatmospheric pressure and terminates the leakage.

The control room doses for the design basis LOCA are discussed in Section 14.5.5.3.

The control room walls, which are a minimum of 24-inch thick for tornado missile protection, provide more than adequate shielding from radiation. Special consideration has been given to the design of penetrations and structural details of the control room so as to establish an acceptable condition of leaktightness.

The air conditioning systems are installed within the spaces served and are designed to provide uninterrupted service under accident conditions. Upon a safety injection signal, the normal replenishment air and exhaust systems are isolated automatically from the control room by tight closures in the ductwork. The control and relay rooms are provided with an emergency ventilation system fitted with particulate and impregnated charcoal filters to introduce cleaned outside air into the protected spaces. Within 1 hour of control room envelope isolation, procedures require the alignment of the control room emergency ventilation system to provide a filtered breathing air supply to the control room envelope. This can continue indefinitely to hold the area pressure above atmospheric to ensure outflow leakage.

The radiation level in the control room is measured by a gamma monitor to verify safe operating conditions.

As a secondary precaution, personnel air-packs are available in the control area.

11.3 REFERENCES

1. IE Bulletin 79-01, *Environmental Qualification of Class 1E Equipment*, 1979.
2. J. J. Dinunno et al., *Calculation of Distance Factors for Power and Test Reactors*, TID - 14844, U.S. Atomic Energy Commission, 1962.
3. Regulatory Guide 1.4, *Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors*, 1974.
4. NUREG-0578, *TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations*, 1979.
5. Regulatory Guide 1.100, *Seismic Qualification of Electric Equipment for Nuclear Power Plants*, 1977.
6. Regulatory Guide 1.89, *Qualification of Class 1E Equipment for Nuclear Power Plants*, 1974.
7. G. Wortley, *Contamination of Milk with Radionuclides Dispersed into the Biosphere*, a report submitted to the Joint FAO/WHO Expert Committee on Milk Hygiene, WHO Headquarters, Geneva, Switzerland, 1969.
8. Letter from G. Edison of the USNRC to J.P. O'Hanlon of Virginia Electric and Power Company dated July 15, 1998 (Serial No. 98-427), *Issuance of Revised Exemption from the Requirements of 10 CFR 70.24(a) - Surry Power Station, Units 1 and 2 (TAC Nos. MA0657 and MA0658).*
9. Letter from NRC to Vepco, *Subject: Steam Generator Program*, Surry Power Station, Units 1 and 2 dated August 17, 1977, Ser. No. 351.

11.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-066A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 1
	11548-FM-066A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 2
2.	11448-FM-090B	Flow/Valve Operating Numbers Diagram: Gaseous Waste Disposal System, Unit 1

Table 11.3-1
ALLOWABLE DOSE RATES

Zone Description	Maximum Dose Rate (mrem/hr)	Typical Locations
	Full-power operation	
Continuous access (Zone I)	0.75	Control room, outside surface of containment, and all turbine plant and administration areas
Periodic access (Zone II)	2.5	Auxiliary and fuel building passageways in general and inside reactor containment personnel lock
Limited access (Zone III)	15	Outside surface of shielded tank shields
Controlled access (Zone IV)	15	Inside shielded equipment compartments
Access to incore instrumentation	100	Annulus between crane wall and containment wall
Access to incore instrumentation	40	Vicinity of incore instrumentation transfer devices
Access to incore instrumentation	20	Vicinity of incore instrumentation motors
	Hot shutdown (after 15-min decay)	
Limited access (Zone III)	15	Reactor containment above charging floor and outside of crane wall
Controlled access (Zone IV)	15	Inside shielded equipment compartments
	Cold shutdown for maintenance (after 8-hr decay)	
Periodic access (Zone II)	2.5	Reactor containment above charging floor and outside of crane wall
Controlled access (Zone IV)	15	Inside shielded equipment compartments
	Cold shutdown for refueling (after 4-day decay)	
Periodic access (Zone II)	2.5	Reactor containment above charging floor, outside of crane wall, and adjacent to fuel transfer canal near incore instrumentation devices
Controlled access (Zone IV)	15	Inside shielded equipment compartments
Surface of water over raised fuel elements	50	Fuel element above up-ender, and above other fuel elements in fuel building

Table 11.3-2
CONTAINMENT SHIELDING SUMMARY

Symbol	Figure	Shield Description	Material[a]	Thickness (inches)
			Water	34
A	11.3-2	Neutron shield tank	Steel	3
B	11.3-2	Primary shield	Concrete	54
C	11.3-2	Supplementary neutron shield	Benelex 70	14
D	11.3-2	Streaming shield ring	Benelex 401	5
			Steel	1-1/2
E	11.3-2	Neutron shield tank support	Lead	2
F	11.3-1 & 11.3-2	Cubicle - crane support wall	Concrete	33
G	11.3-2	Crane support wall	Concrete	24
H	11.3-1 & 11.3-2	Containment wall	Concrete	54
I	11.3-2	Containment dome	Concrete	30
J	11.3-2	Floor elevation, 3' 6"	Concrete	24
K	11.3-2	Charging floor	Concrete	24
L	11.3-1 & 11.3-2	Refueling cavity wall	Concrete	36
	11.3-2		Concrete (Unit 1)	24
M	11.3-3	Missile shield	Steel (Unit 2)	2
N	11.3-2	Refueling cavity water	Water	-
O	11.3-2	Removable block wall	Concrete (Ilmenite)	12
P	11.3-1	Fuel trans. canal wall	Concrete	54
Q	11.3-1	Fuel trans. canal wall	Concrete	72
R	11.3-1	Fuel trans. tube shielding	Concrete	36
S	11.3-1	Fuel trans. canal wall	Concrete	72
T	11.3-1	Incore inst. cubicle wall	Concrete	42
U	11.3-1	Cubicle wall	Concrete	30
V	11.3-1	Regen. heat exchanger wall	Concrete	24
W	11.3-1	Cable vault wall	Concrete	24
X	11.3-1	Auxiliary feed pump cubicle wall	Concrete	36
Y	11.3-1	Safeguards area wall	Concrete	24
Z	11.3-3	Incore Sump Room Drain	Steel	3.5
AA	11.3-2	Incore Sump Room Drain	Steel	3.5
BB	11.3-2 & 11.3-3	Incore Instrumentation	Lead	1.5

a. All concrete is reinforced with steel.

Table 11.3-3
N-16 AND ACTIVATED CORROSION PRODUCT ACTIVITY
USED IN THE ORIGINAL PLANT SHIELDING DESIGN ANALYSIS

Isotope	Activity ($\mu Ci/cm^3$ at 500°F)
Mn-54	$2.7 \times 10\text{-}3$
Mn-56	$5.7 \times 10\text{-}2$
Fe-59	$8.3 \times 10\text{-}3$
Co-58	$2.3 \times 10\text{-}4$
Co-60	$9.2 \times 10\text{-}4$
N-16[a]	64.0

a. At the reactor vessel outlet nozzle at 2546 MWt (power level for the original plant shielding design analysis).

Table 11.3-4
POSTACCIDENT MITIGATION PHASE SOURCE TERMS

Source	Source Term	Basis
Sump water	0% noble gas	Sump water is degassed
	50% halogens	TID-14844
	1% solid fission products	TID-14844
Primary coolant sample	100% noble gas	R.G. 1.4/TID-14844
	50% halogens	TID-14844
	1% solid fission products	TID-14844
Containment atmosphere	100% noble gas	R.G. 1.4/TID-14844
	25% halogens	R.G. 1.4
	0% solid fission products	R.G. 1.4

Table 11.3-5
PROCESS RADIATION MONITORING SYSTEM[a]

Monitor	Number	Type of Detector	Medium	Limiting Isotopes	Sensitivity (µci/cm^3)	Range (decades)	Maximum Background (mR/hr)
Process Vent Particulate (1-GW-RM-130A)	1	Silicon Diode	Gas, air	1-131	1×10^{-9} (I-131)	3	0.75
Process Vent Gas (1-GW-RM-130B)	1	Silicon Diode	Gas, air	I-131, Xe-133, Kr-85	5×10^{-6} (Kr-85)	4	0.75
Ventilation Vent No. 1 - Gas (1-VG-RM-104)	1	Beta scint.	Air	1-131. Xe-133, Kr-85	5×10^{-6} (Kr-85)	3	0.75
RF Vent Particulate[c] (1-RRM-RE-100)	1	Beta scint.	Gas, air	Cs-137	1.92E-12 (Cs-137)	5	<1
RF Vent Gas[c] (1-RRM-RE-101)	1	Beta scint.	Gas, air	Xe-133	5.12E-7 (Xe-133)	5	<1
Component Cooling Water (1-CC-RM-105, 106)	2	Gamma scint.	Water	Co-60, Cs-137	1×10^{-5} (Cs-137)	3	0.75
Comp. Cooling Hx Service Water (1-SW-RM-107A, B, C, D)	4	Gamma scint.	Water	Co-60, Cs-137	1×10^{-5} (Cs-137)	3	0.75
RF Liquid Waste Disposal[b,d] (1-RRM-RE-131)	1	Gamma scint.	Water	CS-137	1×10^{-7} (Cs-137)	5	<1
Condenser Air Ejector (1/2-SV-RM-111/211)	2	Gamma scint.	Vapor	I-131, Xe-133, Kr-85	1.74×10^{-5} (Kr-85)	5	0.75

a. This table contains information based on the requirements stated in the various specifications for the listed monitors. The actual monitors meet or exceed these minimum requirements except 1-RRM-RE-100 and 1-RRM-RE-101.
b. These channels also have local readout and alarm.
c. Based upon Sensitivity Calculated IAWX-S-001376-001, Revision 0, Specification for Radiation Monitoring System.
d. Based upon Sensitivity Calculated IAW X-S-001376-001, Revision 0, Specification for Radiation Monitoring System. Sensitivity values are based upon RP Sensitivity and Efficiency Calculation SU-16-01083 in accordance with RP-AA-151.

Table 11.3-5 (CONTINUED)
PROCESS RADIATION MONITORING SYSTEM[a]

Monitor	Number	Type of Detector	Medium	Limiting Isotopes	Sensitivity ($\mu ci/cm^3$)	Range (decades)	Maximum Background (mR/hr)
Steam Generator Blowdown[b] (1/2-SS-RM-112/212 &113/213)	4	Gamma scint.	Water	Co-60, Cs-137	4×10^{-6} (Cs-137)	3	2.5
Recirculation Spray Cooler (1/2-SW-RM-114/214, 115/215, 116/216, & 117/217)	8	Gamma scint.	Water	Co-60, Cs-137	3×10^{-4} (Cs-137)	2	5.0
R.C. Letdown High Range[b] (1/2-CH-RM-118/218)	2	Gamma scint.	Water	Co-60, mixed fission products	1×10^{-1} (Co-60)	4	2.5
R.C. Letdown Low Range[b] (1/2-CH-RM-119/219)	2	Gamma scint.	Water	Co-60, mixed fission products	1×10^{-4} (Co-60)	4	2.5
C.W. Discharge Tunnel (1/2-SW-RM-120/220)	2	Gamma scint.	Water	Co-60, Cs-137	2×10^{-7} (Cs-137)	3	0.05
Ventilation Vent No. 2 - Particulate (1-VG-RM-131A)	1	Silicon Diode	Air	I-131	1×10^{-9} (I-131)	3	0.75
Ventilation Vent No. 2 - Gas (1-VG-RM-131B)	1	Silicon Diode	Air	I-131, Xe-133, Kr-85	5×10^{-6} (Kr-85)	3	0.75
Laundry Facility Continuous Effluent - Particulate (1-RM-RMS-RIC3)	1	Beta scint.	Air	I-131, Cs-137	1×10^{-10} (I-131)	5	0.5

a. This table contains information based on the requirements stated in the various specifications for the listed monitors. The actual monitors meet or exceed these minimum requirements except 1-RRM-RE-100 and 1-RRM-RE-101.

b. These channels also have local readout and alarm.

c. Based upon Sensitivity Calculated IAWX-S-001376-001, Revision 0, Specification for Radiation Monitoring System.

d. Based upon Sensitivity Calculated IAW X-S-001376-001, Revision 0, Specification for Radiation Monitoring System. Sensitivity values are based upon RP Sensitivity and Efficiency Calculation SU-16-01083 in accordance with RP-AA-151.

Table 11.3-5 (CONTINUED)
PROCESS RADIATION MONITORING SYSTEM[a]

Monitor	Number	Type of Detector	Medium	Limiting Isotopes	Sensitivity (μci/cm^3)	Range (decades)	Maximum Background (mR/hr)
Continuous Effluent - Iodine (1-RM-RMS-RIC4)	1	Beta scint.	Air	I-131	1×10^{-10} (I-131)	5	0.5

a. This table contains information based on the requirements stated in the various specifications for the listed monitors. The actual monitors meet or exceed these minimum requirements except 1-RRM-RE-100 and 1-RRM-RE-101.
b. These channels also have local readout and alarm.
c. Based upon Sensitivity Calculated IAWX-S-001376-001, Revision 0, Specification for Radiation Monitoring System.
d. Based upon Sensitivity Calculated IAW X-S-001376-001, Revision 0, Specification for Radiation Monitoring System. Sensitivity values are based upon RP Sensitivity and Efficiency Calculation SU-16-01083 in accordance with RP-AA-151.

Table 11.3-6
PROCESS RADIATION MONITORING SYSTEM COUNTING RATES OF LIMITING ISOTOPES (cpm/µCi/cm^3)

Monitor	I-131	Xe-133	Kr-85	Cs-137	Co-60
Process Vent Particulate	1.04E+9	-	-	1.15E+9	7.1E+8
Process Vent Gas	2.28E-6	1.7E-6	2.92E-6	-	-
Ventilation Vent No. 1 - Gas	-	2.2×10^7	9.5×10^7	-	-
RF Vent Particulate	-	-	-	6.41E10	-
RF Vent Gas	-	3.35E7	9.40E7	-	-
Ventilation Vent No. 2 - Part.	1.04E+9	-	-	1.15E+9	7.1E+8
Ventilation Vent No. 2 - Gas	-	1.7E-6	2.92E-6	-	-
Component Cooling Water	-	-	-	1.0×10^8	2.0×10^8
Component Cooling HX Service Water	-	-	-	2.8×10^8	7.6×10^8
RF Liquid Waste Disposal[a]	-	-	-	4.20E+07	9.55E+07
Condenser Air Ejector	1.79×10^9	2.32×10^7	3.22×10^6	-	-
Steam Generator Blowdown	-	-	-	$1.0 \text{ x } 10^8$	2.0×10^8
Recirculating Spray Cooler	-	-	-	1.0×10^8	2.0×10^8
R.C. Letdown High Range	-	-	-	-	9.9×10^2
R.C. Letdown Low Range	-	-	-	-	9.6×10^5
C.W. Discharge Tunnel	-	-	-	4.2×10^8	1.1×10^9
Laundry Facility					
Continuous Effluent Part.	3.6×10^{10}	-	-	3.6×10^{10}	-
Continuous Effluent Iodine	4.1×10^9	-	-	-	-

a. Based upon RP Sensitivity and Efficiency Calculation SU-16-01083 in accordance with RP-AA-151.

Table 11.3-7
AREA RADIATION MONITORING LOCATIONS, NUMBER, AND RANGES

Channel Location (Number)	Range (mR/hr)
Containment personnel hatch area (2)	
1/2-RM-RMS-161/261	10^{-1}—10^{7}
Manipulator crane (2)	
1/2-RM-RMS-162/262	10^{-1}—10^{7}
Reactor containment area (2)	
1/2-RM-RMS-163/263	10^{-1}—10^{7}
Incore instrument transfer area (2)	
1/2-RM-RMS-164/264	10^{-1}—10^{7}
New fuel storage area (1)	
1-RM-RMS-152	10^{-1}—10^{7}
Fuel pit bridge (1)	
1-RM-RMS-153	10^{-1}—10^{7}
Auxiliary Building control area (1)	
1-RM-RMS-154	10^{-1}—10^{7}
Solid waste drum storage and handling area (1)	
1-RM-RMS-155	10^{-1}—10^{7}
Sample room (1)	
1-RM-RMS-156	10^{-1}—10^{7}
Main control room (1)	
1-RM-RMS-157	10^{-1}—10^{7}
Laboratory (1)	
1-RM-RMS-158	10^{-1}—10^{7}
Decontamination area (1)	
1-RM-RMS-151	10^{-1}—10^{7}
Spent resin handling area (2)	
1-RM-RMS-138, 139	10^{-2}—10^{3}
Laundry Facility (2)	
1-RM-RMS-RIC8, RIC9	10^{-2}—10^{3}
Radwaste Facility (10)	
1-RRM-RE-121 (RF control room)	
1-RRM-RE-122 (RF laboratory)	
1-RRM-RE-123 (RF DAW truck area)	
1-RRM-RE-124 (RF DAW sorting/compactor area)	
1-RRM-RE-125 (RF LSA box storage area)	
1-RRM-RE-126 (RF HIC storage and handling Area)	
1-RRM-RE-127 (RF hot machine shop truck bay)	
1-RRM-RE-128 (RF hot machine shop area)	
1-RRM-RE-129 (RF local control panel area)	
1-RRM-RE-130 (RF bitumen control room)	10^{-1}—10^{4}
Containment high range radiation monitor system (4)	
1/2-RM-RMS-127/227 & 128/228	10^{0}—10^{7} R/hr
Technical support center (2)	
1-RM-RMS-136, 137	10^{-1}—10^{4}

Table 11.3-8
HIGH-RANGE POST-ACCIDENT RADIATION MONITORS

Normal Range Noble Gas Effluent Monitors

Process Vent (1-GW-RM-130B)

Ventilation Vent No. 2 (1-VG-RM-131B)

High Range Noble Gas Effluent Monitors

Process Vent (1-GW-RM-130C)

Ventilation Vent No. 2 (1-VG-RM-131C)

High Range Effluent Monitors

Main Steam Lines

1-MS-RM-124 (1A)

1-MS-RM-125 (1B)

1-MS-RM-126 (1C)

2-MS-RM-224 (2A)

2-MS-RM-225 (2B)

2-MS-RM-226 (2C)

Auxiliary Feedwater Turbine Exhaust

1-MS-RM-129

2-MS-RM-229

Figure 11.3-1
SHIELD ARRANGEMENT, PLAN

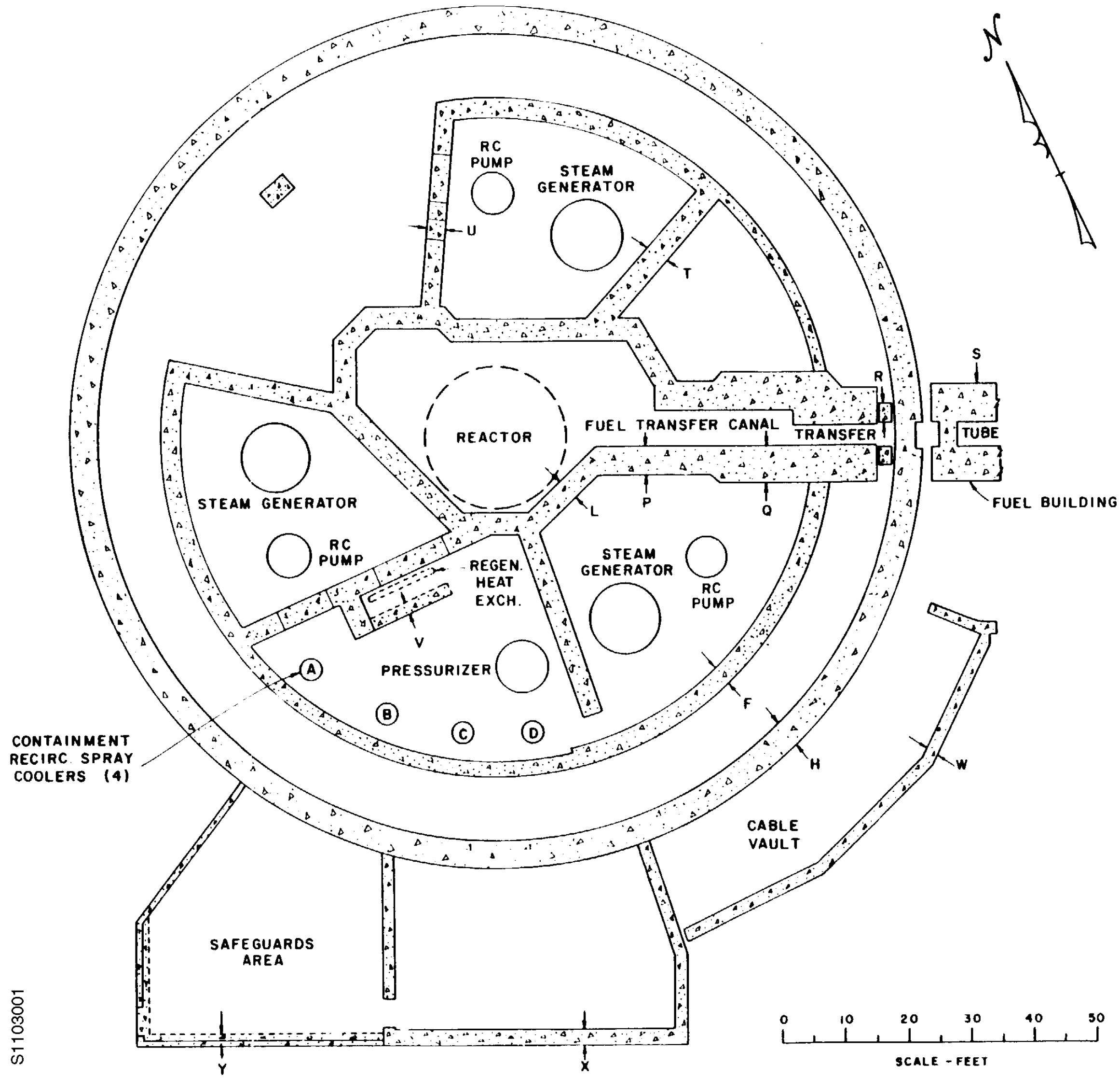
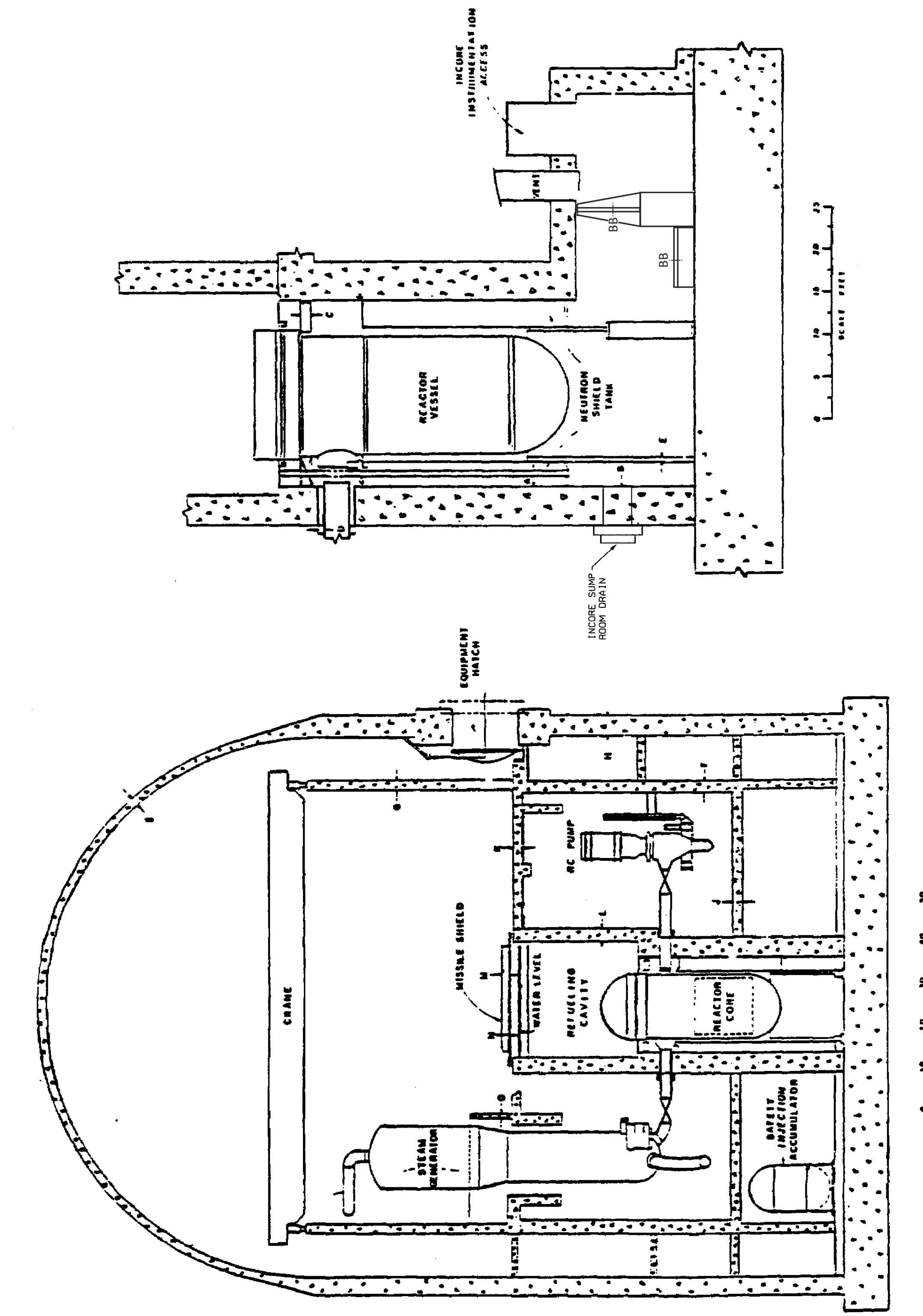
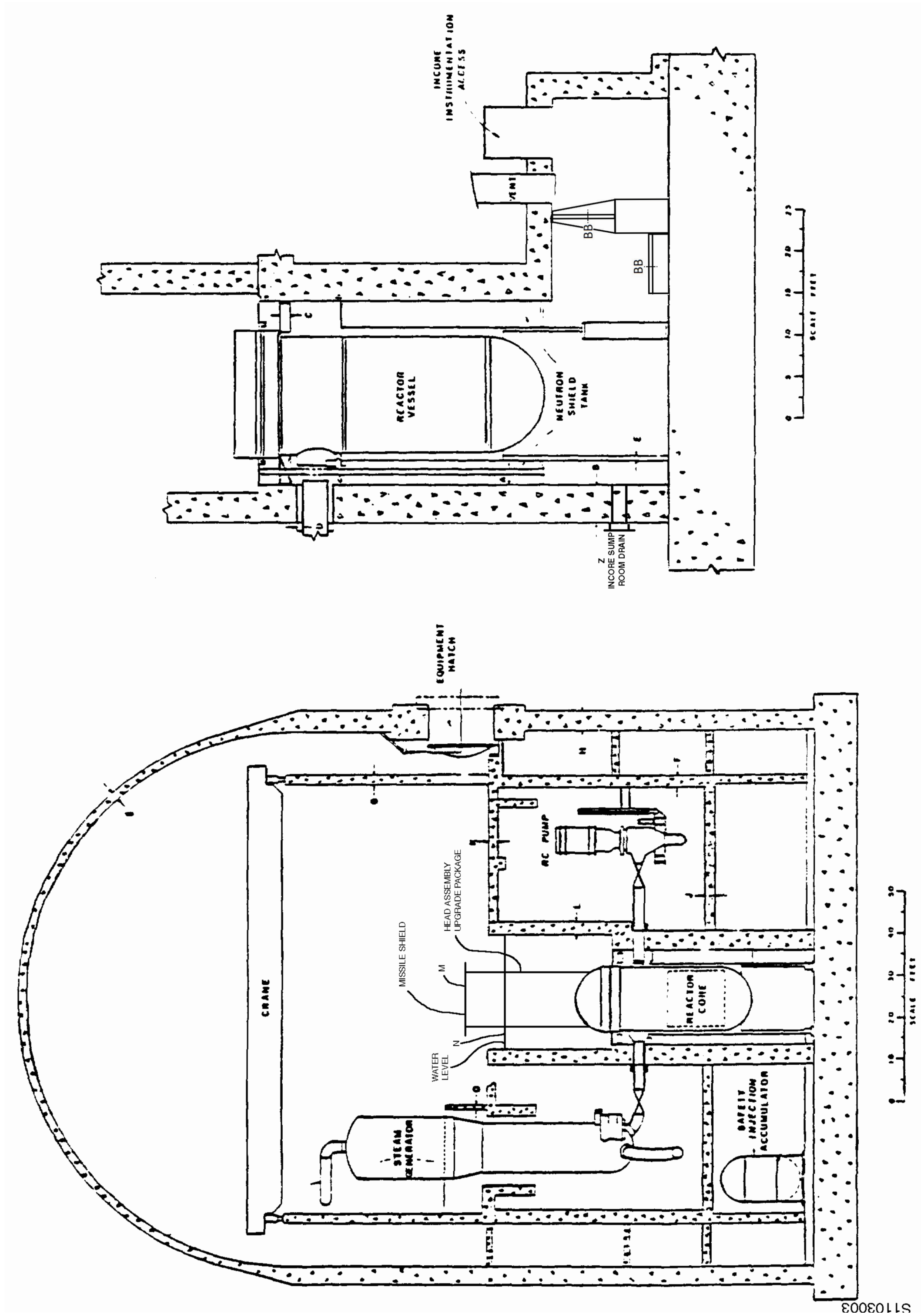


Figure 11.3-2
SHIELD ARRANGEMENT, ELEVATION, UNIT 1



SPS
26-FEB-2008 06:02
S1103002.HYB

Figure 11.3-3
SHIELD ARRANGEMENT, ELEVATION, UNIT 2



Intentionally Blank

Appendix 11A
Radiation Exposure Evaluation for Expected Radioactive Effluents

Intentionally Blank

APPENDIX 11A RADIATION EXPOSURE EVALUATION FOR EXPECTED RADIOACTIVE EFFLUENTS

11A.1 ANALYTICAL BASIS

Surry Units 1 and 2 were analyzed and evaluated using the parameters and methodology set forth in Regulatory Guides 1.109 (Reference 1), 1.111 (Reference 2), and 1.112 (Reference 3), and NUREG-0017 (Reference 4). Maximum individual doses resulting from gaseous and liquid effluents were calculated.

Radioactive source terms, both liquid and gaseous, were calculated in a manner consistent with Regulatory Guide 1.112 and NUREG-0017. Specific data used for the generation of the sources terms are presented in Section 11A.2.1.

Meteorological information used in the calculation of doses was developed consistent with the methodology described in Regulatory Guide 1.111. Information related to the meteorological inputs is contained in Section 11A.2.2. The dispersion factors (χ/Q) and ground depositions factors (D/Q) from the release points at Surry Units 1 and 2 to the various receptions are contained in Section 11A.2.3.

A plant and animal census is provided in Section 11A.3.

Dose calculations were performed in a manner consistent with Regulatory Guide 1.109. The NRC computer codes LADTAP and GASPAR were used to perform the calculations. The results of the analyses presented in Section 11A.4 support the Surry Power Station's capability of keeping the levels of radioactivity in effluents as low as reasonably achievable.

The liquid waste disposal system described Section 11.2.3 reflects changes in the liquid waste design used in the original Appendix I evaluation. Table 11.2-4, however, maintains the parameters used in the evaluation. This table was unchanged because the new liquid waste design was to be, at a minimum, equal to the previous system. In reality, improved performance was expected. Therefore, this analysis represents a conservative evaluation of offsite doses.

The gaseous waste disposal system is as described in 11.2.5.

11A.2 INPUT INFORMATION

General plant information, meteorological information, dispersion factors (χ/Q), and ground deposition factors (D/Q) are given in the following sections.

11A.2.1 General Plant Information

Plant information required by Appendix B of Regulatory Guide 1.112 is contained in Table 11A-1.

11A.2.2 Meteorological Information

Information concerning the onsite meteorological measurements program is found in Section 2.2.1.2.

Joint frequency distributions of wind speed and wind direction by atmospheric stability class are prepared monthly and annually, based on the format of Table 1 in Regulatory Guide 1.23 (Reference 5). Monthly and annual joint frequency distributions of 35-foot wind and $\Delta T_{150\text{ ft.} - 35\text{ ft.}}$ data are used as input for χ/Q and D/Q calculations for ground-level releases. Monthly and annual joint frequency distributions of 150-foot wind and $\Delta T_{150\text{ ft.} - 35\text{ ft.}}$ data are used as input for qualifying elevated release calculations of χ/Q and D/Q. The 2-year (1974-1976) data set was chosen as the most recent representative data set.

The meteorological data for the period 1974-1976 are considered to be representative of atmospheric transport and diffusion conditions of the site region on a long-term basis. The stability distribution based on $\Delta T_{150\text{ ft.} - 35\text{ ft.}}$ for the period March 3, 1974, to March 2, 1975, is consistent with the 2-year data period as used in this report (Table 11A-2). Comparison of annual wind roses for both the 35- and 150-foot levels indicates that the annual 2-year wind roses are consistent with the first year of data and are in general agreement with Richmond and Norfolk wind roses for the period January 1, 1969, to December 31, 1973 (Reference 6). The representativeness of the first year of the 2-year data set to the long-term meteorological conditions is discussed in Reference 6.

11A.2.3 Dispersion Factors and Ground Deposition Factors

Table 11A-3 provides χ/Q and D/Q values for ground-level and mixed-mode releases for the special appropriate distances as indicated in Section 11A.3 for each downwind sector. Tables 11A-4 and 11A-5 provide χ/Q and D/Q values associated with surface-level releases from the containment (considered as entrained in the building wake, and therefore a ground-level release) for the standard population distances. Tables 11A-6 and 11A-7 provide χ/Q and D/Q values associated with a process vent release from 3.048 m above one of the containment structures, or approximately 43 m above grade (considered as a mixed-mode release) for the standard population distances.

Dispersions factors (χ/Q) were calculated using a sector-average, straight-line model specified in Regulatory Guide 1.111. Ground deposition (D/Q) values were calculated according to Regulatory Guide 1.111. The mixed release mode was used as applicable for a release height of 3.05 m above the 40.1-m containment from a 0.08-m-diameter vent at an exit velocity of 30.5 m/s. Qualifying elevation release heights were adjusted for momentum stack downwash, and terrain rise, as described in Regulatory Guide 1.111.

The open terrain correction factor for χ/Q and D/Q values was applied in accordance with Figure 2 of Regulatory Guide 1.111. As described in References 2 and 3 and in Table 11A-8, the terrain is flat and rises to less than about 170 feet out to a distance of 50 miles near Richmond.

Therefore, straight-line airflow trajectory regimes are considered to reasonably represent dispersion conditions as related to annual χ/Q values in the vicinity of the Surry Power Station.

The calculation χ/Q and D/Q values were based on onsite meteorological data during the period March 3, 1974, to March 2, 1975, and May 1, 1975, to April 30, 1976. Representative joint frequency distributions were developed for ground-level or elevated releases from the station as follows:

1. Ground-level release χ/Q and D/Q calculations were based on meteorological tower observations of wind speed and direction at the 35-foot level and of temperature differential (delta T) between the 150- and 35-foot levels. These levels were selected to conservatively represent the transport and diffusion of surface releases in the vicinity of the plant, or for vent releases entrained in the building wake. The σ_z diffusion parameter was based on the curves in Figure 1 of Regulatory Guide 1.111.
2. Qualifying elevated release χ/Q and D/Q calculations were based on meteorological tower observations of wind speed and direction at the 150-foot level and of the same temperature differential (delta T) between the 150- and 35-foot levels, as representing the environment of the plume between its release height and the ground.

11A.3 PLANT AND ANIMAL CENSUS

The plant and animal census is conducted annually in order to determine the current land use of the area surrounding Surry Power Station. The purpose of the census is to locate the distance to the nearest milk cow or other bovine, milk goat, vegetable garden, and residence within 5 miles of the Surry Power Station. The annual land use is detailed in the current radiological environmental monitoring report.

11A.4 DOSE CALCULATIONS

11A.4.1 Doses From Liquid Effluents

Liquid source terms were calculated for two specific cases using the GALE Code: the liquid radwaste system as presently operating and as the system operated with the blowdown treatment system, which is no longer used. These cases are indicated below:

1. Dirty wastes treated by a system consisting of two mixed-bed demineralizers and no treatment of steam generator blowdown.
2. Same as 1 above, only steam generator blowdown treated by two mixed-bed demineralizers. (This equipment is no longer used.)

Inputs to the GALE Code were based on (1) station operating experience, (2) information supplied previously in Chapter 11 and the Environmental Report (ER) (References 8 & 9), and (3) NUREG-0017. Source terms for each of the two cases outlined above are presented in

Tables 11A-9 and 11A-10.

Liquid radioactive wastes from the units are released to the James River via the discharge canal. Possible pathways of exposure for release from the station include ingestion of fish and invertebrates and shoreline activities. The irrigated food pathway does not exist at this location, nor does the potable water pathway. For all pathways, a river dilution factor of 5 was assumed as appropriate per Regulatory Guide 1.109.

Doses from liquid pathways were calculated for the maximum individual, based on the models given in Regulatory Guide 1.109, using the computer code LADTAP. Dose factors, bioaccumulation factors, and shorewidth factors given in Regulatory Guide 1.109 and in the LADTAP code were used, as were usage terms for shoreline activities and ingestion of fish and invertebrates.

Tables 11A-11 and 11A-12 present the LADTAP input data and the maximum individual doses for both cases indicated above.

During normal station operations, doses from liquid effluents are calculated according to the Offsite Dose Calculation Manual (ODCM). Calculations from the ODCM demonstrate compliance with this section.

11A.4.2 Doses From Gaseous Effluents

Gaseous source terms were calculated using the GALE Code, and are presented in Table 11A-13. Inputs to the GALE Code were based on (1) plant operating experience, (2) information supplied in Chapter 11 and the ER, and (3) NUREG-0017.

Doses to the maximum individual from gaseous effluents were calculated by the NRC GASPAR Code, using the models of Regulatory Guide 1.109. Dose factors, annual air intake, intakes of food products, and parameters for calculating radionuclide concentrations in food products as given in Regulatory Guide 1.109 and in the GASPAR Code were used.

Dose contributions from the following pathways were calculated and analyzed in the assessment of the maximally exposed individual:

1. Immersion in the plume.
2. Ground contamination.
3. Inhalation.
4. Consumption of vegetables, meat, and milk.

For dose calculation purposes, the source terms of Table 11A-2 were divided into mixed-mode releases (i.e., those released from the Surry process vent that could be considered to be elevated at certain times and at ground level at others) and ground-level releases (i.e., those released from the ventilation vents, steam generator flash tank, and turbine building). The sources of releases for the Surry process vent are the gaseous waste and containment vacuum systems. For dose calculation purposes, these releases were considered mixed mode, and the χ/Q and D/Q values, as presented in Table 11A-3, reflect this.

The sources of releases from the ventilation vents of the Surry units are the auxiliary, decontamination, and spent fuel buildings, safeguards areas, condenser air ejector, and containment purge systems. For dose calculation purposes, these releases were considered ground level, and the χ/Q and D/Q values, as presented in Table 11A-3, reflect this.

Based on the χ/Q and D/Q values in Table 11A-3, specific locations were analyzed for the location of the maximally exposed individual. When the principal locations were determined, dose calculations were performed, incorporating the pathways specific to each location. By adding the doses resulting from both mixed-mode and ground-level releases for each of the pathways existing at these locations, the location of the maximum individual was determined.

After evaluating the special locations, the maximum organ dose occurred to an infant who resides 3.75 miles north-northwest of the power station and drinks milk from a cow raised at this location. The maximum total body dose occurred to an individual 1.53 miles south of the Surry Power Station. Table 11A-14 presents the doses at the location of the maximally exposed individuals for Surry Units 1 and 2.

Table 11A-15 presents the doses to the above-mentioned individual based on the cooling of steam generator blowdown below 212°F. Operation in this manner eliminates the gaseous releases of I-131 and I-133 from the blowdown vent offgas and results in a reduction of the maximum organ dose by a factor of 5.

During normal station operations, doses from gaseous effluents are calculated according to the Offsite Dose Calculation Manual (ODCM). Calculations from the ODCM demonstrate compliance with this section.

11A REFERENCES

1. Regulatory Guide 1.109, *Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I*, 1976.

2. Regulatory Guide 1.111, *Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors*, 1976.

3. Regulatory Guide 1.112, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water-Cooled Power Reactors*, 1976.

4. NUREG-0017, *Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents for Pressurized Water Reactors (PWR-GALE Code),* 1976.

5. Regulatory Guide 1.23, *Onsite Meteorological Program (Safety Guide 23)*, 1972.

6. Virginia Electric and Power Company, *Surry 3 and 4 Annual Meteorological Report*, Docket Nos. 50-434 and 40-435, 1975.

7. U.S. Atomic Energy Commission, *Surry Power Station Units 3 and 4 Final Environmental Statement*, Docket Nos. 50-434 and 50-435, 1974.

8. U.S. Atomic Energy Commission, *Surry Power Station Unit 1 Final Environmental Statement*, Docket No. 50-280, 1972.

9. U.S. Atomic Energy Commission, *Surry Power Station Unit 2 Final Environmental Statement*, Docket No. 50-281, 1972.

Table 11A-1
GENERAL PLANT INFORMATION*

	Units	Value	Source
General			
Maximum core thermal power evaluated for safety considerations in SAR	MWt	2441	Section 1.1
Quantity of liquid tritium released	Ci/yr	480	GALE Code calculations
Quantity of gaseous tritium released	Ci/yr	490	GALE Code calculations
Primary system			
Mass of coolant in primary system, excluding pressurizer and primary coolant purification system, at full power	10^3 lb	367	Calculations based on information in Tables 4.1-2, 4.1-3, 4.1-4, and 4.1-6
Average primary system letdown rate to primary coolant purification system	gpm	60	Table 9.1-3
Average flow rate through the primary coolant purification system demineralizer	gpm	6	Table 9.1-5
Average shim bleed flow	gpm	1.8	Unit operating experience
Secondary system			
Number of steam generators		3	Table 4.1-4
Type of steam generators		U-tube	Table 4.1-4
Carryover factor used for evaluation of iodine and non-volatiles		1% iodine 0.1% nonvolatiles	NUREG-0017
Total steam flow in secondary system	10^6 lb/hr	11.2	Figure 10.2-1
Mass of liquid in each steam generator at full power	10^3 lb	90.7	Calculations based on information in Table 4.1-4
Primary-to-secondary system leakage rate used in evaluation	lb/day	100	NUREG-0017
Average steam generator blowdown rate used in evaluation total	10^3 lb/hr	30.3	Unit operating experience

*This information was developed for the Appendix I Report, which was submitted to the NRC in Letter SN 247, dated June 17, 1977. This information was based on the original plant licensed power of 2441 MWt and has never been updated. Current compliance to 10 CFR 50 Appendix I requirements are documented through the Offsite Dose Calculation Manual and reported in accordance with Technical Specifications.

Table 11A-2

MONTHLY $\Delta T_{150\ ft\ -\ 35\ ft}$ STABILITY DISTRIBUTION (%)

Month	A	B	C	D	E	F	G
January 1975[a]	2.13	2.63	2.79	36.29	41.22	7.88	7.06
2-yr	10.07	2.19	2.42	32.08	39.73	5.93	7.57
February 1975	7.54	3.28	4.10	35.57	31.97	9.02	8.52
2-yr	11.88	3.83	3.35	25.68	34.53	9.65	11.08
March 1974-1975	20.68	4.46	5.36	32.29	28.12	4.02	5.06
2-yr	17.04	4.12	4.12	29.75	32.42	4.77	7.80
April 1974	14.92	2.44	4.26	21.77	40.79	8.37	7.46
2-yr	20.35	2.59	3.50	18.18	33.78	9.65	11.96
May 1974	21.26	4.42	4.42	24.25	32.24	7.42	5.99
2-yr	15.06	3.35	4.28	21.98	34.33	9.92	11.06
June 1974	17.26	4.99	3.12	25.57	34.51	5.41	9.15
2-yr	12.85	3.68	3.37	17.95	30.56	9.72	21.87
July 1974	15.47	5.56	6.91	19.67	31.83	8.56	12.01
2-yr	7.67	3.33	4.27	21.49	38.13	9.84	15.27
August 1974	10.01	3.65	5.28	29.50	37.89	6.77	6.90
2-yr	6.73	3.05	4.58	28.36	34.88	11.10	11.30
September 1974	14.12	5.24	4.37	26.93	33.77	7.57	8.01
2-yr	7.77	3.78	3.63	23.46	41.03	7.63	12.71
October 1974	15.80	2.66	2.24	17.62	25.73	14.13	21.82
2-yr	10.98	3.08	2.87	18.72	31.71	12.12	20.52
November 1974	16.74	4.08	3.52	21.38	29.11	13.22	11.95
2-yr	11.72	3.07	3.97	21.48	31.94	13.88	13.95
December 1974	16.95	4.89	3.02	27.01	34.48	7.61	6.03
2-yr	13.27	3.76	2.77	29.03	36.48	1.95	6.74

a. The first-year data period is March 3, 1974, to March 2, 1975, and the 2-year data period is the combined years of March 3, 1974, to March 2, 1975, and May 1, 1975, to April 30, 1976.

Table 11A-3
χ/Q AND D/Q VALUES AT SPECIAL DISTANCES
AND RELEASE MODES FOR A 2-YEAR DATA PERIOD[a]

		Ground-Level Release		Mixed-Mode Release (joint ground-level and elevated release)	
Receptor Direction	Distance (m)	χ/Q (sec/m^3)	D/Q (m^{-2})	χ/Q (sec/m^3)	D/Q (m^{-2})
NNE	2414	4.7 (-06)[b]	1.0 (-08)	3.9 (-07)	2.2 (-09)
NNE	3058	2.9 (-06)	5.9 (-09)	2.8 (-07)	1.3 (-09)
NE	2333	5.2 (-06)	1.1 (-08)	4.2 (-07)	3.3 (-09)
S	503	3.1 (-05)	1.7 (-07)	8.0 (-07)	3.5 (-08)
S	2470	1.5 (-06)	5.5 (-09)	3.1 (-07)	2.5 (-09)
SSW	3492	3.8 (-07)	1.4 (-09)	1.2 (-07)	7.7 (-10)
SW	2881	6.7 (-07)	2.0 (-09)	1.2 (-07)	9.7 (-10)
SW	3379	4.8 (-07)	1.4 (-09)	1.1 (-07)	6.6 (-10)
WSW	4828	2.0 (-07)	5.9 (-10)	6.8 (-08)	3.3 (-10)
NNW	6034	5.9 (-07)	5.9 (-10)	5.5 (-08)	1.2 (-10)
N	274	2.7 (-04)	5.9 (-07)	5.8 (-07)	2.6 (-08)
N	503	9.5 (-05)	2.2 (-07)	4.5 (-07)	1.7 (-08)
SSE	4747	4.1 (-07)	1.3 (-09)	7.5 (-08)	4.8 (-10)

a. Data period is March 3, 1974, to March 2, 1975, and May 1, 1975, to April 30, 1976. Open terrain corrective factors of Regulatory Guide 1.111 are incorporated.

b. 4.7 (-06) = 4.7×10^{-6}.

Table 11A-4

ANNUAL AVERAGE χ/Q (sec/m^3) VALUES BASED ON A GROUND-LEVEL RELEASE FOR A 2-YEAR DATA PERIOD[a]

Receptor	Distance in Meters									
Direction	805	2414	4023	5633	7242	12070	24140	40234	56327	72420
N	4.4 (-5)[b]	4.7 (-6)	1.7 (-6)	9.4 (-7)	6.2 (-7)	2.6 (-7)	1.1 (-7)	5.5 (-8)	3.6 (-8)	2.7 (-8)
NNE	4.4 (-5)	4.7 (-6)	1.7 (-6)	9.2 (-7)	6.1 (-7)	2.6 (-7)	1.0 (-7)	5.4 (-8)	3.6 (-8)	2.6 (-8)
NE	4.5 (-5)	4.8 (-6)	1.7 (-6)	9.5 (-7)	6.2 (-7)	2.6 (-7)	1.1 (-7)	5.6 (-8)	3.7 (-8)	2.7 (-8)
ENE	2.0 (-5)	2.1 (-6)	7.5 (-7)	4.1 (-7)	2.7 (-7)	1.1 (-7)	4.6 (-8)	2.4 (-8)	1.6 (-8)	1.1 (-8)
E	1.8 (-5)	1.9 (-6)	6.6 (-7)	3.6 (-7)	2.4 (-7)	9.9 (-8)	4.0 (-8)	2.1 (-8)	1.4 (-8)	1.0 (-8)
ESE	1.5 (-5)	1.5 (-6)	5.3 (-7)	2.9 (-7)	1.9 (-7)	7.8 (-8)	3.1 (-8)	1.6 (-8)	1.1 (-0)	7.8 (-9)
SE	1.5 (-5)	1.6 (-6)	5.5 (-7)	3.0 (-7)	1.9 (-7)	8.1 (-8)	3.3 (-8)	1.7 (-8)	1.1 (-8)	8.1 (-9)
SSE	1.6 (-5)	1.6 (-6)	5.6 (-7)	3.0 (-7)	1.9 (-7)	8.0 (-8)	3.2 (-8)	1.6 (-8)	1.1 (-8)	7.8 (-9)
S	1.5 (-5)	1.6 (-6)	5.3 (-7)	2.9 (-7)	1.8 (-7)	7.6 (-8)	3.0 (-8)	1.5 (-8)	1.0 (-8)	7.3 (-9)
SSW	8.1 (-6)	8.2 (-7)	2.8 (-7)	1.5 (-7)	9.4 (-8)	3.8 (-8)	1.5 (-8)	7.6 (-9)	4.9 (-9)	3.6 (-9)
SW	9.4 (-6)	9.5 (-7)	3.3 (-7)	1.0 (-7)	1.2 (-7)	4.8 (-8)	1.9 (-8)	9.7 (-9)	6.4 (-9)	4.6 (-9)
WSW	8.2 (-6)	8.2 (-7)	2.8 (-7)	1.5 (-7)	9.5 (-8)	3.9 (-8)	1.5 (-8)	7.8 (-9)	5.0 (-9)	3.7 (-9)
W	1.3 (-5)	1.3 (-6)	4.4 (-7)	2.4 (-7)	1.5 (-7)	6.3 (-8)	2.5 (-8)	1.3 (-8)	8.2 (-9)	6.0 (-9)
WNW	1.8 (-5)	1.9 (-6)	6.4 (-7)	3.5 (-7)	2.3 (-7)	9.4 (-8)	3.8 (-8)	2.0 (-8)	1.3 (-8)	9.3 (-9)
NW	2.1 (-5)	2.2 (-6)	7.8 (-7)	4.2 (-7)	2.8 (-7)	1.2 (-7)	4.6 (-8)	2.4 (-8)	1.6 (-8)	1.2 (-8)
NNW	3.3 (-5)	3.6 (-6)	1.3 (-6)	7.0 (-7)	4.6 (-7)	2.0 (-7)	7.9 (-8)	4.1 (-8)	2.7 (-8)	2.0 (-8)
	0.5 miles	1.5 miles	2.5 miles	3.5 miles	4.5 miles	7.5 miles	15.0 miles	25.0 miles	35.0 miles	45.0 miles

a. Data period is March 3, 1974 to March 2, 1975, and May 1, 1975, to April 30, 1976. Open terrain correction factors of Regulatory Guide 1.111 are incorporated.

b. 4.4 (-05) = 4.4×10^{-5}.

Table 11A-5

ANNUAL AVERAGE D/Q (M^{-2}) VALUES BASED ON A GROUND-LEVEL RELEASE FOR A 2-YEAR DATA PERIOD[a]

Receptor	Distance in Meters									
Direction	805	2414	4023	5633	7242	12070	24140	40234	56327	72420
N	9.7 (-08)[b]	7.3 (-09)	2.1 (-09)	9.9 (-10)	5.9 (-10)	2.0 (-10)	5.4 (-11)	2.0 (-11)	1.0 (-11)	6.2 (-12)
NNE	1.4 (-07)	1.0 (-08)	3.0 (-09)	1.4 (-09)	8.4 (-10)	2.8 (-10)	7.8 (-11)	2.9 (-11)	1.5 (-11)	8.9 (-12)
NE	1.4 (-07)	1.0 (-08)	3.0 (-09)	1.4 (-09)	8.3 (-10)	2.8 (-10)	7.6 (-11)	2.8 (-11)	1.4 (-11)	8.8 (-12)
ENE	6.4 (-08)	4.8 (-09)	1.4 (-09)	6.5 (-10)	3.9 (-10)	1.3 (-10)	3.6 (-11)	1.3 (-11)	6.7 (-12)	4.1 (-12)
E	6.0 (-08)	4.5 (-09)	1.3 (-09)	6.1 (-10)	3.6 (-10)	1.2 (-10)	3.3 (-11)	1.2 (-11)	6.2 (-12)	3.8 (-12)
ESE	6.0 (-08)	4.5 (-09)	1.3 (-09)	6.2 (-10)	3.7 (-10)	1.2 (-10)	3.4 (-11)	1.2 (-11)	6.3 (-12)	3.9 (-12)
SE	7.4 (-08)	5.5 (-09)	1.6 (-09)	7.6 (-10)	4.5 (-10)	1.5 (-10)	4.1 (-11)	1.5 (-11)	7.7 (-12)	4.7 (-12)
SSE	8.4 (-08)	6.3 (-09)	1.8 (-09)	8.6 (-10)	5.1 (-10)	1.7 (-10)	4.7 (-11)	1.7 (-11)	8.8 (-12)	5.4 (-12)
S	7.7 (-08)	5.7 (-09)	1.7 (-09)	7.9 (-10)	4.6 (-10)	1.5 (-10)	4.3 (-11)	1.6 (-11)	8.0 (-12)	4.9 (-12)
SSW	4.5 (-08)	3.3 (-09)	9.6 (-10)	4.6 (-10)	2.7 (-10)	9.0 (-11)	2.5 (-11)	9.1 (-12)	4.6 (-12)	2.9 (-12)
SW	4.0 (-08)	3.0 (-09)	8.8 (-10)	4.2 (-10)	2.5 (-10)	8.2 (-11)	2.3 (-11)	8.3 (-12)	4.2 (-12)	2.6 (-12)
WSW	4.1 (-08)	3.1 (-09)	8.8 (-10)	4.2 (-10)	2.5 (-10)	8.2 (-11)	2.3 (-11)	8.3 (-12)	4.3 (-12)	2.6 (-12)
W	6.4 (-08)	4.8 (-09)	1.4 (-09)	6.5 (-10)	3.9 (-10)	1.3 (-10)	3.6 (-11)	1.3 (-11)	6.7 (-12)	4.1 (-12)
WNW	7.0 (-08)	5.2 (-09)	1.5 (-09)	7.1 (-10)	4.2 (-10)	1.4 (-10)	3.9 (-11)	1.4 (-11)	7.3 (-12)	4.5 (-12)
NW	7.2 (-08)	5.4 (-09)	1.6 (-09)	7.3 (-10)	4.3 (-10)	1.4 (-10)	4.0 (-11)	1.5 (-11)	7.5 (-12)	4.6 (-12)
NNW	7.0 (-08)	5.3 (-09)	1.5 (-09)	7.2 (-10)	4.3 (-10)	1.4 (-10)	3.9 (-11)	1.4 (-11)	7.3 (-12)	4.5 (-12)
	0.5 miles	1.5 miles	2.5 miles	3.5 miles	4.5 miles	7.5 miles	15.0 miles	25.0 miles	35.0 miles	45.0 miles

a. Data period is March 3, 1974, to March 2, 1975, and May 1, 1915, to April 30, 1976. Open terrain correction factors of Regulatory Guide 1.111 are incorporated.

b. 9.7 (-08) = 9.7×10^{-8}.

Table 11A-6

ANNUAL AVERAGE χ/Q (SEC/M^3) VALUES BASED ON A MIXED-MODE RELEASE FOR A 2-YEAR DATA PERIOD[a]

Receptor Direction	Distance in Meters									
	805	2414	4023	5633	7242	12070	24140	40234	56327	72420
N	5.6 (-7)[b]	2.8 (-7)	1.4 (-7)	8.9 (-8)	6.8 (-8)	3.5 (-8)	1.2 (-8)	6.3 (-9)	4.1 (-9)	3.0 (-9)
NNE	8.8 (-7)	3.9 (-7)	1.8 (-7)	1.2 (-7)	8.9 (-8)	4.4 (-8)	1.4 (-8)	7.3 (-9)	4.8 (-9)	3.5 (-9)
NE	1.0 (-6)	3.9 (-7)	1.8 (-7)	1.1 (-7)	8.2 (-8)	4.1 (-8)	1.4 (-8)	6.9 (-9)	4.5 (-9)	3.3 (-9)
ENE	6.6 (-7)	2.3 (-7)	1.1 (-7)	6.6 (-8)	4.7 (-8)	2.4 (-8)	8.1 (-9)	4.1 (-9)	2.7 (-9)	2.0 (-9)
E	6.8 (-7)	2.3 (-7)	1.0 (-7)	6.4 (-8)	4.6 (-8)	2.3 (-8)	8.0 (-9)	4.1 (-9)	2.6 (-9)	1.9 (-9)
ESE	6.7 (-7)	1.9 (-7)	8.2 (-8)	5.3 (-8)	3.7 (-8)	1.8 (-8)	7.2 (-9)	3.7 (-9)	2.4 (-9)	1.7 (-9)
SE	7.5 (-7)	2.1 (-7)	9.1 (-8)	5.6 (-8)	4.0 (-8)	1.9 (-8)	7.1 (-9)	3.6 (-9)	2.3 (-9)	1.7 (-9)
SSE	7.3 (-7)	2.2 (-7)	9.5 (-8)	5.8 (-8)	4.0 (-8)	1.9 (-8)	6.7 (-9)	3.4 (-9)	2.2 (-9)	1.6 (-9)
S	8.7 (-7)	3.1 (-7)	1.4 (-7)	8.4 (-8)	5.9 (-8)	2.8 (-8)	8.6 (-9)	4.4 (-9)	2.8 (-9)	2.1 (-9)
SSW	6.2 (-7)	2.0 (-7)	8.9 (-8)	5.9 (-8)	4.3 (-8)	2.0 (-8)	6.6 (-9)	3.4 (-9)	2.2 (-9)	1.6 (-9)
SW	5.4 (-7)	1.6 (-7)	7.8 (-8)	4.8 (-8)	3.5 (-8)	1.7 (-8)	5.6 (-9)	2.9 (-9)	1.9 (-9)	1.4 (-9)
WSW	6.0 (-7)	1.7 (-7)	7.8 (-8)	5.3 (-8)	3.7 (-8)	1.9 (-8)	6.1 (-9)	3.1 (-9)	2.0 (-9)	1.5 (-9)
W	7.1 (-7)	2.3 (-7)	1.0 (-7)	6.7 (-8)	5.0 (-8)	2.3 (-8)	7.5 (-9)	3.8 (-9)	2.5 (-9)	1.8 (-9)
WNW	6.0 (-7)	2.3 (-7)	1.1 (-7)	6.6 (-8)	4.7 (-8)	2.3 (-8)	8.9 (-9)	4.5 (-9)	3.0 (-9)	2.2 (-9)
NW	7.5 (-7)	2.2 (-7)	1.0 (-7)	6.4 (-8)	4.6 (-8)	2.5 (-8)	9.2 (-9)	4.7 (-9)	3.1 (-9)	2.2 (-9)
NNW	4.4 (-7)	1.9 (-7)	9.6 (-8)	6.3 (-8)	4.7 (-8)	2.8 (-8)	9.8 (-9)	5.0 (-9)	3.3 (-9)	2.4 (-9)
	0.5 miles	1.5 miles	2.5 miles	3.5 miles	4.5 miles	7.5 miles	15.0 miles	25.0 miles	35.0 miles	45.0 miles

a. Data period is March 3, 1974, to March 2, 1975, and May 1, 1915, to April 30, 1976. Open terrain correction factors of Regulatory Guide 1.111 are incorporated.

b. 5.6 (-7) = 5.6×10^{7}.

Table 11A-7
ANNUAL AVERAGE D/Q (M^{-2}) VALUES BASED ON A MIXED-MODE RELEASE FOR A 2-YEAR DATA PERIOD[a]

Receptor Direction	Distance in Meters 805	2414	4023	5633	7242	12070	24140	40234	56327	72420
N	1.0 (-08)[b]	1.1 (-09)	3.4 (-10)	1.8 (-10)	1.2 (-10)	5.8 (-11)	2.4 (-11)	1.0 (-11)	5.9 (-12)	4.1 (-12)
NNE	2.0 (-08)	2.2 (-09)	6.7 (-10)	3.4 (-10)	2.2 (-10)	9.8 (-11)	3.8 (-11)	1.6 (-11)	9.3 (-12)	6.4 (-12)
NE	2.9 (-08)	3.0 (-09)	9.0 (-10)	4.5 (-10)	2.9 (-10)	1.2 (-10)	4.3 (-11)	1.9 (-11)	1.1 (-11)	7.0 (-12)
ENE	1.6 (-08)	1.7 (-09)	5.2 (-10)	2.6 (-10)	1.6 (-10)	6.4 (-11)	2.3 (-11)	9.9 (-12)	5.6 (-12)	3.7 (-12)
E	1.7 (-08)	1.8 (-09)	5.3 (-10)	2.6 (-10)	1.6 (-10)	6.4 (-11)	2.3 (-11)	9.7 (-12)	5.5 (-12)	3.6 (-12)
ESE	2.1 (-08)	2.2 (-09)	6.5 (-10)	3.2 (-10)	1.9 (-10)	7.2 (-11)	2.4 (-11)	1.0 (-11)	5.7 (-12)	3.7 (-12)
SE	2.5 (-08)	2.6 (-09)	7.6 (-10)	3.7 (-10)	2.3 (-10)	8.5 (-11)	2.9 (-11)	1.2 (-11)	6.7 (-12)	4.4 (-12)
SSE	2.1 (-08)	2.3 (-09)	6.9 (-10)	3.4 (-10)	2.1 (-10)	7.8 (-11)	2.7 (-11)	1.2 (-11)	6.5 (-12)	4.3 (-12)
S	2.3 (-08)	2.6 (-09)	7.9 (-10)	3.9 (-10)	2.4 (-10)	9.1 (-11)	3.2 (-11)	1.4 (-11)	7.9 (-12)	5.2 (-12)
SSW	1.5 (-08)	1.8 (-09)	5.3 (-10)	2.6 (-10)	1.6 (-10)	6.1 (-11)	2.1 (-11)	9.2 (-12)	5.2 (-12)	3.4 (-12)
SW	1.3 (-08)	1.4 (-09)	4.2 (-10)	2.1 (-10)	1.3 (-10)	4.8 (-11)	1.5 (-11)	7.0 (-12)	3.9 (-12)	2.6 (-12)
WSW	1.5 (-08)	1.6 (-09)	4.9 (-10)	2.4 (-10)	1.5 (-10)	5.4 (-11)	1.9 (-11)	8.0 (-12)	4.5 (-12)	2.9 (-12)
W	1.7 (-08)	1.9 (-09)	5.7 (-10)	2.8 (-10)	1.7 (-10)	6.5 (-11)	2.3 (-11)	9.7 (-12)	5.5 (-12)	3.6 (-12)
WNW	1.2 (-08)	1.3 (-09)	4.0 (-10)	2.0 (-10)	1.3 (-10)	5.2 (-11)	1.9 (-11)	8.2 (-12)	4.7 (-12)	3.2 (-12)
NW	2.5 (-08)	2.4 (-09)	7.1 (-10)	3.5 (-10)	2.2 (-10)	8.2 (-11)	2.8 (-11)	1.2 (-11)	6.5 (-12)	4.3 (-12)
NNW	9.3 (-08)	9.6 (-10)	2.9 (-10)	1.5 (-10)	9.9 (-11)	4.5 (-11)	1.8 (-11)	7.5 (-12)	4.3 (-12)	3.0 (-12)
	0.5 miles	1.5 miles	2.5 miles	3.5 miles	4.5 miles	7.5 miles	15.0 miles	25.0 miles	35.0 miles	45.0 miles

a. Data period is March 3, 1974 to March 2, 1975, and May 1, 1975, to April 30, 1976. Open terrain correction factors of Regulatory Guide 1.111 are incorporated

b. 1.0 (-08) = 1.0×10^{-8}.

Table 11A-8
0- TO 5-MILE HIGHPOINTS BY MILE AND 5- TO 10-MILE HIGHPOINTS FOR 16 CARDINAL POINTS FROM SURRY POWER STATION[a]

Section	0-1	1-2	2-3	3-4	4-5	5-10
N	37	-	-	12	55	80
NNE	37	5	2	-	71	100
NE	38	4	-	-	52	80
ENE	43	10	-	-	30	80
E	38	3	-	-	-	60
ESE	38	37	-	-	11	30
SE	39	36	-	-	-	-
SSE	39	33	39	37	37	50
S	37	39	50	51	60	80
SSW	42	38	42	70	85	90
SW	39	34	70	72	84	95
WSW	40	-	55	81	83	130
W	38	-	-	70	88	90
WNW	39	-	-	-	-	10
NW	38	-	-	6	5	80
NNW	39	-	-	12	47	110

a. All highpoints are measured in feet. Dash (-) denotes sea level.

Sources: Surry Power Station Units 3 and 4 Environment Report, Figures 2.6-8 through 2.6-11; and U.S. Geological Survey 7.5 minute topographic maps.

Table 11A-9
LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS)
WITHOUT STEAM GENERATOR BLOWDOWN PROCESSING

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
Corrosion And Activation Products											
CR51	2.78E+01	1.68E-03	2.11E-07	0.00257	0.00844	0.02643	0.00000	0.03744	0.03757	0.00000	0.03800
MN54	3.03E+02	2.74E-04	5.06E-08	0.00052	0.00138	0.00634	0.00000	0.00824	0.00827	0.00036	0.00860
FE55	9.50E+02	1.41E-03	1.77E-07	0.00271	0.00713	0.02214	0.00000	0.03199	0.03210	0.00000	0.03200
FE59	4.50E+01	8.84E-04	1.30E-07	0.00148	0.00445	0.01624	0.00000	0.02217	0.02225	0.00000	0.02200
CO58	7.13E+01	1.41E-02	1.80E-06	0.02492	0.07121	0.22509	0.00000	0.32124	0.32239	0.00144	0.32000
C060	1.92E+03	1.76E-03	2.27E-07	0.00340	0.00891	0.02845	0.00000	0.04077	0.04091	0.00313	0.04400
NP239	2.35E+00	1.09E-03	1.14E-07	0.00022	0.00512	0.01426	0.00000	0.01960	0.01967	0.00000	0.02000
Fission Products											
BR83	1.00E-01	4.97E-03	1.96E-07	0.00000	0.00498	0.02458	0.00000	0.02956	0.02967	0.00000	0.03000
BR84	2.21E-02	2.77E-03	3.29E-08	0.00000	0.00003	0.00412	0.00000	0.00415	0.00416	0.00000	0.00420
BR85	2.08E-03	3.22E-04	3.53E-10	0.00000	0.00000	0.00004	0.00000	0.00004	0.00004	0.00000	0.00004
RB86	1.87E+01	7.47E-05	1.07E-08	0.00018	0.01868	0.00134	0.00000	0.02019	0.02027	0.00000	0.02000
RB88	1.24E-02	2.14E-01	1.36E-06	0.00000	0.00218	0.17036	0.00000	0.17304	0.17367	0.00000	0.17000
SR89	5.20E+01	3.09E-04	5.17E-08	0.00053	0.00156	0.00647	0.00000	0.00856	0.00859	0.00000	0.00860
SR90	1.03E+04	8.82E-06	1.26E-09	0.00002	0.00004	0.00016	0.00000	0.00022	0.00022	0.00000	0.00022
Y90	2.67E+00	1.09E-06	7.31E-10	0.00002	0.00001	0.00009	0.00000	0.00011	0.00012	0.00000	0.00012
SR91	4.03E-01	6.35E-04	4.74E-08	0.00000	0.00210	0.00594	0.00000	0.00805	0.00808	0.00000	0.00810

Table 11A-9 (CONTINUED)
LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS)
WITHOUT STEAM GENERATOR BLOWDOWN PROCESSING

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
Fission Products											
Y91M	3.47E-02	3.82E-04	4.73E-08	0.00000	0.00136	0.00593	0.00000	0.00728	0.00731	0.00000	0.00730
Y91	5.88E+01	5.66E-05	7.73E-09	0.00011	0.00029	0.00097	0.00000	0.00137	0.00137	0.00000	0.00140
Y93	4.25E-01	3.31E-05	3.09E-09	0.00000	0.00011	0.00039	0.00000	0.00050	0.00050	0.00000	0.00050
ZR95	6.50E+01	5.30E-05	7.71E-09	0.00009	0.00027	0.00097	0.00000	0.00133	0.00133	0.00000	0.00130
NB95	3.50E+01	4.42E-05	7.84E-09	0.00009	0.00022	0.00098	0.00000	0.00129	0.00130	0.00000	0.00130
MO99	2.79E+00	7.61E-02	1.08E-05	0.02037	0.36131	1.35526	0.00010	1.73705	1.74331	0.00000	1.70000
TC99M	2.50E-01	4.80E-02	2.91E-05	0.01948	0.28162	3.64351	0.00019	3.94479	3.95902	0.00000	4.00000
RU103	3.96E+01	3.98E-05	5.20E-09	0.00007	0.00020	0.00065	0.00000	0.00092	0.00092	0.00005	0.00097
RH103M	3.96E-02	4.76E-05	3.10E-08	0.00007	0.00020	0.00389	0.00000	0.00416	0.00417	0.00000	0.00420
RU106	3.67E+02	8.63E-06	1.26E-09	0.00002	0.00004	0.00016	0.00000	0.00022	0.00022	0.00086	0.00110
RH106	3.47E-04	1.08E-05	8.89E-09	0.00002	0.00004	0.00111	0.00000	0.00118	0.00118	0.00000	0.00120
TE125M	5.80E+01	2.56E-05	2.32E-09	0.00004	0.00013	0.00029	0.00000	0.00046	0.00047	0.00000	0.00047
TE127M	1.09E+02	2.47E-04	2.30E-08	0.00045	0.00125	0.00288	0.00000	0.00457	0.00459	0.00000	0.00460
TE127	3.92E-01	8.32E-04	1.60E-07	0.00045	0.00315	0.02007	0.00000	0.02367	0.02375	0.00000	0.02400
TE129M	3.40E+01	1.24E-03	1.57E-07	0.00197	0.00622	0.01966	0.00000	0.02786	0.02796	0.00000	0.02800
TE129	4.79E-02	1.69E-03	9.07E-07	0.00127	0.00417	0.11370	0.00000	0.11914	0.11957	0.00000	0.12000

Table 11A-9 (CONTINUED)
LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS)
WITHOUT STEAM GENERATOR BLOWDOWN PROCESSING

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
Corrosion and Activation Products											
I130	5.17E-01	2.03E-03	1.77E-07	0.00000	0.00736	0.022112	0.00001	0.02950	0.02961	0.00000	0.03000
TE131M	1.25E+00	2.32E-03	2.38E-07	0.00011	0.01021	0.02985	0.00000	0.04018	0.04033	0.00000	0.04000
TE131	1.74E-02	1.17E-03	8.36E-07	0.00002	0.00187	0.10471	0.00000	0.10660	0.10699	0.00000	0.11000
I131	8.05E+00	2.41E-01	3.20E-05	0.02153	1.18990	4.01574	0.00312	5.23029	5.24915	0.00002	5.20000
TE132	3.25E+00	2.44E-02	2.77E-06	0.00825	0.11676	0.34691	0.00003	0.47196	0.47366	0.00000	0.47000
I132	9.58E-02	1.04E-01	1.46E-05	0.00851	0.19360	1.82326	0.00026	2.02562	2.03292	0.00000	2.00000
I133	8.75E-01	3.58E-01	3.61E-05	0.00060	1.48638	4.52219	0.00295	6.01212	6.03380	0.00000	6.00000
I134	3.67E-02	4.98E-02	8.93E-07	0.00000	0.00449	0.11191	0.00000	0.11640	0.11640	0.00000	0.12000
CS134	7.49E+02	2.18E-02	2.99E-06	0.07167	5.50343	0.37523	0.00003	5.95036	5.97182	0.00468	6.00000
I135	2.79E-01	1.89E-01	1.30E-05	0.00000	0.52153	1.62652	0.00069	2.14874	2.15649	0.00000	2.20000
CS136	1.30E+01	1.15E-02	1.37E-06	0.02321	2.85474	0.17198	0.00001	3.04995	3.06094	0.00000	3.10000
CS137	1.10E+04	1.57E-02	1.99E-06	0.05202	3.96259	0.24974	0.00002	4.26437	4.27975	0.00864	4.30000
BA137M	1.77E-03	1.72E-02	1.41E-05	0.04864	3.70502	1.77272	0.00002	5.52641	5.54634	0.00000	5.50000
BA140	1.28E+01	1.95E-04	2.49E-08	0.00023	0.00097	0.00312	0.00000	0.00433	0.00434	0.00000	0.00430
LA140	1.68E+00	1.38E-04	3.40E-08	0.00025	0.00072	0.00426	0.00000	0.00524	0.00526	0.00000	0.00530
CE141	3.24E+01	6.19E-05	7.86E-09	0.00010	0.00031	0.00098	0.00000	0.00139	0.00140	0.00000	0.00140
CE143	1.38E+00	3.70E-05	4.13E- 09	0.00000	0.00016	0.00052	0.00000	0.00068	0.00069	0.00000	0.00069

Table 11A-9 (CONTINUED)
LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS)
WITHOUT STEAM GENERATOR BLOWDOWN PROCESSING

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
Corrosion and Activation Products											
PR143	1.37E+01	4.44E-05	5.51 E-09	0.00006	0.00022	0.00069	0.00000	0.00097	0.00098	0.00000	0.00098
CE144	2.84E+02	2.91E-05	5.06E-09	0.00006	0.00015	0.00063	0.00000	0.00084	0.00084	0.00187	0.00270
PR144	1.20E-02	3.53E-05	3.41E-08	0.00006	0.00015	0.00427	0.00000	0.00447	0.00449	0.00000	0.00450
All Others		0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total (Except Tritium)		1.41E+00	1.67E-04	0.31637	20.35739	20.91034	0.00748	41.59157	41.74157	0.02244	42.00000
Tritium Release		480	Curies Per Year								

Table 11A-10

LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS) WITH STEAM GENERATOR BLOWDOWN PROCESSING[a]

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
Corrosion And Activation Products											
CR51	2.78E+01	1.68E-03	2.11E-07	0.00257	0.00044	0.00003	0.00000	0.01104	0.01118	0.00000	0.01100
MN54	3.03E+02	2.74E-04	5.06E-08	0.00058	0.00138	0.00001	0.00000	0.00191	0.00198	0.00036	0.00230
FE55	9.50E+02	1.41E-03	1.77E-07	0.00271	0.00713	0.00002	0.00000	0.00987	0.000994	0.00000	0.00990
FE59	4.50E+01	8.84E-04	1.30E-07	0.00148	0.00448	0.00002	0.00000	0.00594	0.00599	0.00000	0.00600
CO58	7.13E+01	1.41E-02	1.80E-06	0.02492	0.07121	0.00023	0.00002	0.09639	0.09707	0.00144	0.09900
C060	1.98E+03	1.76E-03	2.27E-07	0.00340	0.00891	0.00003	0.00000	0.01235	0.01243	0.00313	0.01600
NP239	2.35E+00	1.09E-03	1.14E-07	0.00022	0.00512	0.00001	0.00000	0.00536	0.00540	0.00000	0.00540
Fission Products											
BR83	1.00E-01	4.97E-03	1.96E-07	0.00000	0.00498	0.00002	0.00000	0.00501	0.00505	0.00000	0.05000
BR84	2.21E-02	2.77E-03	3.29E-08	0.00000	0.00003	0.00000	0.00000	0.00003	0.00003	0.00000	0.00003
RB86	1.87E+01	7.47E-03	1.07E-08	0.00018	0.01848	0.00001	0.00000	0.01887	0.01901	0.00000	0.01900
RB88	1.24E-02	2.14E-01	1.38E-06	0.00000	0.00218	0.00171	0.00000	0.00389	0.00398	0.00000	0.00390
SR89	5.40E+01	3.09E-04	5.17E-08	0.00053	0.00156	0.00001	0.00000	0.00209	0.00211	0.00000	0.00210
SR90	1.03E+04	6.82E-06	1.26E-09	0.00002	0.00004	0.00000	0.00000	0.00006	0.00006	0.00000	0.00006
Y90	2.67E+00	1.09E-06	7.31E-10	0.00002	0.00001	0.00000	0.00000	0.00002	0.00002	0.00000	0.00002
SR91	4.03E-01	6.35E-04	4.74E-08	0.00000	0.00210	0.00001	0.00000	0.00211	0.00213	0.00000	0.00210

a. Steam generator blowdown treatment system is no longer used.

Table 11A-10 (CONTINUED)
LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS)
WITH STEAM GENERATOR BLOWDOWN PROCESSING[a]

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
Fission Products											
Y91M	1.47E-02	3.82E-04	4.73E-08	0.00000	0.00136	0.00001	0.00000	0.00136	0.00137	0.00000	0.00140
Y91	5.88E+01	5.66E-05	7.73E-09	0.00011	0.00029	0.00000	0.00000	0.00040	0.00040	0.00000	0.00040
Y95	4.45E-01	3.31 E-05	3.09E-09	0.00000	0.00011	0.00000	0.00000	0.00011	0.00011	0.00000	0.00011
ZR95	6.50E+01	5.30E-05	7.71E-09	0.00009	0.00027	0.00000	0.00000	0.00036	0.00036	0.00000	0.00036
NB95	3.50E+01	4.42E-05	7.84E-09	0.00009	0.00022	0.00000	0.00000	0.00031	0.00031	0.00000	0.00031
MO99	2.79E+00	7.61E-02	1.08E-05	0.02037	0.36131	0.00136	0.00010	0.38314	0.38591	0.00000	0.39000
TC99M	2.50E-01	4.80E-02	2.91E-05	0.01948	0.28162	0.00364	0.00019	0.30493	0.30713	0.00000	0.31000
RU103	3.96E+01	3.98E-05	5.20E-09	0.00007	0.00020	0.00000	0.00000	0.00027	0.00027	0.00005	0.00032
RH103M	3.96E-02	4.76E-05	3.10E-08	0.00007	0.00020	0.00000	0.00000	0.00027	0.00027	0.00000	0.00027
RH106	3.67E+02	8.83E-06	1.26E-09	0.00008	0.00004	0.00000	0.00000	0.00006	0.00006	0.00086	0.00093
RH106	3.47E-04	1.08E-05	8.89E-09	0.00002	0.00004	0.00000	0.00000	0.00006	0.00006	0.00000	0.00027
TE125M	5.80E+01	4.56E-05	4.32E-09	0.00004	0.00013	0.00000	0.00000	0.00017	0.00017	0.00000	0.00170
TE127M	1.09E+02	2.47E-04	2.30E-08	0.00045	0.00125	0.00000	0.00000	0.00170	0.00171	0.00000	0.00360
TE127	4.92E-01	8.32E-04	1.60E-07	0.00045	0.00315	0.00004	0.00000	0.00362	0.00365	0.00000	0.00830
TE129M	3.40E+01	1.24E-03	1.57E-07	0.00197	0.00622	0.00004	0.00000	0.00822	0.00828	0.00000	0.00560
TE130	5.17E-01	2.03E-03	1.77E-07	0.00000	0.00736	0.00002	0.00001	0.00740	0.00745	0.00000	0.00750

a. Steam generator blowdown treatment system is no longer used.

Table 11A-10 (CONTINUED)
LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS)
WITH STEAM GENERATOR BLOWDOWN PROCESSING[a]

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
TE131M	1.25E+00	2.32E-03	2.38E-07	0.00011	0.01021	0.00003	0.00000	0.01036	0.01043	0.00000	0.01000
TE131	1.74E-02	1.17E-03	8.36E-07	0.00004	0.00187	0.00010	0.00000	0.00199	0.00401	0.00000	0.00200
Corrosion and Activation Products											
T131	8.05E+00	2.41E-01	3.20E-07	0.02153	1.18990	0.00402	0.00318	1.21857	1.28739	0.00002	1.20000
TE132	3.25E+00	2.44E-02	2.77E-06	0.00025	0.11876	0.00035	0.00003	0.12539	0.12630	0.00000	0.13000
T132	4.58E-04	1.04E-01	1.46E-05	0.00851	0.19360	0.00182	0.00026	0.20419	0.20567	0.00000	0.21000
T135	8.75E-01	3.58E-01	3.61E-05	0.00060	1.48538	0.00452	0.00295	1.49445	1.50328	0.00000	1.50000
T134	3.67E-02	4.98E-02	8.93E-07	0.00000	0.00449	0.00011	0.00000	0.00460	0.00463	0.00000	0.00460
CS134	7.49E+02	2.18E- 02	2.99E-06	0.07167	5.50343	0.00175	0.00003	5.57888	5.61929	0.00468	5.60000
T135	2.79E-01	1.892E-01	1.30E-05	0.00000	0.52153	0.00165	0.00089	0.52385	0.52764	0.00000	0.53000
CS136	1.40E+01	1.15E-02	1.47E-06	0.02321	2.85474	0.00172	0.00001	2.87968	2.90054	0.00000	2.90000
CS137	1.10E+04	1.57E-02	1.99E-06	0.05202	3.98459	0.00250	0.00004	4.01713	4.04625	0.00864	4.10000
BA137M	1.77E-03	1.78E-02	1.41E-05	0.04864	3.70502	0.00177	0.00002	3.75546	3.78266	0.00000	3.80000
BA140	1.28E+01	1.95E-04	2.49E-08	0.00023	0.00097	0.00000	0.00000	0.00121	0.00121	0.00000	0.00120
LA140	1.68E+00	1.38E-04	3.40E-08	0.00023	0.00072	0.00000	0.00000	0.00098	0.00099	0.00000	0.00099
CE 41	3.24E+01	6.19E-05	7.86E-09	0.00010	0.00031	0.00000	0.00000	0.00041	0.00041	0.00000	0.00041
CE143	1.38E+00	3.70E-05	4.13E- 09	0.00000	0.00016	0.00000	0.00000	0.00017	0.00017	0.00000	0.00017

a. Steam generator blowdown treatment system is no longer used.

Table 11A-10 (CONTINUED)
LIQUID SOURCE TERMS FROM SURRY UNITS 1 & 2 (PER UNIT BASIS)
WITH STEAM GENERATOR BLOWDOWN PROCESSING[a]

		Coolant Concentrations		Annual Releases To Discharge Canal							
Nuclide	Half-life (Days)	Primary (Micro Ci/ml)	Secondary (Micro Ci/ml)	Boron Rs (Curies)	Misc. Wastes (Curies)	Secondary (Curies)	Turb Bldg (Curies)	Total LWS (Curies)	Adjusted Total (Ci/yr)	Detergent Wastes (Ci/yr)	Total (Ci/yr)
PR143	1.37+01	4.44E-05	5.51E-09	0.00006	0.00022	0.00000	0.00000	0.00028	0.00028	0.00000	0.00028
CE144	2.84E+04	2.91E-05	5.06E-09	0.00006	0.00015	0.00000	0.00000	0.00020	0.00024	0.00187	0.00210
PR144	1.20E-02	3.53E-05	3.41E-08	0.00006	0.00015	0.00000	0.00000	0.00021	0.00021	0.00000	0.00021
All Others		3.22E-04	3.53E-10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total (Except Tritium)		1.41E+00	1.67E-04	0.31537	20.35739	0.02963	0.00748	20.71086	20.86086	0.02244	21.00000
Tritium Release		480	Curies Per Year								

a. Steam generator blowdown treatment system is no longer used.

Table 11A-11

LADTAP INPUT DATA AND RESULTS - MAXIMALLY EXPOSED INDIVIDUAL DOSE CALCULATIONS FOR SURRY UNITS 1 AND 2 (DEMINERALIZER RADWASTE SYSTEM WITHOUT STEAM GENERATOR BLOWDOWN TREATMENT)

			Usage Rates (kg/yr or hr/yr)		
Exposure Pathway	Dilution Factor	Transit Time (hr)	Adult	Teen	Child
Fish ingestion	5	24	21.0	16.0	6.9
Invertebrate ingestion	5	24	5.0	3.8	1.7
Shoreline use	5	0	12.0	67.0	14.0

	Dose Results (mrem/yr per unit)[a]					
	Adults			Teenagers		
Exposure Pathway	Total Body	GI-LLI	Skin	Total Body	GI-LLI	Skin
Fish ingestion	1.15 (-1)[b]	1.74 (-2)	-	6.63 (-2)	1.27 (-2)	-
Invertebrate ingestion	6.12 (-2)	2.02	-	5.47 (-2)	1.59	-
Shoreline use	3.28 (-3)	3.28 (-3)	3.82 (-3)	1.83 (-2)	1.83 (-2)	2.13 (-2)
	1.79 (-1)	2.04	3.82 (-3)	1.39 (-1)	1.62	2.13 (-2)

a. Doses to other individuals and organs are smaller than those presented.

b. 1.15 (-1) = 1.15×10^{-1}.

Table 11A-12

LADTAP INPUT DATA AND RESULTS - MAXIMALLY EXPOSED INDIVIDUAL DOSE CALCULATIONS FOR SURRY UNITS 1 AND 2 (MODIFIED LIQUID RADWASTE SYSTEM WITH STEAM GENERATOR BLOWDOWN TREATMENT)[a]

			Usage Rates (kg/yr or hr/yr)		
Exposure Pathway	Dilution Factor	Transit Time (hr)	Adult	Teen	Child
Fish ingestion	5	24	21.0	16.0	6.9
Invertebrate ingestion	5	24	5.0	3.8	1.7
Shoreline use	5	0	12.0	67.0	14.0

	Dose Results (mrem/yr per unit)[b]					
	Adults			Teenagers		
Exposure Pathway	Total Body	GI-LLI	Skin	Total Body	GI-LLI	Skin
Fish ingestion	1.06 (-1)[c]	7.22 (-3)	-	6.06 (-2)	5.16 (-3)	-
Invertebrate ingestion	2.81 (-2)	5.60 (-1)	-	2.15 (-2)	4.40 (-1)	-
Shoreline use	3.06 (-3)	3.06 (-3)	3.57 (-3)	1.71 (-2)	1.71 (-2)	2.00 (-2)
	1.37 (-1)	5.70 (-1)	3.57 (-3)	9.92 (-2)	4.62 (-1)	2.00 (-2)

a. Steam generator blowdown treatment system is no longer used.

b. Doses to other individuals and organs are smaller than those presented.

c. 1.06 (-1) = 1.06×10^{-1}.

Table 11A-13
GASEOUS SOURCE TERMS FROM SURRY UNITS 1 AND 2 (PER UNIT)

	Primary Coolant (Micro Ci/Gm)	Secondary Coolant (Micro Ci/Gm)	Gaseous Release Rate - Curies Per Year							
			Gas Stripping		Building Ventilation			Blowdown Vent Offgas	Air Ejector Exhaust	Total
			Shutdown	Continuous	Reactor	Auxiliary	Turbine			
Kr-83m	2.251E-02	8.325E-09	7.0E+00	0.0	0.0	0.0	0.0	0.0	0.0	7.0E+00
Kr-85m	1.173E-01	4.426E-08	3.9E+01	7.0E+00	1.0E+00	2.0E+00	0.0	0.0	2.0E+00	5.1E+01
Kr-85	6.233E-02	2.337E-08	2.1E+01	2.5E+02	3.0E+01	1.0E+00	0.0	0.0	0.0	3.0E+02
Kr-87	6.438E-02	2.299E-08	2.1E+01	1.0E+00	0.	1.0E+00	0.0	0.0	0.0	2.3E+01
Kr-88	2.139E-01	7.879E-08	7.1E+01	8.0E+00	2.0E+00	5.0E+00	0.0	0.0	3.0E+00	8.9E+01
Kr-89	5.379-03	2.017E-09	2.0E+00	0.0	0.0	0.0	0.0	0.0	0.0	2.0E+00
Xe-131m	8.252E-02	3.115E-08	2.7E+01	2.1E+02	2.9E+01	2.0E+00	0.0	0.0	1.0E+00	2.7E+02
Xe-133m	2.139E-01	8.074E-08	7.1E+01	1.6E+02	2.8E+01	5.0E+00	0.0	0.0	3.0E+00	2.7E+02
Xe-133	1.577E+01	5.865E-08	5.8E+03	2.5E+04	3.9E+03	3.3E+02	0.0	0.0	2.1E+02	3.5E+04
Xe-135m	1.398E-02	5.185E-09	5.0E+00	0.0	0.0	0.0	0.0	0.0	0.0	5.0E+00
Xe-135	3.695E-01	1.371E-07	1.2E+02	4.7E+01	9.0E+00	8.0E+00	0.0	0.0	5.0E+00	1.9E+02
Xe-137	9.662E-03	3.602E-09	3.0E+00	0.0	0.0	0.0	0.0	0.0	0.0	3.0E+00
Xe-138	4.731E-02	1.728E-08	1.6E+01	0.0	0.0	1.0E+00	0.0	0.0	0.0	1.7E+01
Total Noble Gases										3.6E+04
I-131	2.408E-01	3.207E-05	0.0	0.0	2.8E-03	3.8E-03	1.7E-03	1.6E-01	2.4E-02	1.9E-01
I-133	3.582E-01	3.611E-05	0.0	0.0	7.9E-04	5.7E-03	2.0E-03	1.8E-01	3.6E-02	2.2E-01
Tritium Gaseous Release			490 Ci/yr							

0.0 appearing in the table indicates release is less than 1.0 Ci/yr for noble gas, 0.0001 Ci/yr for I

AR-41 25 Curies/yr

C-14 8 Curies/yr

Table 11A-13 (CONTINUED)
GASEOUS SOURCE TERMS FROM SURRY UNITS 1 AND 2 (PER UNIT)

	Airborne Particulate Release Rate - Curies Per Year			
	Waste Gas System	Building Ventilation		
Nuclide		Reactor	Auxiliary	Total
Mn-54	4.5E-05	6.0E-05	1.8E-04	2.9E-04
Fe-59	1.5E-05	2.1E-05	6.0E-05	9.6E-05
Co-58	1.5E-04	2.1E-04	6.0E-04	9.6E-04
Co-60	7.0E-05	9.3E-05	2.7E-04	4.3E-04
Sr-89	3.3E-06	4.7E-06	1.3E-05	2.1E-05
Sr-90	6.0E-07	8.2E-07	2.4E-06	3.8E-06
Cs-134	4.5E-05	6.0E-05	1.8E-04	2.9E-04
Cs-137	7.5E-05	1.0E-04	3.0E-04	4.8E-04

Table 11A-14

MAXIMUM DOSES TO AN INDIVIDUAL RESULTING FROM GASEOUS EFFLUENTS FROM SURRY UNITS 1 AND 2 WITH STEAM GENERATOR FLASH TANK (MREM/YR PER UNIT)

	Location 2.17 miles SSW	Location 3.75 miles NNW
	Total Body	Organ Dose (thyroid)
A. Radioiodines and particulates[a]		
Ground	7.80 (-4)[b]	3.11 (-4)
Ingestion of vegetables	5.01 (-2)	-
Inhalation	3.31 (-3)	9.96 (-2)
Milk	-	1.67
	5.42 (-2)	1.77
	Total Body	Skin
B. Noble gases		
Plume (1.53 miles S)	1.32 (-1)	3.53 (-1)
C. Air doses		
(1.53 miles S)	Annual beta 5.67 (-1) mrad/yr	Annual gamma 2.20 (-1) mrad/yr
(Site boundary 0.31 miles N)	Annual beta 15.4 mrad/yr	Annual gamma 6.26 mrad/yr

a. Maximum organ dose occurs to an infant.

b. 7.80 (-4) = 7.80×10^{-4}

Table 11A-15

MAXIMUM DOSES TO AN INDIVIDUAL RESULTING FROM GASEOUS EFFLUENTS FROM SURRY UNITS 1 AND 2 WITH STEAM GENERATOR BLOWDOWN COOLED (MREM/YR PER UNIT)

	Location 2.17 miles SSW	Location 3.75 miles NNW
	Total Body	Organ Dose (thyroid)
D. Radioiodines and particulates[a]		
Ground	7.09 (-4)[b]	2.81 (-4)
Ingestion of vegetables	4.97 (-2)	-
Inhalation	3.25 (-3)	2.08 (-2)
Milk	-	3.00 (-1)
	5.37 (-2)	3.21 (-1)
	Total Body	Skin
E. Noble gases		
Plume (1.53 miles S)	1.32 (-1)	3.53 (-1)
F. Air doses		
(1.53 miles S)	Annual beta 5.67 (-1) mrad/yr	Annual gamma 2.20 (-1) mrad/yr
(Site boundary 0.31 miles N)	Annual beta 15.4 mrad/yr	Annual gamma 6.26 mrad/yr

a. Maximum organ dose occurs to an infant.

b. 7.09 (-4) = 7.09×10^{-4}

Surry Power Station
Updated Final Safety Analysis Report

Chapter 12

Intentionally Blank

Chapter 12: Conduct of Operations
Table of Contents

Intentionally Blank

CHAPTER 12 CONDUCT OF OPERATIONS

12.1 ORGANIZATIONAL STRUCTURE OF VIRGINIA ELECTRIC AND POWER COMPANY

12.1.1 Organization

12.1.1.1 Nuclear Participation by Vepco

Vepco has participated in nuclear power activities since the passage of the Atomic Energy Act of 1954. In 1954, Vepco participated in a series of studies with Stone & Webster Engineering Corporation. In 1955, Vepco commenced further studies with Carolina Power & Light Company, Duke Power Company, and South Carolina Electric & Gas Company. In 1956, these four companies formed Carolinas Virginia Nuclear Power Associates, Inc. (CVNPA), a nonprofit, membership organization. Subsequently, under the third-round invitation of the Reactor Demonstration Program, CVNPA built and operated the Carolinas-Virginia Tube Reactor (CVTR), a 65-MWt heavy-water moderated and cooled pressure tube reactor located at Parr, South Carolina. The CVTR achieved criticality for the first time in March 1963. From the early summer of 1964 to 1967, the CVTR produced electric power on a reliable basis. CVNPA, and Westinghouse Electric Corporation as its subcontractor, carried out an extensive research and development program for the NRC both before and after construction of the CVTR. The plant was decommissioned in 1967 after fulfilling the objectives of the program.

Vepco was a significant participant in the work of CVNPA from its incorporation. Employees of Vepco served on the CVNPA Board of Directors and on several of the management committees, including the Steering Committee, the Technical Advisory Committee, and the Manpower Committee. Four Vepco employees were associated with CVNPA on a resident basis and had an integrated total of 22 man-years of project experience in responsible positions relating to design, engineering, construction, operation, maintenance, health physics, and chemistry. Individual periods of resident service with CVTR ranged from 2 to 9 years. In addition, two employees of CVNPA joined the Vepco organization in 1967. These two men had a total of over 7 man-years of experience in the CVNPA organization in positions relating to the operation of the CVTR reactor station. Vepco also participated in the study of the practicality of converting the Savannah River "R" reactor with a member on the study team.

Vepco became affiliated along with many other utilities with the Atomics International Division of North American Rockwell Corporation in a joint effort to promote research and development of the first demonstration liquid-metal fast-breeder facility. In addition, Vepco participated in a study with Gulf General Atomics to develop the gas-cooled fast-reactor concept.

12.1.1.2 Operational Phase

The execution of the Surry Power Station project was solely the responsibility of Vepco. Vepco (hereafter referred to as Virginia Power) engaged Stone & Webster as its agent for engineering and construction and contracted with Westinghouse Electric Corporation for furnishing the nuclear steam supply systems, the nuclear fuel, and the turbine generators.

In addition to these, Virginia Power retained the following consultants:

Site geology, hydrology, and seismology - Dames & Moore, Inc.

Site meteorology, climatology and general nuclear consultation - NUS Corporation

12.1.1.2.1 Virginia Power Organization and Responsibility

The Site Vice President and his organization have full responsibility for maintaining the station as a functional part of the Virginia Power generation system and for operating the station in a reliable, competent manner consistent with the safety of the public, station personnel, and equipment. The station shall be operated in accordance with the license granted by the United States Nuclear Regulatory Commission (NRC), the Technical Specifications, the Updated Final Safety Analysis Report (UFSAR), and the Operational Quality Assurance Program.

The nuclear organization and key individuals' responsibilities are described in Chapter 17 (the Operational Quality Assurance Program). Additionally, station personnel will meet the qualification requirements as specified in the Station Technical Specifications and the Operational Quality Assurance Program.

12.2 TRAINING PROGRAM

12.2.1 General

Personnel to staff the Surry Power Station have been selected to ensure that each individual possesses the educational training and experience necessary to satisfactorily perform his assigned function. To augment the formal education, training and experience of station personnel, training programs have been instituted to familiarize employees specifically with the Surry facility. The training programs are administered by the Corporate Nuclear Training Department, and actual training is performed mainly by site employees, and some by contract personnel from vendor companies.

The principal objectives of the training programs are to ensure initial and continuing qualification of station personnel through effective training, to accommodate future growth, to comply with applicable regulations, and to use the training information contained in relevant guidance documents, including:

1. Administrative Procedures.
2. Title 10 of the Code of Federal Regulations (CFRs), Parts 50 and 55.
3. Surry Power Station Safety Analysis Report documents, including the Updated Final Safety Analysis Report (UFSAR), Facility Operating License (FOL), Technical Specifications, and Operational Quality Assurance Program.
4. OSHA and other applicable regulatory requirements as specified in Titles 29, 40, and 49 of the Code of Federal Regulations.
5. Institute of Nuclear Power Operations (INPO) guidelines and good practices.
6. NRC inspections and INPO evaluations.

12.2.2 Program Description

12.2.2.1 Types of Training

Station personnel may be qualified through a combination of formal job training, on-the-job training, and special training. The types of training include:

1. Occupational training, which includes training efforts intended to develop job knowledge, skills, and employee development required for competent performance of assigned duties. This includes nuclear employee training, technical training, and employee development training.
2. Basic training, which is designed to provide an understanding of fundamentals, basic principles, and procedures involved in the work to which the employee is assigned.
3. Advanced training, which addresses topics typically taught to journeymen or supervisors.

4. Special training, which is site or equipment specific.
5. Periodic continuing training (requalification) designed to maintain the levels of occupational knowledge, skills, and employee development required to perform job duties. The continuing training program reinforces previous training and knowledge, and introduces new information as appropriate.
6. Backfit training, which is designed to remedy deficiencies in an employee's background.

12.2.2.2 **Training Methods**

Training is conducted using one or more of the following methods:

1. Formal job training, which is typically classroom training techniques directed at specific job skills and knowledge.
2. On-the-job training, conducted under the direction of appropriately experienced personnel.
3. Self-study training, where job skills and knowledge may be obtained on an individual basis.
4. Classroom training, which is formal training using a variety of instructional techniques and media and requires the trainees to demonstrate their comprehension of the material through discussions, tests, and/or skills performance.
5. Simulator training, which utilizes a plant-referenced simulator for reinforcement of classroom training and exercise of procedures.
6. Laboratory training, which provides actual hands-on experience in simulated job situations. The laboratory experiences are designed to provide structured and supervised methods of practicing the concepts, principles, and information taught in the classroom. Laboratory training is similar to on-the-job training.
7. Task training, which is designed to assist the trainee in becoming proficient in learning the basic to advanced job tasks.
8. In-house training, which is training conducted by an employee of Virginia Power.
9. Vendor training, which is training conducted by someone external to Virginia Power.

12.2.2.3 **Qualification of Personnel**

The cognizant director or manager is accountable for timely and effective qualification of assigned personnel. He is assisted by the Nuclear Training Department and by the Manager Nuclear Training.

The Nuclear Training Department administers standardized programs to meet station requirements, performs training needs assessments, develops methods and materials in support of nuclear programs, evaluates and arranges for vendor training programs for offsite or onsite presentations, and evaluates the overall effectiveness of the programs.

The station, through the Manager Nuclear Training:

1. Identifies training requirements, schedules, and types of training needed.
2. Schedules training consistent with station and regulatory requirements.
3. Conducts specific training segments on the site.
4. Maintains records of employee qualification, training, and experience.
5. Ensures the training and qualification of station personnel.
6. Makes applications for and maintains licenses and proper certifications required for station personnel.

The Nuclear Training Department, through the Manager Nuclear Training, administers operations staff and Shift Technical Advisor training programs which were originally accredited by the National Academy for Nuclear Training on October 24, 1985.

12.2 REFERENCES

1. U. S. Nuclear Regulatory Commission, NUREG-0737, *Clarification of TMI Action Plan Requirements*, October 31, 1980.

Intentionally Blank

12.3 EMERGENCY PLANNING

Virginia Power has formulated a comprehensive Station Emergency Plan for coping with all credible emergency situations at the Surry Power Station. The plan and changes thereto are contained in separately bound documents to facilitate future updating independent of the UFSAR.

The Emergency Plans and Implementing Procedures (EPIP) address the design, operation, and staffing of the offsite Corporate Emergency Response Center (CERC) and the onsite Technical Support Center (TSC) and Operational Support Center (OSC) using guidance contained in NUREG-0654 (Reference 1), NUREG-0696 (Reference 2), NUREG-0737 (including Supplement 1) (Reference 3), NEI 99-01 (Reference 7) and SECY-82-111 (Reference 4). The Station Emergency Plan is consistent with the NRC Standard Review Plan (Reference 5) (dated November 1974) and Regulatory Guide 1.101 (Reference 6) (dated November 1975). The Emergency Plan and supporting arrangements for assistance from pertinent Federal, State, and local agencies fully meet the requirements of Appendix E to 10 CFR 50. The Station Emergency Plan also outlines the emergency preparedness training program, including classroom instruction, practical exercises, and demonstrations.

12.3 REFERENCES

1. U.S. Nuclear Regulatory Commission, *NUREG-0654*, *Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants*, November 1980.
2. U.S. Nuclear Regulatory Commission, *NUREG-0696*, *Functional Criteria for Emergency Response Facilities*, February 1981.
3. U.S. Nuclear Regulatory Commission, *NUREG-0737*, *Clarification of TMI Action Plan Requirements*, October 31, 1980.
4. U.S. Nuclear Regulatory Commission, *SECY-82-111*, *Requirements for Emergency Response Capability*, March 11, 1982.
5. U.S. Nuclear Regulatory Commission, *NUREG-75/087*, *Standard Review Plan*, Section 13.3, *Emergency Planning*, dated November 1974.
6. U.S. Nuclear Regulatory Commission Regulatory Guide 1.101, *Emergency Planning for Nuclear Power Plants*, dated November 1975.
7. NEI 99-01, *Methodology for Development of Emergency Action Levels*, dated January 2003.

Intentionally Blank

12.4 REVIEW AND AUDIT

Specific review and audit requirements are assigned to various committees in addition to the review and audit requirements assigned to the Virginia Power Nuclear Oversight staff by the quality assurance program for station operation (see Chapter 17). The committees charged with specific review and audit functions are delineated in the facility's Nuclear Facility Quality Assurance Program Description (QAPD).

The Station Nuclear Safety and Operating Committee is charged with first-level review of station operations. The membership of the committee, committee responsibilities and authority, and quorum and meeting requirements are delineated in the QAPD. The members of this committee who are station supervisory personnel meet or exceed the qualification requirements of the QAPD.

Independent review of the safety of nuclear unit operation is performed for the Management Safety Review Committee by its Safety and Compliance Subcommittee. The organization and responsibilities of the Management Safety Review Committee are described in the QAPD.

Maintenance and modifications of safety-related equipment are controlled and documented in accordance with the requirements of a formal quality assurance program for station operation and other administrative controls formulated by written procedures. Audits of quality assurance programs are periodically conducted as delineated in the operational quality assurance program. The quality assurance programs pertinent to station operation are discussed in the QAPD.

Intentionally Blank

12.5 PLANT PROCEDURES

Detailed procedures for the following station operations have been prepared as recommended by Regulatory Guide 1.33 (Reference 1) and associated attachments:

- Administrative Procedures
- General Plant Operations
- System Operations
- Abnormal and Alarm Conditions
- Emergency Operations
- Radioactivity Control
- Measuring and Test Equipment Control
- Maintenance and Preventative Maintenance
- Chemical and Radiochemical Control

Other types of procedures not covered by this list may also be required during plant operation. However, procedures are subject to various controls to ensure that personnel are provided with accurate, usable guidance and information. These controls are discussed in the operational quality assurance program (Chapter 17). Action has also been taken to respond to guidance contained in NUREG-0737 (Reference 3) for evaluation and development of procedures for transients and accidents.

A continuing process of review, training, and practice drills, as detailed in the Technical Specifications and operational quality assurance program, maintain the functional effectiveness of the procedures. In addition, procedures are in place for the feedback of industry operating experience to the plant operations staff. Part of the feedback function is accomplished through the use of the INPO SEE-IN Program (Reference 4), which was endorsed by the NRC staff in Generic Letter 82-04 (Reference 5).

12.5 REFERENCES

1. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.33, *Quality Assurance Program Requirements (Operation)*, Revision 2, February 1978.
2. ANS-3.2/ANSI N18.7-1976, *Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants*.
3. U.S. Nuclear Regulatory Commission, *NUREG-0737, Clarification of TMI Action Plan Requirements*, October 31, 1980.
4. Institute of Nuclear Power Operations, SEE-IN, *Significant Event Evaluation and Information Network*, on going information exchange program.
5. U.S. Nuclear Regulatory Commission, Generic Letter 82-04, *Use of INPO SEE-IN Program*, March 9, 1982.

12.6 PLANT RECORDS

Records documenting the nuclear operation and maintenance of and modifications to the station shall be stored at a location approved by Virginia Power and in accordance with requirements in the operational quality assurance program (Chapter 17) governing the storage of Quality Assurance Records. Operating records will be maintained as delineated in regulatory requirements, the administrative controls section of the applicable unit’s Technical Specifications, and the Operational Quality Assurance Program commitments.

Intentionally Blank

12.7 INDUSTRIAL SECURITY

Physical protection of Surry Power Station Units 1 and 2 is based on controlling access to the facility, selecting station operating personnel, monitoring station equipment, designing and arranging station features, and obtaining assistance from local law enforcement authorities. Design of the security plan is guided by 10 CFR 73, Sections 55, 56, 57, Appendices B & C. Implementation of security procedures shall be in accordance with the approved station security plan. Protection of safeguards information is provided as described in 10 CFR 73.21.

Intentionally Blank

12.8 SHIFT PERSONNEL

The positions, qualifications, duties, and responsibilities of station personnel assigned to rotating shifts are described in, and implemented in accordance with, the Technical Specifications and administrative procedures. Technical Specifications and administrative procedures also define minimum shift crew requirements pursuant to guidance contained in NUREG-0737 (Reference 1) and NRC Generic Letter 82-10 (Reference 2). Overtime limits are administratively controlled in accordance with guidance contained in Generic Letter 82-12 (Reference 3).

12.8 REFERENCES

1. U.S. Nuclear Regulatory Commission, *NUREG-0737*, *Clarification of TMI Action Plan Requirements*, October 31, 1980.
2. U.S. Nuclear Regulatory Commission, Generic Letter 82-10, *Post-TMI Action Plan Requirements*, May 5, 1982.
3. U.S. Nuclear Regulatory Commission, Generic Letter 82-12, *Nuclear Power Plant Staff Working Hours*, June 15, 1982.

Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 13

Intentionally Blank

Chapter 13: Initial Tests and Operations
Table of Contents

Chapter 13: Initial Tests and Operations

List of Tables

CHAPTER 13 INITIAL TESTS AND OPERATION

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

13.1 TESTS PRIOR TO INITIAL REACTOR FUELING

The comprehensive testing program ensured that equipment and systems performed in accordance with design criteria prior to fuel loading. As the installation of individual components and systems was completed, they were tested and evaluated according to predetermined and approved written testing techniques, procedures, or check-off lists. Field and engineering analyses of test results were made to verify that systems and components were performing satisfactorily and to recommend corrective action, if necessary.

The program included tests, adjustments, calibrations, and system operations necessary to ensure that initial fuel loading and subsequent power operation could be safely undertaken. In general, the types of tests are classified as hydrostatic, functional, electrical, and operational. Functional tests verified that the system or equipment was capable of performing the function for which it was designed. Operational tests involved actually operating the system and equipment under design or simulated design conditions.

Whenever possible, these tests were performed under the same conditions as experienced under subsequent station operations. During systems tests for which unit parameters were not available and could not be simulated, the systems were operationally tested as far as possible without these parameters.

The remainder of the tests were performed when the parameters were available. Abnormal unit conditions were simulated during testing when such conditions did not endanger personnel or equipment, or contaminate clean systems. The detailed procedure took into account the predicted emergency or abnormal conditions involved in the test program, and appropriate measures were included in the procedure.

During the preoperational tests, piping systems were checked to ensure correct and satisfactory performance under normal operating conditions, including expected routine transients. Any abnormal conditions, such as water hammer, excessive vibration, or displacement were noted and referred to the start-up engineer for investigation. If no abnormal conditions were observed, the system was deemed to be satisfactory and no other action taken. Completed preoperational test procedures are maintained on file at the plant site.

For purpose of illustration, a listing of representative tests required prior to initial reactor fueling is contained in Table 13.1-1. Additional information on the preoperational testing of specific components and systems is contained in the inspection and tests subsections of Chapters 3 through 11. The quality assurance section (15.4.6) contains supplemental information concerning procedural and organizational matters during construction and start-up activities. The operational quality assurance program is discussed in Chapter 17.

Individual systems have system descriptions in which individual equipment tests are listed.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
1. Electrical system	To ensure continuity, circuit integrity, and the correct and reliable functioning of electrical apparatus. Electrical tests were performed on transformers, switchgear, turbine generators, motors, cables, control circuits, excitation switchgear, dc systems, annunciator systems, lighting distribution switchboards, communication systems, and miscellaneous equipment. Special attention was directed to the following tests: a. High-voltage switchgear breaker interlock test. b. Station loss of voltage autotransfer test. c. Emergency power transfer test. d. Tests of protective devices. e. Equipment automatic start tests. f. Excitor check for proper voltage buildup. g. Insulation tests.
2. Voice communication system	To verify proper communication between all local stations, for interconnection to commercial phone service, and to balance and adjust amplifiers and speakers.
3. Service water system	To verify, prior to critical operation, the design head-capacity characteristics of the service water system, that the system would supply design flow rate through all heat exchangers, and would meet the specified requirements when operated in the safeguards mode.
4. Fire protection system	To verify proper operation of the system by ensuring that the design intent was met for the fire pumps, to verify that automatic start functions operated as designed, and to verify that level and pressure controls met specifications.
5. Compressed air system	To verify leaktightness of the system, proper operation of all compressors, the manual and automatic operation of controls at design setpoints, design air dryer cycle time and moisture content of discharge air, and proper air pressure to each controller served by the system.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
6. Reactor coolant system cleaning	To flush and clean the reactor coolant and related primary systems to obtain the degree of cleanliness required for the intended service. Provisions to maintain cleanliness and protection from contaminated sources were made after system cleaning and acceptance. After systems were flushed clean of soluble and particulate matter, cleanliness of the system was maintained. Coolant was analyzed for chloride content, suspended solids, pH, and conductivity. Oxygen content was analyzed and brought to specifications before exceeding 200°F.
7. Ventilation system	To verify proper operability of fans, controls, and other components of the containment ventilation system and auxiliary ventilation system.
8. Condensate and system feedwater	To verify valve and control operability and set points. An inspection for completeness and integrity was made. Functional testing was performed when the main steam system was available. Flushing and hydrostatic tests were performed where applicable.
9. Auxiliary coolant systems	To verify component cooling flow to components, and to verify proper operation of instrumentation, controllers, and alarms. Specifically, each of the three systems (i.e., component cooling system, including the charging pump cooling system, residual heat removal system, and fuel pit cooling system) was tested to ensure that a. All manually and remotely operated valves were operable manually and/or remotely. b. All pumps performed their design functions satisfactorily. c. All temperature, flow, level, and pressure controllers functioned to control at the required setpoint when supplied with appropriate signals.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
9. Auxiliary coolant systems (continued)	d. All temperature, flow, level, and pressure alarms provided alarms at the required locations when the alarm setpoint was reached, and cleared when the reset point was reached. e. Design flow rates were established through the principal heat exchangers.
10. Boron recovery system	To verify valve and control operability and setpoints, flushing and hydrostatic testing were performed as applicable, including inspection for completeness and integrity. Functional testing was performed when a steam supply was available.
11. Chemical and volume control system	To verify, prior to critical operation, that the chemical and volume control system functioned as specified in the system description and appropriate manufacturers' technical manuals. More specifically, that a. All manually and remotely operated valves were operable manually and/or remotely. b. All pumps performed to specifications. c. All temperature, flow, level, and pressure controllers functioned to control at the required setpoint when supplied with appropriate signal(s). d. All temperature, flow, level, and pressure alarms provided alarms at the required locations when the alarm setpoint was reached and cleared when the reset point was reached. e. The reactor makeup control regulated blending, dilution, and boration as designed. f. The design seal-water flow rates were attainable at each reactor coolant pump. g. Chemical addition subsystem functioned as specified.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
12. Safety injection system	To verify, prior to critical operation, response to control signals and sequencing of the pumps, valves, and controllers of this system as specified in the system description and the manufacturers' technical manuals; and to check the time required to actuate the system after a safety injection signal was received. More specifically, that a. All manually and remotely operated valves were operable manually and/or remotely. b. For each pair of valves installed for redundant flow paths, disabling one of the valves did not impair operation of the other. c. All pumps performed their design functions satisfactorily. d. The proper sequencing of valves and pumps occurred on initiation of a safety injection signal. e. The fail position on loss of power for each remotely operated valve was as specified. f. Valves requiring initiating signals to operate did so when supplied with these signals. g. All level and pressure instruments were set at the specified points and provided appropriate alarms and resets. h. The time required to actuate the system was within the design specifications.
13. Containment spray system	To verify, prior to critical operation, response to control signals and sequencing of the pumps, valves, and controllers as specified in the system description and the manufacturers' technical manuals; and to check the time required to actuate the system after a containment high-pressure signal was received. More specifically, see the test objective listing for the safety injection system above.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
14. Fuel handling system[a]	To show that the system design was capable of providing a safe and effective means of transporting and handling fuel from the time it reaches the station until it leaves the station. In particular, the tests were designed to verify that a. The major structures required for refueling, such as the reactor cavity, refueling canal, new-fuel and spent-fuel storage, and decontamination facilities were in accordance with the design intent. b. The major equipment required for refueling, such as the manipulator crane, fuel-handling tools, and spent-fuel transfer system, operated in accordance with the design specifications. c. All auxiliary equipment and instrumentation functioned properly.
15. Radiation monitoring systems	To verify the calibration, operability, and alarm setpoints of all area radiation monitors, air particulate monitors, gas monitors, and liquid monitors that were included in the process radiation monitor system and the area radiation monitor system.
16. Reactor control and protection system	To verify calibration, operability, and alarm settings of the reactor control and protection system; to test its operability in conjunction with other systems. As an example, the nuclear instrumentation system tests are detailed below.
17. Nuclear instrumentation system	To ensure that the instrumentation system was capable of monitoring the reactor leakage neutron flux from source range through 120% of full power and that protective functions were operating properly. In particular, tests were designed to verify that a. All system equipment, cabling, and interconnections were properly installed.

a. Tests were conducted with a dummy fuel element.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
17. Nuclear instrumentation system (continued)	b. The source-range detector and associated instrumentation responded to neutron level changes and that the source-range protection (high-flux-level reactor trip), as well as alarm features and audible count rate, operated properly. c. The intermediate-range instrumentation operated properly; the reactor protective and control features, such as high-level reactor trip and high-level rod stop signals, operated properly; and the permissive signals for blocking source-range trip and source-range high-voltage-off operated properly. d. The power-range instrumentation operated properly; the protective features, such as the overpower trips, permissive, and dropped-rod functions, operated with the required redundancy and separation through the associated logic matrices; and the nuclear power signals to other systems were available and operating properly. e. All auxiliary equipment, such as the start-up rate channel, recorders, and indicators, operated properly. f. All instruments were properly calibrated and all setpoints and alarms were properly adjusted.
18. Radioactive waste system	To verify satisfactory flow characteristics through the equipment, to demonstrate satisfactory performance of pumps and instruments, to check for leak-tightness of piping and equipment, and to verify proper operation of monitors, alarms, and controls. More specifically, that a. All manual and automatic valves were operable. b. All instrument controllers operated to control the system at required values.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
18. Radioactive waste system (continued)	c. All alarms were operable at required locations. d. All pumps performed their design functions satisfactorily. e. All pump indicators and controls were operable at required locations. f. All waste gas compressors and blowers operated as specified. g. The gas analyzers and recombiners operated as specified. h. The waste evaporator operated as specified.
19. Sampling system	To verify that a quantity of representative fluid could be obtained safely from each sampling point. In particular, the tests were designed to verify that a. All system piping and components were properly installed. b. All remotely and manually operated valving operated in accordance with the design specifications. c. All sample containers and quick-disconnect couplings functioned properly.
20. Emergency power system	To demonstrate that the system was capable of providing power for operation of vital equipment under power failure conditions. In particular, the tests were designed to verify that a. All system components were properly installed. b. Each emergency diesel functioned according to the design intent under emergency conditions. c. The emergency units were capable of supplying the power to vital equipment as required under emergency conditions. d. All redundant features of the system functioned according to design intent.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
21. Hot functional tests	Using pump heat, the reactor coolant system was tested to check heatup and cooldown procedures to demonstrate satisfactory performance of components that were exposed to the reactor coolant temperature; to verify proper operating of instrumentation, controllers, and alarms; and to provide design operating conditions for checkout of auxiliary systems. The chemical and volume control system was tested to determine that water could be charged at rated flow against normal reactor coolant system pressure; to check letdown flow against design rate for each pressure reduction station; to determine the response of the system to changes in pressurizer level; to check procedures and components used in boric acid batching and transfer operations; to check operation of the reactor make-up control; to check operation of the excess letdown and seal-water flow path; and to verify proper operation of instrumentation controls and alarms. The sampling system was tested to determine that a specified quantity of representative fluid could be obtained safely and at design conditions from each sampling point. The component cooling system was tested to evaluate its ability to remove heat from systems containing radioactive fluid and other special equipment under varied service water conditions; to verify component cooling flow to all components; to verify that the charging pumps cooling water subsystem functioned as designed; and to verify proper operation of instrumentation, controllers, and alarms. Following this hot function test, the reactor internals were examined for evidence of vibration.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
22. Pressurizer level control system	To ensure that the system was capable of monitoring the full range of pressurizer level and to verify alarms and setpoints. Also to verify that the system, in conjunction with the chemical and volume control system, controlled pressurizer level.
23. Rod position indication system	To check the system's response to test signals and to verify correct indicating and control functions. After fuel loading and after the position indication coils were installed, a calibration check and a complete operational check were performed by operating individual control rod drive mechanisms.
24. Reactor thermocouple instrumentation	To check and calibrate the system and compare thermocouple readings with other temperature instrumentation indications up to the maximum allowable temperature.
25. Auxiliary steam generator feedwater pumps.	To verify that all pumps performed their design functions satisfactorily.
26. Primary system safety and relief valves	To verify correct relief and lift pressures as necessary.
27. Cold hydrostatic tests	To verify the integrity and leaktightness of the reactor coolant system and auxiliary primary systems with the performance of a hydrostatic test at the specified test pressure.
28. Main steam trip valves	To verify that the valves would terminate steam flow to the turbine by testing at steam temperature and pressure associated with hot functional conditions.
29. Heat tracing check	To verify operations of the circuits and controls of the heat tracing system and safety-related equipment and to obtain a set of equilibrium data under static flowing and nonflowing conditions.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
30. Pressurizer relief tank	To verify that the system responded accurately to low- and high-level and high-pressure setpoints; that the nitrogen cover gas system will maintain a nitrogen atmosphere at the required pressure; that the oxygen content of the gas space can be reduced and maintained within chemistry requirements; that the remotely operated valves for maintaining tank level operate correctly.
31. Residual heat removal system	To verify that the valve interlocks, flow controls, alarms, and indications operate properly.
32. Containment isolation valves test	To verify that the valves that provide containment isolation during accident conditions operate as designed.
33. Containment leakage test	To prepare the containment for the structural test and to provide a pre-operational containment leakage rate.
34. Containment personnel air lock and equipment hatch	To verify the leaktightness of the system.
35. CLS “Hi” and “Hi-Hi” system operation	To verify the proper operation of the systems. The test verified that all relays associated with the CLS “Hi” operated properly and that all signals were generated and all “logic” verified; the CLS “Hi-Hi” test verified the initiation of start signals to No. 2 and No. 3 EDGs and that the lockout circuitry to No. 3 EDG functioned properly.
36. Charging pump control circuit	To verify breaker interlocks, charging pump start signals, and breaker trip signals in the system.
37. Incore movable detector system	To provide an initial calibration of the upper and lower limit stop setpoints for the flux thimbles, and establish the slipping torque for the slip clutch.
38. Reactor coolant loop isolation valves	To verify that the interlocks associated with the reactor coolant isolation valves performed as designed.
39. Reactor coolant pump initial check	To verify reactor coolant pump operating valves and to establish a correlation between seal-water flow and the thermal barrier differential pressure

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.1-1 (CONTINUED)
OBJECTIVES OF SYSTEM TESTS PRIOR TO INITIAL REACTOR FUELING

System Tested	Test Objective
40. Reactor coolant system thermal expansion	To verify that all piping and components within the test boundary would expand freely and operate without interfering with other systems, components, and structures.
41. Operation from the auxiliary shutdown panel	To verify the capability of maintaining hot shutdown conditions from outside the control room at the auxiliary shutdown panel for a minimum of 4 hours.
42. Electric hydrogen recombiner	To demonstrate the performance of the electric hydrogen recombiner by running it at a set power and recording the temperatures reached and measuring the air flow through the recombiner.

13.2 FINAL STATION PREPARATION

Fuel loading began when all prerequisite system tests and operations were satisfactorily completed and the facility operating license was obtained. Upon completion of fuel loading, the reactor upper internals and pressure vessel head were installed, and additional mechanical and electrical tests were performed. The purpose of this phase of activities was to prepare the system for nuclear operation and to establish that all design requirements necessary for operation had been achieved. The core-loading and postloading tests are described below.

13.2.1 Core Loading

The overall responsibility and direction for the initial core loading was exercised by the Station Manager, assisted by the Superintendent - Station Operations.

The overall process of initial core loading was normally directed from the operating floor of the containment structure.

Standard procedures for the control of personnel and the maintenance of containment security were established prior to fuel loading.

Westinghouse provided technical advisors to assist during the initial core-loading operation.

The as-loaded core configuration was specified as part of the core design studies conducted in advance of station start-up, and as such was not subject to change at start-up.

The core was assembled in the reactor vessel, submerged in water containing enough dissolved boric acid (at least 1500 ppm boron) to maintain a core effective multiplication factor (K_{eff}) of 0.90 or lower.

The refueling cavity was dry during initial core loading.

Core moderator chemistry conditions (particularly boron concentration) were prescribed in the core-loading procedure document and were verified periodically by chemical analysis of moderator samples taken before and during core loading.

Core-loading instrumentation consisted of two permanently installed source range (pulse type) nuclear channels, two temporary incore source range channels, and a third temporary channel that could be used as a spare.

The permanent channels were monitored in the control room by licensed station operators; the temporary channels were installed in the containment structure and monitored by reactor engineering personnel.

At least one channel and one temporary channel were equipped with audible count range indicators. Both channels and both regular temporary channels displayed neutron count rates on count-rate meters and strip-chart recorders.

Minimum count rates of two counts per sec, attributable to core neutrons, were required on at least two of the four available nuclear channels at all times during core-loading operations.

Two artificial neutron sources were introduced into the core at appropriate specified points in the core-loading program to ensure a neutron population large enough for adequately monitoring the core.

Fuel assemblies, together with inserted components (control rod assemblies, burnable poison inserts, source spider, or thimble plugging devices), were placed in the reactor vessel one at a time according to a previously established and approved sequence that was developed to provide reliable core monitoring with minimum possibility of core mechanical damage.

The core-loading procedure documents included a detailed tabular check sheet that prescribed and verified the successive movements of each fuel assembly and its specified inserts from its initial position in the storage racks to its final position in the core.

Multiple checks were made of component serial numbers and types at successive transfer points to guard against possible inadvertent exchanges or substitutions of components.

An initial nucleus of eight fuel assemblies, the first of which contained an activated neutron source, was the minimum source-fuel nucleus that would permit subsequent meaningful inverse count-rate monitoring. This initial nucleus was determined by calculation and previous experience to be markedly subcritical (K_{eff} = 0.90) under the required conditions of loading.

Each subsequent fuel addition was accompanied by detailed neutron count-rate monitoring to determine that the just-loaded fuel assembly had not excessively increased the count rate and that the extrapolated inverse count-rate ratio was not decreasing for unexplained reasons.

The results of each loading step were evaluated by Vepco before the next prescribed step was started.

Criteria for safe loading required that loading operations stop immediately if:

1. The neutron count rates on all responding nuclear channels doubled during any single loading step after the initial nucleus of eight fuel assemblies had been loaded.
2. The neutron count rate on any individual nuclear channel increased by a factor of five during any single loading step.

An alarm in the containment and main control room was coupled to the source range channels with a setpoint at five times the current count rate. This alarm would have automatically alerted the loading operation to an indication of high count rate and would have required an immediate stop of all operations until the incident was evaluated by Vepco and by technical advisors.

If the licensed station operation in the control room had determined that an unacceptable increase in count rate was being observed in any or all responding nuclear channels, he would have executed one or a combination of the prepared special procedures that involved withdrawing fuel from the core, manually actuating the containment evacuation alarm, or charging concentrated boric acid into the moderator. In actuality, no difficulties were encountered on either Unit 1 or Unit 2, and core loading was satisfactorily completed in accordance with applicable procedures.

Core-loading procedures specified alignment of fluid systems to prevent inadvertent dilution of the reactor coolant, restricted the movement of fuel to preclude the possibility of mechanical damage, prescribed the conditions under which loading could proceed, identified chains of responsibility and authority, and provided for continuous and complete fuel and core component accountability.

13.2.2 Postloading Tests

Upon completion of core loading, the reactor upper internals and the pressure vessel head were installed and additional mechanical and electrical tests were performed prior to initial criticality.

The final hydrostatic tests were conducted after filling and venting were completed.

Mechanical and electrical tests were performed on the control rod drive mechanisms under both cold and hot conditions. These tests included a complete operational checkout of the mechanisms.

Checks were made to ensure that the control rod assembly position indicator coil stacks were connected to their position indicators. Similar checks were made on control rod drive mechanism coils.

Tests were performed on the reactor trip circuits to test manual trip operation, and actual control rod assembly drop times were measured for each control rod assembly.

By use of dummy signals, the reactor control and protection system was made to produce trip signals for the various unit abnormalities that required tripping.

At all times that the control rod drive mechanisms were being tested, the boron concentration in the coolant-moderator was large enough (approximately 1500 ppm boron) that criticality could not be achieved with all control rod assemblies out.

Furthermore, the number of control rod assemblies operated at any one time was restricted to no more than approximately half the total number of assemblies.

A complete functional electrical and mechanical check was made of the incore nuclear flux mapping system at the operating temperature and pressure.

Intentionally Blank

13.3 INITIAL TESTING IN THE OPERATING REACTOR

After satisfactory completion of fuel loading and final station tests, nuclear operation of the reactor was begun. The final phase of start-up and testing included initial criticality, initial unit verification testing, zero power testing, and power level escalation. The purpose of these tests was to establish the operational characteristics of the unit and core, to verify design predictions, to demonstrate that license requirements had been met, and to ensure that the next prescribed step in the test sequence could be safely undertaken. A brief description of the testing is presented in the following sections. Table 13.3-1 summarizes the tests that were performed from the initial core loading to rated power.

13.3.1 Initial Criticality

Initial criticality was established by sequentially withdrawing the shutdown and control groups of control rod assemblies from the core, leaving the last withdrawn control group inserted far enough in the core to provide effective control when criticality was achieved, and then slowly and continuously diluting the heavily borated reactor coolant until the chain reaction was self-sustaining.

Successive stages of control rod assembly group withdrawal and of boron concentration reduction were monitored by observing changes in neutron count rate, as indicated by the regular source range nuclear instrumentation, as functions of control rod assembly group position and, subsequently, of primary-water addition to the reactor coolant system during dilution.

Primary safety reliance was based on inverse count-rate ratio monitoring as an indication of the nearness and rate of approach to criticality of the core during control rod assembly group withdrawal and during reactor coolant boron dilution. The rate of approach was reduced as the reactor approached extrapolated criticality to ensure that effective control was maintained at all times.

Written procedures specified alignment of fluid systems to allow controlled start and stop and adjustment of the rate at which the approach to criticality could proceed, indicated values of core conditions under which criticality was expected, specified allowed deviations in expected values, and identified chains of responsibility and authority during reactor operations.

13.3.2 Initial Unit Verification Tests

Upon establishment of criticality, a series of tests was initiated to determine the overall unit behavior and to check out the system under operating conditions. The initial tests consisted of selected zero-power physics measurements and power escalation tests to ensure safe reactor operation while performing the overall unit checkout.

The selected zero-power measurements were made at or near operating temperature and pressure, and consisted of measurements of control rod assembly group reactivity worth, boron concentration reactivity worth, isothermal temperature coefficient, and the boron concentration and power distribution with all control rod assemblies out. Concurrent tests were conducted on the unit instrumentation, including the source and intermediate range nuclear channels. Control rod assembly operation and the behavior of the associated control and indicating circuits were demonstrated under zero-power operating conditions. The results of these tests and measurements were compared to the expected design behavior and the results were reported for each unit as an appendix to each start-up test report (References 1 & 2). The remainder of the initial station verification tests were performed during power escalation to no more than 40% of full power.

The purpose of the above nuclear tests was to survey overall station performance and to determine the adequacy of the design and the integrity of the systems used.

Detailed procedures specified the sequence of tests and measurements conducted and the conditions under which each was performed. If deviations from design predictions had existed or if apparent anomalies had developed, the testing would have been suspended and, prior to resumption of testing, the situation would have been reviewed by Vepco to determine whether a question of safety was involved. In actuality, no difficulties were encountered on either Unit 1 or Unit 2, and initial unit verification was satisfactorily completed in accordance with applicable procedures.

13.3.3 Zero-Power Testing

A prescribed program of reactor physics measurements was undertaken to verify that the basic static and kinetic characteristics of the core were as expected and that the values of the kinetic coefficients assumed in the safeguards analysis were indeed conservative.

The measurements were made at zero power and primarily at or near operating temperature and pressure. The measurements included verification of calculated values of control rod assembly group and unit reactivity worths, of isothermal temperature coefficient under various core conditions, of differential boron concentration reactivity worth, and of critical boron concentrations as functions of control rod assembly group configuration. Relative power distribution checks were made in normal and abnormal control rod assembly configurations.

Detailed procedures were prepared to specify the sequence of tests and measurements to be conducted and the conditions under which each was to be performed to ensure both safety of operation and the relevance and consistency of the results obtained.

13.3.4 Power Level Escalation

When the operating characteristics of the reactor and unit were verified by the preliminary zero-power tests, a program of power level escalation in successive stages brought the unit to its full rated power level. Both reactor and unit operational characteristics were closely examined at each stage and the relevance of the safeguards analysis was verified before escalation to the next programmed level was effected.

Reactor physics measurements were made to determine the magnitudes of reactivity effects, of control rod assembly group differential reactivity effects, of control rod assembly group differential reactivity worth, and of relative power distribution in the core as functions of power level and control rod assembly group position.

Concurrent determinations of primary and secondary heat balances ensured that the several indications of power level were consistent and provided bases for calibration of the power range nuclear channels. The ability of the reactor control and protection system to respond effectively to signals from primary and secondary instrumentation under a variety of conditions encountered in normal operations was verified.

At prescribed power levels the response characteristics of the reactor coolant and steam systems to dynamic stimuli were evaluated. The responses of system components were measured for 10% loss of load and recovery, 50% loss of load and recovery, turbine trip, and the trip of a single control rod assembly.

After the rated power level was achieved, a series of load follow tests was performed at selected power level escalation steps. The results of these tests gave actual reactor and unit behavior under operating conditions and were used to verify predicted load-follow capabilities.

Adequacy of radiation shielding was verified by gamma and neutron radiation surveys inside the containment and the outside area immediately adjacent to the containment.

The sequence of tests, measurements, and intervening operations was prescribed in the power escalation procedures, together with specific details relating to the conduct of the several tests and measurements. The measurement and test operations during power escalation were similar to normal operations.

13.3.5 Poststart-Up Surveillance and Testing Requirements

Poststart-up surveillance and testing requirements are designed to provide assurance that essential systems, including equipment components and instrument channels, are always capable of functioning in accordance with their original design criteria. These requirements can be separated into two categories:

1. The system must be capable of performing its function, i.e., pumps deliver at design flow and head, and instrument channels respond to initiating signals within design calibration and time responses.
2. Reliability is maintained at levels comparable to those established in the design criteria and during early station life.

The testing requirements, as described in the Technical Specifications, establishing this reliability and, in addition, provide the means by which this reliability is continually reconfirmed. Verification of operation of complete systems is checked at refueling intervals. Individual checks of components and instrumentation are made at more frequent intervals, as outlined in the Technical Specifications.

The techniques used for the testing of instrument channels included a preoperational calibration that confirmed values obtained during factory test programs. These reconfirmed calibration values became the reference for recalibration maintenance at refueling intervals during station life. Periodic testing, as defined in the Technical Specifications, includes the insertion of a predetermined signal that will trip the channel bi-stable. Indication of the operation is confirmed and recorded.

Testing of components is initiated through manual actuation. If response times are important, they are measured and recorded. The capability to deliver design output is checked by instrumentation and compared against design data. Allowable discrepancies are established in the Technical Specifications. The component is operated sufficiently long to allow the equalization of operating temperatures in bearings, seals, and motors. Checks are made on these parameters. The component is surveyed for excessive vibration. Readings are recorded.

It is believed that testing in accordance with the above described program provides a realistic basis for determining maintenance requirements, and, as such, ensures continued system capabilities, including reliability equal to that established in the original criteria.

13.3 REFERENCES

1. Virginia Electric and Power Company, *Unit No. 1 Start-Up Test Report*, Docket No. 50-280, May 1, 1973.
2. Virginia Electric and Power Company, *Unit No. 2 Start-Up Test Report*, Docket No. 50-281, July 31, 1973.

Table 13.3-1
INITIAL TESTING SUMMARY

Tests	Conditions	Objectives	Acceptance Criteria
Control rod assembly drop tests	a. Cold shutdown b. Hot shutdown	To measure the drop time of control rod assemblies under full-flow and no-flow conditions	Drop time less than value in Technical Specifications
Thermocouple/ RTD inter-calibration	Various temperatures during system heatup at zero power	To determine in-place isothermal correction constants for all core exit thermocouples and reactor coolant RTDs	Sensors showing excessive deviations from average were removed from service or replaced
Nuclear design check tests	All two-dimensional control rod assembly group configurations at hot zero power	To verify that nuclear design predictions for endpoint boron concentrations, isothermal temperature coefficients, and power distributions were valid	Within limits established in FSAR for $\delta\rho/\Delta T$ and $F_{\Delta H}$
Control rod assembly group worth	All control rod assembly groups at hot zero power	To verify that nuclear design predictions for control rod assembly group differential worths with and without partial length control rod assemblies were valid	Within limits established in FSAR for $\Delta p/\Delta h$, p/h, $\delta/\Delta h$, and $\Delta p/h$
Power and Doppler coefficient measurement	0 to 92% of rated power	To verify that nuclear design predictions for differential power coefficients and Doppler reactivity coefficients were valid	Technical Specification limiting values
Power and Doppler reactivity defects	0 to 92% of rated power	To verify that nuclear design predictions for power and Doppler reactivity defects were valid	Technical Specifications limiting values

Table 13.3-1 (CONTINUED)
INITIAL TESTING SUMMARY

Tests	Conditions	Objectives	Acceptance Criteria
Automatic control system	Approximately 30% of rated power	To verify control system response characteristics for: 1) Steam generator level control system 2) Control rod assembly automatic control system 3) Turbine control system	Applicable FSAR criteria
Load swing test	10% steps at 35, 75, and 100% of rated power	To verify reactor control performance	Applicable unit performance criteria
Station trip	Full-load rejection from 50 and 100% of rated power	To verify reactor control performance	Applicable unit performance criteria
Pressurizer spray effectiveness test	Hot shutdown	To verify that pressurizer pressure is reduced at the required rate by pressurizer spray actuation	Applicable unit performance criteria
Minimum shutdown verification	Hot zero power	To verify the nuclear design prediction of the minimum shutdown boron concentration with one stuck control rod assembly	Stuck control rod assembly shutdown criteria
Static rod insertion and rods-out-of-position test	50% of rated power	To verify that a single control rod assembly inserted fully or part-way below the control bank is detected by ex-core nuclear instrumentation, core exit thermocouples under typical operating conditions, and to provide bases for adjustment of protection system setpoints	Inserted control rod assembly detectable with station instrumentation

Table 13.3-1 (CONTINUED)
INITIAL TESTING SUMMARY

Tests	Conditions	Objectives	Acceptance Criteria
Step load reduction test	Reduction from 75% to 25% of rated power Reduction from 100% to 50% of rated power	To verify operation of reactor control system	Applicable unit performance report criteria
Dynamic control rod assembly drop test	45% of rated power	To verify automatic detection of dropped control rod stop and turbine cutback	Required power reduction and control rod assembly withdrawal block accomplishment
Turbine-generator start-up tests	Pre- and postsynchronization	To verify that the turbine-generator unit and associated controls and trips were in good working order and ready for service	Successful completion of all mechanical, electrical, and control functional checks
Turbine generator	0 to 75% of rated power	To verify normal trouble-free performance of the turbine generator at low power	Performance within manufacturer's limitations
Acceptance run	100 hr at rated power	To verify reliable steady-state full-power capability	100 hr equilibrium operation at full power
Station blackout test (loss of offsite power only)	Unit 1: 10% of rated power Unit 2: 37% of rated power	To verify the ability of the station control and protection systems to bring the plant safely to the hot shutdown condition following the loss of power to the 4160-V emergency buses	Emergency diesel generators start and restore power to emergency buses; both reactor and turbine are tripped; relays and breakers respond properly to de-energize the emergency buses on under-voltage and re-energize them from the diesel generators

Table 13.3-1 (CONTINUED)
INITIAL TESTING SUMMARY

Tests	Conditions	Objectives	Acceptance Criteria
Steam generator moisture carryover	Unit 1: 90%/100% of rated power Unit 2: 90, 95, and 100% of rated power	To verify that moisture carryover (averaged over all three steam generators) is less than 0.25%	Less than 0.25% moisture carryover (averaged over all three steam generators)
Rod drive mechanism stepping test	a. Cold shutdown b. Hot shutdown	To verify that each individual rod could be properly stepped from one position to another	Rod speeds and movement within Technical Specification limits
Part-length rod mechanism brake test	Shutdown	To ensure engagement of brake mechanism on application of current	Smooth operation of the engagement and disengagement of the part-length rod brake mechanism
Rod control system	Shutdown	To verify that the full-length rod control system performed properly	Smooth operation with rod position indicators and step counters verifying proper rod motion when in both “bank select” and “manual” mode of operation
Reactor coolant system flow measurement	Shutdown	To verify that the actual flow rates were equal to or greater than design flow rates	Applicable flow rate criteria
RTD bypass loop flow verification	Hot shutdown	To verify adequate flows through the RTD bypass loops	Applicable flow rate criteria
Containment shielding test	Hot zero power, 30, 50, 75, and 92%	Obtain actual radiation levels at specified locations and power levels	Levels are within design criteria

Table 13.3-1 (CONTINUED)
INITIAL TESTING SUMMARY

Tests	Conditions	Objectives	Acceptance Criteria
Ex-core detector behavior	Various power levels	To develop curves of incore/ex-core axial offsets for each ex-core detector and to develop plots of the sum of top and bottom detector currents versus power and full-power normalized detector currents versus axial offset	Within design specifications
Overpower and overtemperature delta T calibration	Hot shutdown, start-up, 75 and 92%	To ensure protection against excessive power levels and to protect the core against DNB	System calibrated to Technical Specifications
Delta flux calibration	Shutdown	To calibrate the reactor core power axial offset contribution to overpower and overtemperature delta T setpoints	Set to Technical Specification limits
Static rod drop measurement	48% power	To determine effect of the dropping of a full-length control rod assembly on the hot-channel factors	Within design limits
Rod ejection measurements	Hot, zero power, 32% Unit 1, 50% Unit 2	To confirm that the control rod insertion limits are satisfactory	Within design limits
Power distribution measurements	Hot, zero power, 75%	To obtain the core power distribution and flux maps	Within design criteria
Flow coastdown	Hot shutdown	To obtain reactor coolant flow coastdown rates	Within limits specified in FSAR
Nuclear design check	Hot shutdown	Determine differential and integral worth of the controlling RCC bank and differential boron worth over the range of controlling RCC bank	Applicable design criteria

Intentionally Blank

13.4 OPERATING RESTRICTIONS

13.4.1 Safety Precautions

The measurements and test operations during zero power and power escalation were similar to normal station operations at power, so that normal safety precautions were adequate.

13.4.2 Initial Operation Responsibilities

Vepco had overall responsibility for supervising and directing all phases of testing. Technical responsibility for each individual phase of actual start-up resided with the functional group most directly concerned with the results of the phase. Stone & Webster and Westinghouse had onsite representatives of supporting functional groups to provide technical advice, provide recommendations and assistance in planning, and execute the respective phases of unit start-up. Specific responsibilities during each phase of testing are discussed in preceding sections.

All system operations in the testing program were performed by station operators in accordance with the approved written procedures. These procedures included such items as the delineation of administrative procedures and test responsibilities, equipment clearance procedures, test purpose, conditions, precautions, limitations, and sequence of operations.

The methodology used in the preparation, review, approval, and revision of initial operating procedures is briefly described below.

The initial draft of each operating procedure was written by a member of the station staff knowledgeable in the operation of the system under consideration. After review by the Superintendent - Station Operations, the Operating Supervisor, or the Supervisor - Engineering Services, the procedure was submitted to the Station Nuclear Safety and Operating Committee for review and approval. The purpose of this was to ensure that the procedure was in accordance with other established procedures, clear in content, met the design criteria specified, and met the safety requirements for sound operating practices. If a procedure was found to be unsatisfactory by the committee, the necessary correction was made by the individual(s) originally preparing the procedure wherever possible, to provide continuity. All procedures approved by the committee were signed and dated by the committee chairman before implementation by the Operating Department.

Any minor procedural change found necessary after initial committee approval was obtained was to be forwarded through the Operating Supervisor and Superintendent - Station Operations for comment. Further review and approval was to be obtained from the Station Manager before the minor procedural change was implemented.

Any significant change was to be handled in the same manner as the approval required for the initial operating procedure.

Test procedures stating the test purpose, conditions, precautions, limitations, and criteria for acceptance were prepared for each test by station personnel with assistance from Westinghouse and Stone & Webster technical advisors. Before implementation, all such procedures were reviewed and approved by Vepco's senior personnel in accordance with approved standard administrative procedures.

As part of the precautions, all licensed senior reactor operators and manufacturer's representatives whose equipment was being tested were instructed to stop a test or a portion of a test if the test was not being performed safely or in accordance with the written test procedure. The test procedure was reviewed and approved by the Station Manager or his representative. If substantial revision was required, however, the Station Manager reviewed the change, using the same approach as that used for a new test procedure, before approving continuation.

If the results of preoperational tests, fuel loading, post-fuel-loading tests, or initial operation indicated that system modifications and/or procedural changes were required, the proposed changes were discussed with the Vepco engineering staff at the General Office in Richmond, Virginia. The station staff normally made recommendations or offered solutions before this time, and these accompanied the request for the change as an Engineering Deficiency Report.

Any changes that could alter the operation of the station were to be handled under the following three categories:

1. Changes not affecting the approved design or operation of the station, but considered primarily for convenience or improvement to operations, could be handled at the station level with the approval of the Station Manager. A report of all such changes was to be forwarded to the Superintendent - Production Operations and the Supervisor - Nuclear Design.
2. Changes that could alter the arrangement or function of a system from the intended approved design were to be reviewed by the Station Nuclear Safety Committee. If approved by the committee, the recommendation was forwarded to the System Nuclear Safety Committee for final approval. If there was no requirement to amend the FSAR, the proposed change was implemented through the Director of Power Station Design.
3. Design changes that would incorporate changes to approved design prints and would affect the operation of the station as described in the FSAR, either by description or drawings, were to be approved by the Station Nuclear Safety Committee and the System Nuclear Safety Committee. The recommended change was forwarded to the Manager of Power Production and the Vice President - Power, respectively. If approved, the Vice President - Power informed the Atomic Energy Commission (AEC) of the requested change. When changes of this type were considered, a full review of the Technical Specifications was conducted, and appropriate approved changes were handled as above through amendments to the Technical Specifications.

Vepco had overall responsibility during plant start-up, including precriticality tests, approach to criticality, and postcriticality operation. The station staff was assisted by the supplier of the nuclear steam supply system, Westinghouse Electric Corporation. Experienced Westinghouse reactor engineers were assigned to the station from fuel loading, through power ascension, until completion of the 100-hr full-load test. These reactor engineers had previously participated in reactor start-ups of similar units and were qualified and knowledgeable in reactor operations. At least one reactor engineer was at the site during all shifts when the reactor was operating. The responsible shift reactor engineer reported directly to the Shift Supervisor and received instructions from him. The reactor engineer acted in an advisory capacity only; Vepco retained responsibility and control of the unit. Reactor specialists (e.g., control engineers) were available and utilized as required.

The results of preoperational and start-up testing were reported to the Atomic Energy Commission in reports dated May 1, 1973 (Unit 1 Start-up Test Report), July 31, 1973 (Unit 2 Start-up Test Report), and July 1, 1976 (Supplement to Surry Units 1 and 2 Start-up Reports).

Intentionally Blank

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

13.5 STEAM GENERATOR POSTREPAIR START-UP TEST PROGRAM

An extensive steam generator repair program was completed in 1979 for Surry Unit 2 and in 1981 for Surry Unit 1. In both cases, a postrepair integrated start-up test program was performed as described below. Refer to Section 10.3.1 for further details on the steam generator repair program.

The subject test program consisted of three phases: construction tests, preoperational tests, and start-up tests. The format of the program followed the intent of Regulatory Guide 1.68, Revision 2 (Reference 1).

The tests in the construction test phase were designed to provide assurance that the construction and installation of new, modified, or replaced equipment in the station were accomplished properly and in accordance with requirements.

The tests in the preoperational test phase were designed to provide assurance that the components and subsystems of new, modified, and original systems function safely within established design criteria. The preoperational tests on new or modified systems were conducted after the successful completion of construction tests and before fuel loading. This test phase also allowed the plant operating staff to become familiar with the operation of a new or modified system and to verify by trial use, to the extent practical, that the operating procedures were adequate.

The tests in the start-up test phase were designed to provide assurance that systems previously demonstrated as functioning safely, and new or modified systems, will function to (1) provide for safe normal operation and high tolerance for system malfunctions and transients; (2) ensure that, in the event of errors, malfunctions, and abnormal conditions, the reactor protection systems and other design features will arrest the event or limit its consequences to defined and acceptable levels; and (3) ensure that adequate safety margins exist for events of extremely low probability or for arbitrarily postulated hypothetical events without substantial reduction in the safety margin for the protection of public health and safety. The start-up tests were performed during and after fuel loading to confirm the design basis and demonstrate that the plant will continue to operate in accordance with design.

Per Criterion 1 of Appendix A to 10 CFR 50, all structures, systems, and components were tested or demonstrated operable to levels commensurate with the importance of their safety function. In addition, the extent of testing varied directly with the amount of construction done to and around the particular equipment or system. The sequence of tests was conducted so that the safety of the plant was never totally dependent on the performance of untested structures, systems, or components.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

13.5.1 Test Phases

Each phase of the integrated start-up test program was composed of a series of tests, as described below.

13.5.1.1 **Construction Test Phase**

The construction test phase consisted of nondynamic instrument, electrical, and mechanical tests included in design change packages for new or modified systems or components.

The installed components and systems were tested and evaluated according to approved design change test procedures. Construction tests were performed to ensure the quality implementation of the design change.

This phase also included the testing of any rework associated with deficiencies found by testing or quality control in the construction test, preoperational test, or start-up test phases.

All safety-related equipment or systems removed for maintenance work underwent instrument, electrical, and mechanical tests included in the maintenance procedure, as applicable. All maintenance tests were conducted by station personnel.

13.5.1.2 **Preoperational Test Phase**

The preoperational test phase consisted of functional tests on new, modified, and affected original equipment and systems. This phase included tests, adjustments, calibrations, and system operations necessary to ensure that the subsequent testing would be safely undertaken. This phase also included a walkdown of systems adjacent to construction work. Any repairs and subsequent testing of equipment were accomplished by a field change to the design change.

Preoperational tests are listed in Table 13.5-1. The actual sequence of individual tests was formulated before the performance of the tests, considering equipment and system availability, and was maintained on an integrated start-up test schedule.

In instances where the performance of components or systems deviated from predicted results, further engineering evaluations, rework, and/or retesting were performed to resolve the discrepancies before the test was considered satisfactory. Systems that had to be modified as a result of the preoperational tests were retested to verify acceptable performance. Components and systems were tested and evaluated according to approved testing procedures. Preoperational tests were performed to verify as nearly as possible the performance of the system under actual operating conditions. Where required, simulated signals or inputs were used to verify the full operating range of the system and to calibrate and align the systems and instruments at these conditions.

13.5.1.3 **Start-Up Test Phase**

The major testing milestones during the start-up test phase are identified and discussed below. Major start-up tests are listed in Table 13.5-2.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

13.5.1.3.1 Post-Fuel-Loading Tests

Systems that are not used during normal plant operation but must be in a state of readiness to perform safety functions were tested or demonstrated operable before plant conditions required them to be available, as defined in the Technical Specifications. Abnormal unit conditions were simulated during testing as required and when such conditions did not endanger personnel or equipment, or contaminate systems whose cleanliness had been established. Fuel loading began when all prerequisite system tests and operations were satisfactorily completed. Upon completion of fuel loading, the reactor upper internals and pressure vessel head were installed. Additional mechanical and electrical tests were performed on the rod control system, rod position indication system, and incore movable detection system. The purpose of this segment of the start-up test phase was to prepare the system for nuclear operation and to establish that all design requirements necessary for operation were achieved.

13.5.1.3.2 Hot Functional Tests

Before initial criticality, the following hot functional tests were performed: heatup of the primary system, thermal expansion testing of affected systems, vibration testing of construction-affected equipment, reactor coolant pump coastdown time check, and steam generator water-hammer testing (auxiliary feed). The final pressure test was conducted in accordance with the Technical Specifications.

13.5.1.3.3 Criticality and Low-Power Physics Tests

On completion of hot functional tests, nuclear operation of the reactor was begun. These final segments of start-up testing included criticality and low-power physics testing. The purpose of these tests was to verify the operational characteristics of the unit and core, to acquire data for the proper calibration of setpoints, and to ensure that operation was within license requirements. The actual sequence of tests was formulated by station engineering and operating personnel, considering test requirements and equipment availability.

Procedures were prepared to specify the sequence of tests and measurements conducted and the conditions under which each was to be performed to ensure safety of operation and consistency of the results obtained. If significant deviations from design calculations existed, or if unacceptable behavior was revealed, or if apparent anomalies developed, the testing was suspended and the situation was reviewed to determine whether a question of safety was involved before the resumption of testing.

13.5.1.3.4 Power Level Escalation Testing

When the operating characteristics of the reactor and unit were verified by low-power physics testing, a program of power level escalation in successive stages was used to bring the unit to its full rated power level. Both reactor and unit operational characteristics were examined at each stage of the power escalation program.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

13.5.1.3.5 At-Power Testing

On completion of power level escalation testing, the following at-power tests were performed: final steam generator carryover testing, final recirculation ratio testing, secondary plant heat balance determination, condensate-polishing chemistry performance testing, and load rejection testing with the condensate polisher.

13.5.2 Extent of Testing

Because of the various amounts of construction done to and around each system, a graded approach for the extent of testing was employed. The tests required for individual components within a system were developed by the Start-up Group and listed on a test matrix for that system.

In areas such as containment, where extensive work had been performed, all equipment and systems were checked during the construction testing, preoperational testing, or start-up testing phase. In areas such as the auxiliary building, where little work had been performed, selected system walkdowns were employed in conjunction with normal station start-up procedures to verify the operability of the equipment.

Systems that were new or had undergone major design-basis changes were subjected to complete component testing and performance testing to verify design and installation.

13.5 REFERENCES

1. U.S. Nuclear Regulatory Commission, *Preoperational and Initial Start-up Test Programs for Water-Cooled Power Reactors*, Regulatory Guide 1.68, Revision 2, August 1978.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-1

POST-STEAM-GENERATOR REPAIR, LIST OF PREOPERATIONAL TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
	I. PLANT INSTRUMENTATION	
1. Nuclear instrumentation	Before core loading	Nuclear instruments were aligned and source range detector response to a neutron source checked as the primary source was loaded.
2. Process instrumentation	Ambient and/or at temperature	Required equipment was aligned per station procedures.
	II. REACTOR COOLANT SYSTEM	
1. Pressure boundary integrity		
a. Hydrostatic test	Below 200°F (after verification of cleanliness and fill of system)	Cold hydrostatic testing of each reactor coolant system loop was performed at test pressures as specified by ASME standards for the system. Before pressurization, the affected portions of the system were heated above the minimum temperature for pressurization. The pressure was then increased in increments, and at each increment inspections were made for leakage. Leaky valves or mechanical joints were not a basis for rejecting the test. Overpressure protection was provided during testing.
b. Baseline data for inservice inspection	During preoperational testing	Systems and components that require inspection in accordance with Section XI of the ASME Code were examined for baseline data. Data from these inspections provide baseline data for subsequent inservice inspections.
2. Component tests		
a. Pressurizer safety valve	Ambient pressure	The setpoints of the safety valves were verified using existing station procedures.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-1 (CONTINUED)

POST-STEAM-GENERATOR REPAIR, LIST OF PREOPERATIONAL TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
	III. REACTIVITY CONTROL SYSTEM	
1. Automatic reactor power control test systems	Preoperational testing	The system alignment was verified at pre-operational operational conditions to demonstrate response of the system to simulated inputs. These tests were performed to verify that the systems would operate satisfactorily at power.
	IV. REACTOR PROTECTION SYSTEMS	
1. Reactor protection system	Before core loading	Before core loading, the reactor protection system was tested to demonstrate operability, proper logic, redundancy, and coincidence. The protection channels were verified through to tripping of the reactor trip breakers.
2. Engineered safety features	Before core loading	Before core loading, the engineered safety features logic systems were tested to demonstrate operability, proper logic, redundancy, and coincidence.
	V. POWER CONVERSION SYSTEM	
	Done under startup testing	

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-1 (CONTINUED)

POST-STEAM-GENERATOR REPAIR, LIST OF PREOPERATIONAL TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
	VI. AUXILIARY SYSTEMS	
1. Residual heat removal system	Before core loading	This system was tested by verifying pressure and flow characteristics of the pumps and operation of the isolation valves.
2. Containment instrument air system	Before core loading	The instrument air system, including air receivers and compressors, was tested to verify proper operation.
3. Neutron shield tank cooling system	Before core loading	The system was operationally checked out to verify heat-exchanger operability.
4. Leak detection system	Before and during pre-operational tests	Temperature detectors in the drain lines from pressurizer safety valves and the reactor vessel head seal and their alarm functions were checked. Pressurizer relief tank level and temperature sensors were calibrated, and the associated alarms were checked.
	VII. ELECTRICAL SYSTEM	
1. Emergency power systems	Before core loading	The automatic starting and loading of the diesel generators was demonstrated under loss of emergency bus ac power.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-1 (CONTINUED)

POST-STEAM-GENERATOR REPAIR, LIST OF PREOPERATIONAL TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
	VIII. CONTAINMENT SYSTEMS	
1. Reactor containment	Before core loading	Containment type A leakage tests were performed in accordance with an NRC-approved topical report,[a] which provides for a reduced-duration test. Containment type B and C leakage tests were performed in accordance with Appendix J to 10 CFR 50.
2. Containment isolation	Before core loading	The operation of actuation systems and components used for containment isolation was verified.
	IX. GASEOUS RADIOACTIVITY REMOVAL SYSTEMS	
	Done under start-up testing	
	X. EMERGENCY CORE COOLING SYSTEM	
1. High-pressure safety injection	Before core loading	This system was operationally tested to verify pressure/flow values. Tests were also conducted to check pump operating characteristics. More specifically, the tests checked that a. Valves installed for redundant flow paths operated as designed. b. Pump operating characteristics were verified.

a. BN-TOP-l, Revision J.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-1 (CONTINUED)

POST-STEAM-GENERATOR REPAIR, LIST OF PREOPERATIONAL TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
	X. EMERGENCY CORE COOLING SYSTEM (continued)	
1. High-pressure safety injection (continued)		c. Valves and pumps operated on operator initiation and/or automatically on initiation of a safety injection signal. d. Level and pressure instruments were properly calibrated.
2. Low-pressure safety injection	Before core loading	The low-head safety injection system was checked to verify design flow, flow paths, and pump operating characteristics. More specifically, the system was checked to ensure that a. Valves installed for redundant flow paths operated as designed. b. Pump operating characteristics were verified with the reactor coolant system at ambient conditions. c. Valves and motors operated on operator initiation and/or automatically on initiation of a safety injection signal. d. Level and pressure instruments were properly calibrated. In addition a 100-hr endurance test was performed, and the pump was disassembled and inspected.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-1 (CONTINUED)

POST-STEAM-GENERATOR REPAIR, LIST OF PREOPERATIONAL TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
	XI. FUEL STORAGE AND HANDLING SYSTEM	
1. Refueling equipment (hand tools and power equipment, including protective interlocks)	Before core loading	Tests were performed before core loading to demonstrate the functioning of the fuel transfer system.
	XII. REACTOR COMPONENTS HANDLING SYSTEM	
	Done during start-up	
	XIII. RADIATION PROTECTION SYSTEM	
1. Criticality and area monitors	Before core loading	The radiation alarms associated with core loading were checked out and the alarm setpoints verified.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
I. PLANT INSTRUMENTATION		
1. Nuclear instrumentation (out of core)	Before criticality	Just before criticality, all channels were checked to verify high-level trip functions, alarm setpoints, audible count rates where applicable, operation of strip-chart recorders, and any auxiliary equipment.
2. Process instrumentation (temperature, pressure, level, and flow instruments)	Ambient and/or at temperature	Equipment was aligned per station procedures.
II. REACTOR COOLANT SYSTEM		
1. Vibration and amplitude	After fuel loading	Vibration sensors were placed on the main coolant pumps and main coolant piping in order to check for excessive vibration while starting and stopping the pumps.
2. Expansion and restraint	During plant heatup	During the heatup to operating temperature, selected points on components and piping of the reactor coolant system were checked at various temperatures to verify unrestricted expansion. Points of interference detected during the heatup were corrected before increasing the temperature.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
II. REACTOR COOLANT SYSTEM (continued)		
3. Integrated hot functional	Heatup and at-temperature hydrostatic testing has been satisfactorily completed and reactor coolant system instruments are aligned and operational. Associated auxiliary systems shall be operational to the extent required to support hot functional testing.	The reactor coolant system was tested using tests pump heat to reverify heatup procedures to demonstrate satisfactory performance of components and systems exposed to reactor coolant system temperature. Proper operation of instrumentation, controllers, and alarms was checked against design operating conditions of auxiliary systems, and setpoints were verified. Among the demonstrations performed were a. To check that water could be charged by the chemical and volume control system at rated flow against normal reactor coolant pressures. b. To check letdown design flow rate for each operating mode. c. To check response of system to a change in pressurizer level. d. To check operation of the excess letdown and seal-water flow paths. e. To check steam generator level instrumentation response to level changes.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
II. REACTOR COOLANT SYSTEM (continued)		
3. Integrated hot functional tests (continued)		f. To check thermal expansion of selected system components and piping. g. To perform isothermal calibration of resistance temperature detectors and incore thermocouples. h. To operationally check out the residual heat removal system.
4. Component tests		
a. Pressurizer	At operating temperature	During the hot functional testing, the pressure-controlling capability of the pressurizer was demonstrated to be within the controlling band. With reactor coolant pumps operating and with full spray, the pressure-reducing capability of the pressurizer was verified. With the spray secured and all heaters energized, the pressure-increasing capability of the pressurizer was verified. Pressurizer relief valves were functionally checked.
b. Reactor coolant pumps and motors	At ambient conditions and during heatup and at temperature	As the pumps and motors were placed in operation, they were checked for a. Direction of rotation (initial start only). b. Vibration. c. Power requirements. d. Lubrication. e. Cooling. f. Megger and hi-pot test (as applicable).

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
II. REACTOR COOLANT SYSTEM (continued)		
		g. Overload protection.
		h. Correct power supply voltage.
c. Steam generators	At ambient conditions and during heatup and at temperature	The proper operation of instrumentation and control systems of steam generators were checked during heatup and at temperature. The heat transfer capability of the steam generators was demonstrated. The functioning of the blowdown system was checked.
5. Pressure test of reactor coolant system	Before criticality	After core loading and installation of the reactor vessel head and torquing of the reactor vessel head studs, pressure testing was performed in accordance with Technical Specifications.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
II. REACTOR COOLANT SYSTEM (continued)		
6. Chemical tests (to establish water quality)	Before heatup during start-up test	Water for reactor coolant system fill and makeup was analyzed for chloride content, conductivity, total suspended solids, pH, clarity, and fluorides to requirements specified by the chemistry manual for the nuclear steam supply system. After core loading and before exceeding 250°F, hydrazine was added to scavenge oxygen before critical operation. Before criticality, at criticality, and during power escalation, chemical analysis was performed to verify requirements.
7. Reactor coolant flow test	Before criticality	After core loading, measurements were made of elbow tap differential pressures to make a relative comparison. At hot shutdown conditions after core loading, measurements of loop elbow differential pressure drops were made. Using these data with the reactor coolant pump performance curve, the calculated flow was verified to the design flow. Flow coastdown and transients after reactor coolant pump stoppages were also determined at shutdown conditions after core loading.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
III. REACTIVITY CONTROL SYSTEMS		
1. Chemical and volume control system	At ambient and/or at operating conditions; system components are operationally checked out	Makeup and letdown operations were conducted with the chemical and volume control system to check out the different modes of dilution and boration and to verify flows in the different modes. The adequacy of heat tracing to maintain the required boric acid concentration in solution was verified. The ability to adequately sample was demonstrated.
2. Emergency boration system	During hot functional testing	The pressure/ flow characteristics of the emergency boration system were verified by pumping into the reactor coolant system.
3. Incore monitor system		
a. Incore thermocouples	During heatup and at temperature	During heatup and at temperature, the incore thermocouples were calibrated to the average of the reactor coolant system resistance temperature detectors. All readout and temperature-compensating equipment was checked during the calibration, and isothermal corrections for the operative thermocouples were determined.
b. Movable detector system	At ambient conditions after core loading and critical testing	After core loading, the installation checkout of the movable detector system was completed.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
III. REACTIVITY CONTROL SYSTEMS (continued)		
4. Control rod system		
a. Rod control system	Ambient conditions after core loading and critical testing	During the installation check of this system, it was energized and operationally checked out with mechanisms connected to each power supply. The ability of the system to stop the mechanism was verified, the alarm and inhibit functions were checked out, and the values of system parameters were adjusted to specified values. After core loading, the operation of each rod over its full range of travel was demonstrated.
b. Rod drop	Cold and hot plant conditions after core loading	At cold and hot plant conditions after core loading, the drop times of the full-length rods were measured. The drop time is measured from the release of the rod until the rod enters the top of the dashpot. This time was verified to be less than the maximum value specified in the Technical Specifications.
c. Rod position indication	At ambient conditions and at temperature after core loading	During rod control system tests, the position indication system was aligned to provide rod movement indication. Rod bottom setpoints were adjusted during these tests. After plant heatup, individual rod positions were calibrated to within tolerances specified by the test procedure.
IV. REACTOR PROTECTION SYSTEM		
	Done during preoperational testing	

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
V. POWER CONVERSION SYSTEM		
1. System tests		
a. Vibration frequency and amplitude	Hot functional testing and/or plant heatup after criticality	When the main turbine was rolled, vibration readings were monitored. (Turbine vibrations were also monitored throughout the power escalation program.) Major equipment (e.g., feedwater pumps and condensate pumps) was operated as it became available and was observed for indications of excessive vibration.
b. Expansion and restraint	During heatup and at temperature	During heatup to operating temperature, selected points on the components and piping of the systems were checked at various temperatures to verify that they could expand unrestricted.
2. Components and individual systems		
a. Steam generator pressure relief and safety valves	Pressure conditions	The setpoint of safety valves was verified by in-plant tests at pressure and temperature conditions when the unit was shut down. Setpoints were checked by using a pressure-assist device that adds to the force due to pressure. Once the valve left the seated position, the assist device was vented, allowing the valve to reset immediately. Steam relief valve setpoints were checked during instrument alignment.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
V. POWER CONVERSION SYSTEM (continued)		
2. Components and individual systems (continued)		
b. Auxiliary feedwater system	Before criticality	During hot functional testing before criticality, the auxiliary feedwater system was checked out to verify its ability to feed the steam generators. Automatic starting was checked during the safeguards logic system tests.
c. Turbine control and bypass valve	Hot functional testing and/or power operation after criticality	During hot functional testing, the turbine control system was demonstrated by turbine operation up to and including a period of operation at synchronous speed. The turbine bypass valves to the condenser and their associated control systems were operationally checked out during hot functional testing.
d. Feedwater and feedwater control system	Hot functional testing and at power	The feedwater and condensate pumps were operationally checked out during hot functional testing. During power escalation the power was increased and the ability of the feedwater pumps and control system to maintain level in the steam generators was verified.
e. Condenser circulating water	Before hot functional testing	Before hot functional testing, the main circulating water system valves were tested to verify operability.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
V. POWER CONVERSION SYSTEM (continued)		
2. Components and individual systems (continued)		
f. Makeup water and chemical treatment system	During steam generator fill, hot functional testing, and start-up testing	The makeup system to the system generators was checked out during hot functional testing and at power. The chemical treatment system was checked out when chemicals were added to the steam generators at heatup to steaming conditions.
VI. AUXILIARY SYSTEMS		
1. Reactor coolant system makeup test (CVCS)		See Section III, Item 1.
2. Seal and pump cooling water test (CVCS)	Before heatup and at temperature	Before reactor coolant pump operation and with the system pressurized, flow to the pump seals and cooling water was set, and flow was adjusted to specified values using installed instruments. During hot functional testing when at operating temperature and pressure, seals and cooling flows and temperatures were checked.
3. Secondary vent and drain system	During hot functional testing	During hot functional testing after core loading, the secondary system was vented while pressurizing the secondary system. Secondary drains were tested for unrestricted flow in accordance with operating procedures.
4. Component cooling system	Ambient and/or hot plant conditions	Component cooling flow to the various components in the affected systems was adjusted, the system operationally checked out, and setpoints verified.
5. Residual heat removal system	Before and during hot functional testing	Heat removal capability was demonstrated.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
VI. AUXILIARY SYSTEMS (continued)		
6. Service water system	Before hot functional testing	The system was operationally checked out to verify pressure and flow. Service water flow to components in the system was verified.
7. Control rod drive mechanism and rod position indication coil cooling system	Before and/or during hot functional testing	The system was operationally checked out to verify air flow, temperatures, and motor current.
8. Primary sampling system	Before and/or during hot functional testing	Operations were performed to a. Demonstrate that liquid and gas samples could be obtained from sample points. b. Demonstrate that valves, instruments, and controls functioned properly. c. Verify proper functioning of the sample cooler.
9. Primary pressure relief system	Before hot functional testing and at pressure conditions	The pressurizer relief tanks, associated valves, and instrumentation were checked out to verify performance of design functions. For testing of pressurizer relief and safety valves see Section II.
VII. ELECTRICAL SYSTEM TESTS		
	Done during preoperational testing	

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
VIII. CONTAINMENT SYSTEMS		
1. Containment ventilation system	Before and/or during hot functional testing	The system was operated to balance air flows and to verify the ability to maintain temperatures below maximum allowable limits.
2. Postaccident heat removal system (containment sprays)	Before criticality	Tests were performed to verify pump operating characteristics, response to control signals, and sequencing of the pumps, valves, and controller (and to ensure that spray nozzles were unobstructed).
IX. GASEOUS RADIOACTIVITY REMOVAL SYSTEMS		
	Done during preoperational testing	
X. EMERGENCY CORE COOLING SYSTEM		
1. Accumulator	During hot functional testing	Flow through the accumulator lines was initiated to demonstrate that the check valves were free to open. Tests were also made to verify that accumulator pressure could be maintained.
XI. FUEL STORAGE AND HANDLING SYSTEM		
1. Spent-fuel storage radiation monitoring equipment	Before plant start-up	Refer to Table 13.5-1, Section XIII, Item 1.
XII. REACTOR COMPONENT HANDLING SYSTEM		
1. Reactor component handling system (polar crane)	Before use for installation of components within the containment	Testing was conducted on the polar crane in accordance with standard crane testing procedures during steam generator replacement.
XIII. RADIATION PROTECTION SYSTEM		
	Done during preoperational testing	

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 13.5-2 (CONTINUED)

LIST OF START-UP TESTS AND CHECKS

Test or Check	Plant Condition/Prerequisite	Test Objective
	XIV. INITIAL CRITICALITY AND LOW-POWER TESTS	
1. Initial criticality	Plant at hot shutdown	The objective was to bring the reactor critical from the plant conditions specified. Before the start of rod withdrawal, the nuclear instrumentation had been aligned, checke0d, and conservative reactor trip setpoints made per procedures. At preselected points in rod withdrawal, data were taken and inverse count rate plots made to enable extrapolating to the expected critical rod position. In addition, the following tests associated with modified systems were performed: steam generator water-hammer test, blowdown system capability test, and thermal expansion monitoring.
	XV. POWER ASCENSION	
1. Power ascension	Criticality	Normal postrefueling testing applied for power ascension. In addition, the following design tests associated with modified systems were performed: a. Steam generator carryover tests. b. Steam generator recirculation ratio test. c. Steam generator thermal and hydraulic performance verification. d. Steam generator water level stability and control demonstration. e. Condensate polishing performance testing. f. Load-rejection testing with condensate polisher.

Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 14

Intentionally Blank

Chapter 14: Safety Analysis
Table of Contents

Chapter 14: Safety Analysis
Table of Contents (continued)

Chapter 14: Safety Analysis
Table of Contents (continued)

Chapter 14: Safety Analysis
Table of Contents (continued)

Chapter 14: Safety Analysis
Table of Contents (continued)

Chapter 14: Safety Analysis
Table of Contents (continued)

Chapter 14: Safety Analysis

List of Tables

Chapter 14: Safety Analysis

List of Tables (continued)

Chapter 14: Safety Analysis

List of Tables (continued)

Intentionally Blank

Chapter 14: Safety Analysis

List of Figures

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Chapter 14: Safety Analysis

List of Figures (continued)

Intentionally Blank

CHAPTER 14 SAFETY ANALYSIS

An assessment of the impact of using inputs and acceptance criteria derived from the latest fuel performance models and methods was performed for the Surry Non-LOCA safety analyses. This assessment concluded that the results generated using the RETRAN-3D computer code remain valid for most Non-LOCA analyses, even with the effects of Thermal Conductivity Degradation (TCD) included through the use of the latest fuel performance models and methods. One analysis determined to require reanalysis using updated fuel performance inputs was the RCCA Ejection accident. The results of the new analysis demonstrate that the applicable acceptance criteria continue to be met with consideration of TCD using the latest fuel performance models and methods.

14.1 GENERAL

This chapter evaluates the safety aspects of the station and demonstrates that the station can be operated safely and that exposures from credible accidents are less than or equal to the limits of 10 CFR 50.67 or Regulatory Guide 1.183, as applicable.

This chapter is divided into sections, each dealing with a different behavior category. The sections are as follows:

1. Core and Coolant Boundary Protection Analysis, Section 14.2.

   The incidents presented in Section 14.2 are associated with an individual unit within the station.

2. Standby Safeguards Analyses, Section 14.3.

   The accidents presented in Section 14.3 are steam generator tube rupture, steam-line break, and control-rod ejection. High-energy line breaks outside containment are discussed in Appendix 14B (Reference 1).

3. General Station Accident Analysis, Section 14.4.

   The accidents presented in Section 14.4 are associated with shared systems and facilities that may cause the release of radioactive material to the environment.

4. Loss-of-Coolant Accident (including the design-basis accident), Section 14.5.

   The loss-of-coolant accident, or the rupture of a reactor coolant pipe, is the worst accident case and is the primary basis for the unit design requirements. It is shown that even this accident meets the limits of 10 CFR 50.67, assuming that the core has been operating at 2605 MWt. This core power level is conservative compared to 100.38% of the rated power level of 2587 MWt (i.e., 2596.9 MWt).

All accident analyses were originally performed assuming the use of Zircaloy fuel rod cladding. The impact of the use of ZIRLO as an alternate cladding material was evaluated by Westinghouse (Reference 2). The properties of these two zirconium-based alloys are essentially identical except for the temperature at which the alpha to beta phase change occurs, and its related effect on the thermophysical properties (particularly the specific heat over the phase transformation temperature range). Therefore, the use of ZIRLO does not affect the analyses of non-LOCA accidents for which the clad temperature remains below the ZIRLO phase change temperature (1380°F). This includes all Condition I and Condition II events. The only non-LOCA accident analyses in which the clad temperatures are predicted to reach 1380°F or greater are the locked rotor analysis (Section 14.2.9.2) and the rupture of a control rod mechanism housing (Section 14.3.3). The effect of the use of ZIRLO cladding is discussed in the applicable sections for these accident analyses. The impact of the use of the ZIRLO alloy on the large break LOCA (Section 14.5.1) and the small break LOCA (Section 14.5.2) analyses was also assessed.

Topical Report VEP-NE-2-A (Reference 3) describes the calculation of "retained DNBR margin" as the difference between the DNBR design limit (i.e., Safety Analysis Limit) and the Statistical Design Limit (SDL). The available retained DNBR margin is evaluated for each reload core, considering DNBR penalties for generic fuel design issues (e.g., fuel rod bow), cycle-specific violations of limits (e.g., fuel rod power census), and plant operating conditions. Surry UFSAR Section 3.4.3.5 also summarizes the applicable uses of retained DNBR margin.

The Surry Improved Fuel (SIF) is no longer in use at Surry. While the basis for most transient analyses of the Chapter 14 events were performed with the SIF design and were demonstrated to be applicable to the Westinghouse 15x15 Upgrade fuel, the DNBR analyses of record have been updated explicitly to reflect the 15x15 Upgrade fuel design.

For the implementation of the Westinghouse 15 x 1 5 Upgrade fuel design at Surry, all accident analyses were reviewed for potential impact upon the NSSS predictions. The 15 x 15 Upgrade fuel assembly is described in Section 3.3 of the UFSAR. The change in cladding from ZIRLO to Optimized ZIRLO (Reference 5) as approved by the NRC (Reference 8) does not significantly change the cladding material properties. Furthermore, there are no significant changes in fuel properties between the 15 x 15 SIF product and the 15 x 15 Upgrade fuel design. Since the changes in material properties are negligible, no transient reanalysis for the non-LOCA events (UFSAR Sections 14.2 and 14.3) was performed for the 15 x 15 Upgrade fuel design.

The implementation of the 15 x 15 Upgrade fuel design has an impact on the calculated DNBR results for the Chapter 14 accident analyses. The DNBR analyses were conducted using the VIPRE-D thermal-hydraulic code (Reference 6) and the WRB-1 and W-3 CHF correlations. In Reference 7, the NRC approved the use of the VIPRE-D/WRB-1/W-3 code/correlation pairs and the supporting DNB statepoint calculations for the 15 x 15 Upgrade fuel design. VIPRE-D/WRB-1 together with the Virginia Power Statistical DNBR Evaluation Methodology (Reference 3) has been applied to the accidents listed in Section 3.2.3. Statepoints for applicable DNB events were analyzed with VIPRE-D/WRB-1 at 2589.3 MWt for full-power, statistically-treated events. All statistically-treated DNB events show acceptable DNB performance for the Westinghouse 15 x 15 Upgrade fuel design at 2589.3 MWt core thermal power. The analyzed core power is bounding for the measurement uncertainty recapture (MUR) uprated core power of 2587 MWt. The deterministic events (see Section 3.2.3) analyzed with VIPRE-D/W-3 code/correlation pair are not impacted by the MUR (Reference 4).

Subsequent to the implementation of the Westinghouse 15 x 15 Upgrade fuel design, the ABB-NV and WLOP DNB correlations were approved for use as a replacement for the W-3 DNB correlation. Consistent with the implementation of the 15 x 15 Upgrade fuel design, a DNBR analysis for the affected events (Rod Withdrawal from Subcritical and Main Steamline Break) was performed using the ABB-NV and WLOP DNB correlations. In Reference 9, the NRC approved the use of the VIPRE-D/ABB-NV and VIPRE-D/WLOP code correlation pairs and the supporting DNB statepoint calculations for the Westinghouse 15 x 15 Upgrade fuel design at Surry.

The safety analyses described in Chapter 14 have been updated to support the following DNB analysis configurations:

- Westinghouse 15x15 Upgrade fuel with VIPRE-D/WRB-1 correlation pair with a full power $F\Delta H$ limit of 1.56 for statistical DNB calculations and VIPRE-D/W-3 code correlation pair with a full power $F\Delta H$ limit of 1.62 $F\Delta H$ for deterministic DNB calculations
- Westinghouse 15x15 Upgrade fuel with VIPRE-D/WRB-1 correlation pair with a full power $F\Delta H$ limit of 1.635 for statistical DNB calculations and VIPRE-D/ABB-NV or VIPRE-D/WLOP code correlation pairs with a full power $F\Delta H$ limit of 1.70 $F\Delta H$ for deterministic DNB calculations

The ability of the automatic rod control system to withdraw rods from the core has been eliminated (Chapter 7). This prevents addition of positive reactivity by rod withdrawal in response to transient event conditions thereby resulting in lower power during the event. Automatic rod control cases are retained herein for the Excessive Heat Removal Due to Feedwater System Malfunctions (Section 14.2.7) and Excessive Load Increase Incident (Section 14.2.8) events, even though they are no longer credible, as they continue to bound the current plant design.

14.1 REFERENCES

1. Letter from Vepco to AEC, Subject: *Submittal of FSAR Appendix D (Effects of Piping System Breaks Outside Containment),* dated June 22, 1973.

2. S. L. Davidson (Ed.), et al, *VANTAGE+ Fuel Assembly Reference Core Report,* WCAP-12610-P-A (Proprietary), April 1995.

3. VEP-NE-2-A, *Statistical DNBR Evaluation Methodology*, June 1987.

4. Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Measurement Uncertainty Recapture Power Uprate (TAC Nos. ME2393 and ME3294)*, ML101750002, Dominion Serial Number 10-580, September 24, 2010.

5. H. H. Shah and P. Schueren, *Optimized ZIRLO™,* WCAP-12610-P-A and CENPD-404-P-A, Addendum 1-A, July 2006.

6. DOM-NAF-2-A, *Reactor Core Thermal-Hydraulics Using the VIPRE-D Computer Code*.

7. Letter from K. Cotton (NRC), to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Request for Technical Specification Revisions Related to the Core Operating Limits Report (TAC Nos. ME2591 and ME2592)*, October 19, 2010, Serial No. 10-645.

8. Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding the Use of Optimized ZIRLO™ Fuel Rod Cladding (TAC Nos. ME3343 and ME3344)*, Serial No. 10-669, December 22, 2010; as amended by Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Corrections to Amendments Regarding the Use of Optimized ZIRLO™ Fuel Rod Cladding (TAC Nos. ME3343 and ME3344)*, Serial No. 10-755, December 23, 2010.

9. Letter from V. Sreenivas (USNRC) to D. A. Heacock (Dominion), *North Anna and Surry Power Stations Units 1 and 2, Issuance of Amendments Regarding Addition of an Analytical Methodology to the North Anna and Surry Core Operating Limits Reports and an Increase to the Surry Minimum Temperature for Criticality (TAC Nos. MF2364, MF2365, MF2366, and MF2367),* Dominion Serial No. 14-410, dated August 12, 2014.

14.2 CORE AND COOLANT BOUNDARY PROTECTION ANALYSIS

14.2.1 Uncontrolled Control-Rod Assembly Withdrawal From a Subcritical Condition

A control-rod assembly withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by the withdrawal of control-rod assemblies, resulting in a power excursion. While the probability of a transient of this type is extremely low, such a transient could be caused by a malfunction of the reactor control or control rod drive systems. This could occur with the reactor either subcritical or at power. The “at power” case is discussed in Section 14.2.2.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from a shutdown condition to a low-power level during start-up by control-rod withdrawal. Although the initial start-up procedure used the method of boron dilution, the normal start-up is with control-rod assembly withdrawal. Control-rod assembly motion can cause much faster changes in reactivity than can be made by changing boron concentration.

The control-rod drive mechanisms are wired into preselected banks, and these bank configurations are not altered during core life. The assemblies are therefore physically prevented from being withdrawn in other than their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. The control-rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable-speed rod travel. The maximum reactivity insertion rate is postulated in a detailed analysis assuming the simultaneous withdrawal of the combination of the two rod banks of the maximum combined worth at maximum speed.

Should a continuous control-rod assembly withdrawal be initiated from subcritical or low power conditions, the transient will be terminated by the following automatic safety features:

1. Source range flux level trip—actuated when either of two independent source range channels indicates a flux level above a preselected, manually adjustable value. This trip function may be manually bypassed when either intermediate-range flux channel indicates a flux level above the source range cutoff power level. It is automatically reinstated when both intermediate-range channels indicate a flux level below the source range cutoff power level.
2. Intermediate-range control-rod stop—actuated when either of two independent intermediate-range channels indicates a flux level above a preselected, manually adjustable value. This control-rod stop may be manually bypassed when two out of the four power range channels indicate a power level above approximately 10% of full power. It is automatically reinstated when three of the four power range channels are below this value.
3. Intermediate-range flux level trip—actuated when either of two independent intermediate-range channels indicates a flux level above a preselected, manually adjustable value. This trip function may be manually bypassed when two of the four power range channels are reading above approximately 10% of full power and is automatically reinstated when three of the four channels indicate a power level below this value.

4. Power range flux level trip (low setting)—actuated when two out of the four power range channels indicate a power level above approximately 25% of full power. This trip function may be manually bypassed when two of the four power range channels indicate a power level above approximately 10% of full power and is automatically reinstated when three of the four channels indicate a power level below this value.

5. Power range control-rod stop—actuated when one out of the four power range channels indicates a power level above a preset setpoint. This function is always active.

6. Power range flux level trip (high setting)—actuated when two out of the four power range channels indicate a power level above a preset setpoint. This trip function is always active.

Reactor protection for subcritical and low power rod withdrawal events has traditionally been assumed to be provided by the Power Range high flux trip (low setpoint) for events initiated both above and below permissive P-6. Source Range protection was assumed to not be available, since the Source Range channel lacked the redundancy required to assume trip availability in UFSAR accident analyses. Technical Specifications require two available Source Range Channels below permissive P-6. In conjunction with Source Range trip bistable operability testing to verify Source Range channel response characteristics, this validates the assumption of Source Range trip availability in accident analyses. Technical Specifications also impose an allowable Source Range channel outage time for power levels below P-6. This ensures start-up protection by providing confirmation of the availability of the Source Range channel.

Rod withdrawal from subcritical events may be initiated from above or below permissive P-6. Below P-6, one or two reactor coolant pumps may be operating, or reactor coolant system (RCS) cooling may be provided by the Residual Heat Removal (RHR) system. For any operating condition below P-6, Source Range protection or open trip breakers provide reactor protection against a rod withdrawal from subcritical event. Additional protection is provided by the other operable reactor protection system circuitry, including the Intermediate Range and Power Range (low setpoint) reactor trips. As was demonstrated in the North Anna Core Uprating submittal (Reference 27) and subsequent responses to NRC questions (References 28 & 29) events initiated from allowable operating conditions below P-6 will not result in significant power generation of core heat flux when a reactor trip is actuated on the Source Range channel. This conclusion is also applicable to Surry. Therefore, reactor protection is provided for all operating conditions below P-6, including one-RCP, two-RCP, and RHR operation.

The nuclear power response to a continuous reactivity insertion originating above P-6 is characterized by a very fast rise terminated by the reactivity feedback effect of the negative fuel temperature coefficient. This self-limitation of the initial power burst results from a fast negative fuel temperature feedback (Doppler effect) and is of prime importance during a start-up incident since it limits the power to a tolerable level before external control action. After the initial power burst, the nuclear power is momentarily reduced and then if the incident is not terminated by a reactor trip, the nuclear power increases again, but at a much slower rate.

The termination of the start-up incident by the above protection channels prevents core damage. In addition, the reactor trip from high reactor pressure serves as a backup to terminate the incident before an overpressure condition could occur.

14.2.1.1 **Method of Analysis**

The rod withdrawal from subcritical event was analyzed using the RETRAN computer code and the associated Virginia Power reactor system transient methodology (Reference 12). The analysis includes the simulation of the plant neutron kinetics, and the core thermal and hydraulic feedback equations. The RETRAN code calculates nuclear power, core heat flux, average fuel, clad and coolant temperatures. The MDNBR for the 15 x 15 Upgrade fuel design was determined at the statepoint for the DNB limiting case of the transient using the VIPRE-D computer code (Reference 36).

The analysis assumes the operation of all three reactor coolant pumps. Technical Specification 3.1.A.1.a prohibits achieving criticality with less than three reactor coolant pumps operating. The following additional assumptions were made to provide conservative results for this analysis:

1. Since the magnitude of the nuclear power peak reached during the initial part of the transient, for any given rate of reactivity insertion, is strongly dependent on the Doppler power reactivity coefficient, a conservative fuel-temperature-dependent Doppler coefficient was used.

2. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and the moderator is much longer than the nuclear flux response constant. However, after the initial nuclear flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. A conservative value of +6 pcm/°F was used in the analysis since the positive value yields the maximum peak core heat flux (1 pcm = 10^{-5} $\Delta k/k$).

3. The reactor is assumed to be at hot zero power with a T_{avg} of 547°F. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-to-water thermal conductivity, a larger fuel thermal capacity, and a less negative (smaller absolute magnitude) Doppler coefficient. The less negative Doppler coefficient reduces the Doppler feedback effect, thereby increasing the nuclear flux peak. The high nuclear flux peak combined with a high fuel thermal capacity and large thermal conductivity yields a larger peak heat flux. Initial multiplication (k_o) is assumed to be 1.0 since this results in the maximum nuclear power peak.

4. The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and control-rod assembly release, are taken into account. A 10% increase has been assumed for the power range flux trip setpoint, raising it from the nominal value of 25% to 35%. The rise in nuclear flux is so rapid that the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible.

5. The rate of negative reactivity insertion corresponding to the trip action is based on the assumption that the highest worth control rod assembly is stuck in its fully withdrawn position. A conservatively low value was assumed for the total trip reactivity from zero power.

6. The maximum positive reactivity insertion rate assumed (112.5 pcm/sec) is greater than that for the simultaneous withdrawal of the combination of the two control banks having the greatest combined worth at maximum speed (45 in/min).

7. The initial power level was assumed to be below the power level expected for any shutdown condition. The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

8. The delayed neutron fraction (β_{eff}) was assumed to be at its maximum value, as that would maximize the thermal energy released into the coolant.

9. On the secondary side, the condenser dump valves are assumed closed, thus causing a pressure buildup that would contribute to the heatup of the primary system.

10. Since this event is evaluated at hot zero power conditions (0% rated core power), the UFSAR analysis of record is unaffected by the MUR power uprate to 2587 MWt.

For the pressure-limiting case, to conservatively overestimate the pressurization in the RCS, the following additional assumptions are made:

1. Initial pressurizer pressure is 2280 psia (30 psi above the nominal).
2. Initial pressurizer level is 5% above the nominal.
3. PORVs and pressurizer sprays that would mitigate the pressurization are not credited.
4. The PSV loop seals are filled with water. Displacing the liquid in the loop seal causes a delay in the opening of the PSVs, thus driving the primary system pressures higher.

In the DNB-limiting case, the following specific assumptions are made to decrease the primary pressurization and increase the energy released into the coolant, thus minimizing the calculated margin to DNB:

1. Initial pressurizer pressure and level are held at their nominal values.
2. Pressurizer sprays and PORVs are credited, thereby mitigating system pressurization.
3. For the MDNBR calculation, conservative values for the pressurizer pressure, RCS flow and the bypass flow fraction are used.

14.2.1.2 **Results**

Figure 14.2-2 shows the effect of the initial power level on peak heat flux for various reactivity insertion rates from 20 to 60 pcm/sec. It shows that peak heat flux initially decreases with increasing initial power level and then, depending on the rate, it increases again and approaches 35% of full power (reactor trip is assumed to be initiated at this value). It can also be seen that for the faster insertion rates, which result in the greatest energy addition, the flux peak is greatest for the lowest initial power level.

Figures 14.2-1, 14.2-3 and 14.2-4 show the transient behavior for a DNB-limiting case, with the incident terminated by reactor trip at 35% power. As seen in Figure 14.2-1, the nuclear power increases to the trip setpoint in 6.8 seconds. The power then overshoots to approximately 966%, but only momentarily. Therefore, the energy release and the fuel temperature increase are moderate. The thermal flux response, of interest for DNB considerations, is shown in Figure 14.2-3. The beneficial effect of the inherent thermal lag of the fuel is evidenced by a peak heat flux of only 53% of 2546 MWt (52% of 2587 MWt). There is an adequate margin to DNB during the transient since the rod surface heat flux remains below the design value, and there is a high degree of subcooling at all times in the core. Figure 14.2-4 shows the response of the average fuel, cladding and coolant temperatures. The average fuel temperature peaks at 956°F which is much lower than the nominal full power value of 1311°F. The average coolant temperature rises to only 566.4°F while the clad temperature peaks at 597°F. A VIPRE-D calculation for the 15 x 15 Upgrade fuel design using a statepoint with adjustments to the thermal-hydraulic input variables gives a MDNBR above the applicable SAL listed in Section 3.2.3.

The pressure-limiting case results in a pressurizer pressure peak of 2656 psia at 11.6 seconds, while the overall primary system peaks at 2720 psia in the cold leg at 11.8 seconds.

14.2.1.3 **Conclusion**

It is concluded that, in the unlikely event of a control rod assembly withdrawal incident from subcritical conditions, the core and reactor coolant system are not adversely affected, as the peak thermal power and the peak coolant temperature in the DNB-limiting case are well below their nominal full power values. An explicit statepoint calculation using very conservative assumptions results in a minimum DNBR above the design limit.

In the case that examines primary system pressure, it can be shown that the peak RCS pressure will be less than 110% of design pressure.

14.2.2 Uncontrolled Control-Rod Assembly Withdrawal at Power

The Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal at Power (RWAP) event is characterized by a reactivity increase resulting from the withdrawal of one or more RCCA banks from the core during power operation. The initiating event is a postulated single failure in a control system such as the rod control system or the reactor control system or faulty action by a reactor operator. The addition of reactivity to the core tends to be distributed uniformly, due to the RCCA bank arrangement. The energy removal capabilities of the secondary system tend to lag behind the core power increase resulting from the rod bank withdrawal. This energy mismatch causes the Reactor Coolant System (RCS) pressure and temperature to increase.

The possibility exists that the core heat flux could exceed the ability of the RCS fluid to conduct the heat from the fuel, potentially leading to a Departure from Nucleate Boiling (DNB) and subsequent cladding failure. The RCS temperature and pressure transients can be limited by the operation of RCS and main steam (MS) pressure relief valves; however, the power excursion generally continues until terminated by the addition of negative reactivity from the safety control rod banks due to a reactor trip. The limiting event conditions occur shortly after safety control bank insertion, when the minimum DNB ratio (MDNBR) occurs. The Reactor Coolant Pumps (RCPs) remain operational throughout the event so that, in the absence of DNB, sufficient RCS flow exists to adequately handle the transfer of energy from the fuel to the reactor coolant.

As stated above, maintaining the fuel cladding integrity is the primary concern for the RWAP event. However, maintaining the RCS as a fission product barrier is also a concern. Specifically, the heating of the RCS fluid during a RWAP event causes the fluid density to decrease, resulting in a volumetric expansion of the fluid. Operation of the pressurizer sprays and Power Operated Relief Valves (PORVs) can mitigate the effects of the subsequent pressure increase, but do not counteract the volumetric expansion. Should the expansion of the RCS fluid continue uncontested, the potential exists for discharge of liquid through the PORVs or Pressurizer Safety Valves (PSVs). For the rod withdrawal at power event, the reactor protection system terminates the heatup of the reactor coolant system before any liquid relief occurs.

Provided the integrity of the fission product barriers is not compromised, sensible and decay heat can be removed by steaming to the condenser through the steam bypass system, to the atmosphere through the MS PORV or the Main Steam Safety Valves (MSSVs), or any combination of the three methods. Feedwater remains available to the steam generators (SGs) from either the Main Feedwater (MFW) system or the Auxiliary Feedwater (AFW) system to replenish the secondary coolant. Shortly after reactor trip, the energy removal capability of the SGs will exceed the RCS sensible and decay heat levels, and the reactor operators/automatic control systems will function to maintain the plant at the new equilibrium condition.

The automatic features of the reactor protection system that prevent core damage in a control-rod assembly withdrawal incident at power include the following:

1. Nuclear power range instrumentation actuates a reactor trip if two out of the four channels exceed an overpower setpoint.
2. Reactor trip is actuated if any two out of three delta T channels exceed an overtemperature delta T setpoint. This setpoint is automatically varied with axial power distribution and coolant temperature and pressure to protect against DNB.
3. Reactor trip is actuated if any two out of three delta T channels exceed an overpower delta T setpoint. This setpoint is automatically varied with axial power distribution and coolant temperature to ensure that the allowable heat generation rate (kw/ft) is not exceeded.
4. A high-pressure reactor trip, actuated from any two out of three pressure channels, is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.

5. A high pressurizer water level reactor trip, actuated from any two out of three level channels, is actuated at a setpoint. This affords additional protection for control-rod assembly withdrawal incidents. The Technical Specifications require that the reactor be maintained subcritical by some minimum amount until normal water level is established in the pressurizer.

6. In addition to the above-listed reactor trips, there are the following control-rod assembly withdrawal blocks:

   a. High nuclear power (one out of four).

   b. High overpower delta T (two out of three).

   c. High overtemperature delta T (two out of three).

The manner in which the combination of overpower and overtemperature delta-T trips provides protection over the full range of reactor coolant system conditions is described in Chapter 7 and in Figure 14.2-5. Figure 14.2-5 illustrates reactor coolant loop average temperature and delta-T for the design power distribution and flow as a function of primary coolant pressure. The boundaries of operation defined by the overpower delta-T trip and the overtemperature delta-T trip are represented as “protection lines” on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions a trip would occur well within the area bounded by these lines. This diagram is useful in that the limit imposed by any given DNBR can be represented as Reactor Core Safety Limit lines. The DNB lines represent the locus of conditions for which the DNBR equals the limit value. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit value. The diagram shows that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The region of permissible operation (power, pressure, and temperature) is completely bounded by the following reactor trips: nuclear overpower (fixed setpoint), high pressure (fixed setpoint), low pressure (anticipatory rate dependent setpoint), and overpower and overtemperature delta T (variable setpoints). These trips are designed to prevent a DNBR less than the applicable SAL (Section 3.2.3).

The analysis presented below shows that no fuel damage occurs by demonstrating that the DNBR limit is met for the rod withdrawal event. Also shown is that the RCS and MS system pressure relieving devices have sufficient capacities to ensure the safety of the unit without relying on the mitigating capabilities of the pressurizer pressure control or MS bypass systems.

14.2.2.1 **Method of Analysis**

The RWAP transient is analyzed with the RETRAN computer code (Reference 12) and the detailed core thermal/hydraulic analysis is performed with the VIPRE-D computer code (Reference 36) for the 15 x 15 Upgrade fuel design. The RETRAN system code simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level. The VIPRE-D code is used to calculate the DNBR for the transient using the WRB-1 CHF correlation.

For the DNBR evaluation cases, the initial power level, pressurizer pressure, and RCS average temperature are assumed to be at values consistent with the conditions at 2589.3 MWt, which bounds the MUR uprated nominal power of 2587 MWt. The effects of normal control system variations and measurement uncertainties associated with these parameters are treated statistically and incorporated into the statistical design limit (SDL) (Section 3.2.3) in accordance with Virginia Power's Statistical DNBR Methodology (Reference 17). The calculation of the DNBR is consistent with the current Technical Specifications Core Operating Limit Report limit on $F\Delta H$ as modified by a 0.3 part power multiplier.

For cases where reactor coolant system pressures are of primary interest, the initial reactor power, pressurizer pressure and RCS average temperature are assumed to be at the maximum values consistent with steady state full power operation, including allowances for calorimetric and other instrument errors. In addition these cases are performed with the pressurizer pressure relieving devices (pressurizer spray and PORVs) disabled.

All cases incorporate the assumption of 15% steam generator tube plugging. To obtain conservative results the following assumptions are made:

1. Reactivity coefficients - two cases are analyzed:
    a. Minimum reactivity feedback. A positive moderator temperature coefficient of +6.0 pcm/°F in conjunction with a least negative Doppler temperature coefficient is used in the analysis.
    b. Maximum reactivity feedback. A conservatively large negative moderator coefficient -45.0 pcm/°F and a large (in absolute magnitude) negative Doppler temperature coefficient are assumed.
2. The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 118% of conditions at 2589.3 MWt, which bounds the MUR uprated nominal power of 2587 MWt. The delta T trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.
3. The RCCA trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.
4. A spectrum of reactivity insertion rates is analyzed. The maximum positive reactivity insertion rate is greater than the maximum rate of two sequential control rod banks moving at the maximum speed with normal overlap.

The effect of rod cluster assembly movement on the axial core power distribution is accounted for by causing a decrease in overtemperature and overpower delta-T trip setpoints proportional to a decrease in margin to DNB.

14.2.2.2 **Results**

Figure 14.2-6 shows the minimum DNBR for the 15 x 15 SIF product as a function of reactivity insertion rate from initial full power operation of 2589.3 MWt (which bounds the MUR uprated nominal power of 2587 MWt) for the minimum and maximum reactivity feedback. It can be seen that the high-neutron flux and overtemperature delta-T trip setpoints provide protection over the whole range of reactivity insertion rates since the minimum DNBR for all insertion rates is greater than the applicable SAL listed in Section 3.2.3.

Figures 14.2-7 and 14.2-9 show the response of nuclear power, pressurizer pressure, and average coolant temperature to the limiting DNBR case initiated from 2589.3 MWt (0.4 pcm/sec insertion rate). The slow rod withdrawal allows for a sufficient rise in temperature and pressure to cause a trip on overtemperature delta-T. The minimum DNBR for the 15 x 15 SIF product for this case remains well above the limit as indicated by Figure 14.2-6.

Figures 14.2-10 and 14.2-11 show the minimum DNBR for the 15 x 15 SIF product as a function of reactivity insertion rate for the rod withdrawal event starting at 60% and 10% of 2546 MWt, respectively. The results are similar to the 100% of 2589.3 MWt (100.1% of 2587 MWt) power case, except that as the initial power is decreased, the range over which the overtemperature delta-T trip is effective is increased. In all cases, the DNBR is greater than the applicable SAL (Section 3.2.3).

Figures 14.2-12 and 14.2-14 show the nuclear power, RCS average temperature, and cold leg pressure response to the limiting overpressure rod withdrawal incident. Sensitivity cases performed to maximize RCS pressure indicate that limiting results occur for an assumed initial power of 12% of 2546 MWt with a reactivity insertion rate of 55 pcm/sec and minimum reactivity feedback. The reactor trips on high flux at 12.63 seconds. The cold leg pressure reaches a peak value of 2699.00 psia at 13.8 seconds into the transient.

Cases performed to maximize the main steam pressure (maximize the RCS average temperature prior to trip) show that the maximum main steam pressure occurs for rod withdrawal events initiated at 60% of 2546 MWt. The cases providing the maximum main steam pressure are those which allow a gradual but large rise in the RCS average temperature. These are cases with low insertion rates and minimum reactivity feedback or relatively high insertion rates with maximum reactivity feedback. These cases trip on overtemperature delta-T and achieve approximately the same RCS temperature.

Therefore, the maximum main steam pressure is fairly constant (1190 psia) over a range of insertion rates. The analyses support up to 15% steam generator tube plugging.

The MDNBR for the 15 x 15 Upgrade fuel design was determined for the RWAP event at the statepoints for the DNB-limiting cases of the transient using the VIPRE-D computer code (Reference 36). It was determined that the MDNBR for all RWAP cases was above the applicable SAL (Section 3.2.3).

14.2.2.3 **Conclusions**

This analysis indicates that for an uncontrolled rod withdrawal at power event, the following criteria are met:

1. The minimum DNBR remains above the applicable SAL (UFSAR Section 3.2.3).
2. Pressure at the most limiting RCS location is less than 110% of RCS design pressure, or 2750 psia (the Emergency Condition Stress Limit specified in Section III of the ASME Code).
3. Pressure at the most limiting Main Steam System (MSS) location is less than 110% of MSS design pressure, or 1210 psia (the Emergency Condition Stress Limit specified in Section III of the ASME Code).

14.2.3 Malpositioning of the Part Length Control Rod Assemblies

The part length control rod assemblies have been removed from the core.

14.2.4 Control-Rod Assembly Drop/Misalignment

Control-rod misalignment accidents include (1) dropped full length assemblies, (2) dropped full-length assembly groups, and (3) statically misaligned assemblies.

Each control-rod assembly has a rod position indicator channel that displays the position of the assembly. The displays of assembly position are grouped for the operator's convenience. Fully inserted assemblies are further indicated by rod bottom indicators on the redundant rod position flat panel displays. Bank (demand) position is also indicated. Except during start-up physics testing and control-rod exercise testing, the assemblies are moved in preselected banks and the banks are moved in the same preselected sequence.

The dropping of a control-rod assembly could occur only when the drive mechanism is de-energized. This would result in a power reduction and an increase in the hot-channel factor. If no protective action occurred, the reactor control system would restore the power to the level that existed before the incident. This would lead to a reduced safety margin or possibly DNB, depending on the magnitude of the hot-channel factor.

Dropped assemblies or banks are detected by:

1. A sudden drop in the core power level.
2. Asymmetric power distribution as seen on ex-core neutron detectors (Reference 1) or core exit thermocouples.

3. Rod bottom indicators on the redundant rod position flat panel displays.
4. A rod deviation alarm.

The rod bottom condition signal from the rod position indication system is provided for each control-rod assembly. The initiation of this signal is independent of lattice location, reactivity worth, or power distribution changes inherent with the dropped control-rod assembly. The other independent indication of a control-rod assembly drop is obtained by using the ex-core power range channel signals. This rod drop detection circuit is actuated upon the sensing of a rapid decrease in local flux such as could occur from the depression of flux in one region by a dropped control-rod assembly. This detection circuit is designed such that normal load variations do not cause it to be actuated.

A rod drop signal from any control-rod assembly position indication channel, or from one or more of the four power range channels, initiates alarms in the main control room.

Misaligned assemblies are detected by:

1. Asymmetric power distribution as seen on ex-core neutron detectors or core exit thermocouples.
2. A rod deviation alarm.

The resolution of the rod position indicator channel is ±5% of span (±12 steps) under steady state conditions. The deviation of any assembly from its bank by twice this distance (10% of span or 24 steps) will not cause power distributions worse than the design limits. The rod deviation alarm alerts the operator to rod deviation in excess of 10 steps or 4.3% of span.

If one or more of the rod position indicator channels should be out of service, detailed operating instructions in accordance with Technical Specification requirements are followed to ensure the alignment of the nonindicating assemblies.

14.2.4.1 **Methodology of Analysis**

The dropped RCCA(s) event is conservatively evaluated. This evaluation consists of three analyses, transient, nuclear, and thermal/ hydraulic. These analyses provide (l) statepoints, i.e., the reactor power, pressure, and temperature at the most limiting time in the transient, (2) the radial peaking factor at the most limiting conditions in the transient, and (3) the DNB analysis at the conditions determined by 1 and 2.

These analyses are performed using a parametric approach so that cycle specific conditions may be evaluated using the data generated from the three analyses above. On a reload basis an analysis is made using two key cycle specific parameters (the rod worth available for withdrawal and the moderator temperature coefficient) to determine the radial peaking factor prior to the dropped RCCA(s) event necessary to produce the applicable SAL (Section 3.2.3) during the transient for a range of dropped RCCA(s) worths. This range covers those which could be expected for a three loop plant like Surry. These predrop radial peaking factors are compared to the reload design predictions to confirm that the limiting predrop conditions for DNB do not occur during the cycle.

The transient response is calculated using either the LOFTRAN (Reference 4) or the RETRAN (Reference 12) code. These codes simulate the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. Nuclear models are used to obtain hot channel factors consistent with the primary system conditions at the statepoints generated by the transient simulation. The DNB design basis is shown to be met using the VIPRE-D code (Reference 36) for the 15 x 15 Upgrade fuel design by combining the primary conditions from the transient analysis with the hot channel factor from the nuclear analysis. The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in Reference 18.

A DNBR penalty of 3.0% will be applied to account for the increased bypass flow due to the conversion to upflow configuration. This DNBR penalty is conservative and applicable to all DNB events and will be deducted from the retained margin for the Westinghouse 15x15 Upgrade fuel product during the core reload thermal-hydraulic evaluation in accordance with NRC approved methodology in VEP-NE-2-A (Reference 17).

The ability of the automatic rod control system to withdraw rods from the core has been eliminated. This prevents addition of positive reactivity by rod withdrawal in response to transient event conditions thereby resulting in lower power during the event. The event cases with automatic rod control are no longer credible and are therefore not considered.

14.2.4.2 **Results**

For the dropped RCCA(s) event, power may be reestablished either by reactivity feedback or control bank withdrawal.

Following a dropped RCCA(s) in manual rod control, the plant will establish a new equilibrium condition. The drop will insert negative reactivity which causes the core power level to fall. The mismatch in power between that demanded by the turbine and that generated by the reactor core causes the reactor temperature to fall. The falling temperature in turn causes the reactor coolant pressure to fall. The plant will be tripped on low pressurizer pressure before the DNBR falls to the applicable SAL (Section 3.2.3). This process without control system interaction is monotonic, thus removing power overshoot as a concern and establishing the automatic rod control mode of operation as the limiting case.

The automatic rod withdrawal feature of the rod control system has been disabled. Therefore, following a dropped rod event the plant will establish a new equilibrium condition, and a power overshoot is not predicted. Figures 14.2-15 and 14.2-16 are generic curves for a typical transient response to a dropped RCCA (or RCCAs) without automatic rod withdrawal.

Uncertainties in the initial conditions are included in the DNB evaluation as described in Reference 17. On a reload basis, it is shown that the minimum DNBR remains greater than the applicable SAL (Section 3.2.3)

14.2.4.3 **Conclusions**

For all cases the DNB design basis is met by demonstrating that the DNBR is greater than the applicable SAL (Section 3.2.3).

14.2.5 Chemical and Volume Control System Malfunction

14.2.5.1 **Identification of Causes and Accident Description**

Reactivity can be added to the core by feeding primary grade water into the reactor coolant system via the reactor makeup portion of the chemical and volume control system. Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water during normal charging to that in the reactor coolant system. The chemical and volume control system is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valve creates a dilution flow path to the reactor coolant system. Inadvertent dilution from this source can be readily terminated by closing the control valve. For makeup water to be added to the reactor coolant system at pressure, at least one charging pump must be running in addition to a primary grade water transfer pump.

The boric acid from the boric acid tank is blended with primary grade water in the blender; the composition is determined by the preset flow rates of boric acid and primary grade water on the control board. Two separate operations are required to dilute: (l) The operator must-switch from the automatic makeup mode to the dilute mode; (2) The blender switch must be turned to the "on" position. Omitting either step prevents dilution, making the possibility of an inadvertent dilution very remote.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the chemical and volume control system. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction.

14.2.5.2 **Method of Analysis**

To cover all phases of plant operation, boron dilution during Refueling Shutdown, Cold Shutdown, Intermediate Shutdown, Hot Shutdown, Reactor Critical, and Power Operation are considered. Explicit analyses are performed for Reactor Critical and Power Operation. Analyses are not performed for the shutdown operating modes as discussed in Section 14.2.5.3. The case of an inadvertent dilution during a planned dilution or makeup activity is not considered here as an accident analysis, since evaluation of such dilutions is not required by the Standard Review Plan. Boron dilution during start-up of an inactive loop is discussed in UFSAR Section 14.2.6.

The following parameter value ranges were considered in the boron dilution analyses for Power Operation and Reactor Critical operating modes:

1. Steam Generator Tube Plugging Fraction (SGTPF): 0% to 15% SGTP. The effective RCS Volume excludes the pressurizer, reactor vessel upper head, and plugged steam generator tube volumes.
2. Maximum Dilution Flow Rate. When the reactor coolant system is pressurized and the plant is in Power Operation or Reactor Critical mode, the rate of addition of unborated water is limited by the capacity of the charging pumps. The maximum dilution flow rate of 165 gpm, corresponding to the maximum charging flow rate of a single charging pump to a pressurized RCS, is assumed in the analysis when in Reactor Critical or Power Operation modes when Technical specifications do not require Primary Grade water isolation.
3. Bounding values of dilution flow density and RCS Water Density were assumed (maximum dilution density and minimum RCS density).
4. Minimum Shutdown Margin at Power: 1.77% $\Delta K/K$.

14.2.5.3 **Boron Dilution in Shutdown Operating Modes**

Technical Specifications require that the PG makeup water flow path be closed during Refueling Shutdown, Cold Shutdown, Intermediate Shutdown and Hot Shutdown, thereby preventing a high flow rate boron dilution event from occurring during these operating conditions. To satisfy this requirement, manual valve 1-CH-233 (2-CH-233 for Unit 2), the PG makeup water isolation valve, is secured in the closed position. As an alternative, Technical Specifications allow that manual valves 1-CH-212, 1-CH-215 and 1-CH-218 (2-CH-212, 2-CH-215, and 2-CH-218 for Unit 2) may be secured in the closed position if for any reason it is desired that 1-CH-223 (2-CH-223) be maintained open. This alternative combination of valve closures has the same effect as closing valve 1-CH-223 (2-CH-223). The PG makeup water flow path isolation is also required to be closed within 15 minutes following a planned dilution in all shutdown operating modes. (Allowances are provided in the Technical Specifications for relaxing PG water isolation requirements during approach to critical and immediately after shutdown.) Compliance with Technical Specification requirements for closing the PG water flow path ensures that the highest capacity source of PG water is isolated from the reactor coolant system. Therefore, a high flow rate boron dilution event is not credible in the shutdown operating modes.

It is recognized that there are many paths for dilution of the moderator. The rationale behind isolating the main primary grade water flow path is to preclude dilutions that would cause a rapid, uncontrolled decrease in shutdown margin. Low dilution flow rates have a high probability of being identified and corrected before a significant loss of shutdown margin occurs.

There are a number of plant features that provide diagnostic indication of an inadvertent low flow rate boron dilution in the shutdown modes. These indications include audible count rate and high flux at shutdown alarm from the source range nuclear instruments. Reload core design checks have been implemented to ensure that the source range nuclear instruments provide effective indication of changes in core reactivity in subcritical conditions. In addition, RCS letdown divert valve position, VCT level, PG tank levels and PG header flow rate all provide indication in the Main Control Room of a potential mismatch between charging and letdown and unexpected usage of PG water.

14.2.5.4 **Boron Dilution at Reactor Critical and Power Operation**

The analysis of the boron dilution event at reactor critical conditions indicates that at least 15 minutes are available from positive indication of a dilution in progress (alarm or reactor trip) to loss of shutdown margin for corrective operator action. The analysis conservatively assumed a minimum of 1.77% shutdown margin at the beginning of the dilution.

The boron dilution at power event has been analyzed for the rods in automatic and manual control cases. The results of the analysis indicate that 15 minutes are available after positive indication of a dilution in progress (reactor trip) for corrective operator response before a return to criticality.

The “rods in automatic control” case was shown to be bounded by the “rods in manual control” case. To illustrate, if an initial boron concentration, a dilution flow rate, and a boron worth are assumed, the “rods in manual” case will result in a reduction of shutdown margin potentially beyond that of the minimum shutdown margin required by Technical Specifications. If rods are in automatic, rod insertion due to T_{avg} -T_{ref} deviation will result in a rod insertion limit (indicating dilution is in progress) before the rod bank reaches rod insertion limit, the point at which minimum shutdown margin is defined. Therefore, the “rods in manual” case is assumed to consume a portion of minimum shutdown margin resulting in an operator response time which is always less than that of the corresponding “rods in automatic control” case. The automatic control case is therefore bounded by the manual control case. With either automatic or manual rod control, boron dilution events initiated at or below 100% power will result in an RCS temperature increase and, ultimately, in a high RCS temperature alarm. Positive indication of a dilution in progress in the analyzed boron dilution at power case (100% power; manual rod control), is assumed to be provided by the OTΔT reactor trip. In this analysis case, the high RCS temperature alarm is conservatively assumed to not actuate.

The reactivity transient resulting from an inadvertent boron dilution is essentially identical to that of a control rod assembly withdrawal accident. The reactivity insertion rates used in the analysis are well within the range of reactivity insertion rates considered in UFSAR Section 14.2.2, *Uncontrolled Control-Rod Assembly Withdrawal at Power*. If the reactor is in manual control and the operator takes no action to correct an inadvertent boron dilution, the power and temperature will rise to the overtemperature delta-T trip setpoint. Before the overtemperature delta-T trip, an overtemperature delta-T alarm and turbine runback would be actuated. The time to trip varies with the reactivity insertion rate (which is a function of boron concentration and boron worth) and with the temperature and power reactivity feedback of the core (which are largely functions of burnup). It was shown that 15 minutes are available after a reactor trip before the reactor can return to critical, conservatively assuming a minimum of 1.77% shutdown margin at the beginning of the dilution.

The results of the reactor critical and both the automatic and manual control cases of the boron dilution at power analyses indicate that at least 15 minutes are available, from positive indication of a dilution in progress (alarm or reactor trip) to loss of shutdown margin, for corrective operator response to an unplanned boron dilution.

14.2.5.5 **Conclusions**

Because of the procedures involved in the dilution process and the Technical Specification PG water isolation requirement, a high flow rate boron dilution is not considered credible in the shutdown operating modes. Numerous alarms and indications are available to alert the operator to any unintended low flow rate boron dilution in sufficient time for detection and corrective action prior to loss of shutdown margin.

For Reactor Critical and Power Operation modes, reload cores are designed and analyzed to ensure at least 15 minutes are available between positive indication (alarm or reactor trip) and loss of shutdown margin for corrective operator action in response to a boron dilution.

14.2.6 Start-Up of an Inactive Loop (SUIL) Accident Analysis Design Basis

14.2.6.1 **Event Description**

The SUIL accident analysis considers reactivity additions due to inadvertent introduction of cold and/or unborated water from an isolated (or previously isolated) loop. Because loop stop valve operations are prohibited at conditions other than COLD SHUTDOWN and REFUELING SHUTDOWN, inadvertent reactivity additions due to introduction of cold or unborated water at INTERMEDIATE SHUTDOWN, HOT SHUTDOWN, REACTOR CRITICAL, or POWER OPERATION are not considered.

An SUIL event is defined as an uncontrolled reduction in coolant temperature and/or boron concentration in the core region resulting from either the start-up of a reactor coolant pump (RCP) on an idle loop (the loop stop valves open case), or recirculation through a loop stop valve bypass line on an isolated loop (the loop stop valves closed case) when a reduced coolant temperature or boron concentration exists in the idle (or isolated) loop. A loop is considered idle when its hot and cold leg loop stop valves are open, but the reactor coolant pump on the loop is not operating. When no coolant temperature or boron concentration differential exists between the idle (or isolated) loop and the active portion of the reactor coolant system (RCS), the start-up of an RCP does not result in reactivity insertion, erosion of shutdown margin (SDM), power excursion, or reduction in margin to a departure from nucleate boiling (DNB) condition. Under these conditions, start-up of an RCP is simply a start-up procedure, and does not represent an SUIL event.

Because starting an RCP is a deliberate action under operator control, the initiator for an SUIL event is postulated to be multiple administrative errors. If a significant coolant temperature or boron concentration differential existed between the idle (or isolated) loop and the active portion of the RCS, starting the RCP on the idle (or isolated) loop could result in a reactivity insertion, erosion of SDM, and a power excursion. If the core heat flux exceeded the ability of the RCS fluid to conduct the heat from the fuel, the power excursion could lead to DNB and subsequent cladding failure at localized hot spots. Further, coolant expansion in the core region could lead to overpressurization of the RCS. Administrative controls governed by Technical Specifications ensure that, prior to starting an RCP, the differential coolant temperature and boron concentration between the idle (or isolated) loop and the active portion of the RCS are less than those which could result in complete loss of shutdown margin.

If the administrative controls governed by Technical Specifications are circumvented, and a differential coolant temperature and boron concentration beyond that ensured by the administrative controls is achieved, the start-up of an RCP could result in fuel cladding failure due to the onset of DNB, and potential overpressurization of the RCS. The DNB response of the fuel would be governed primarily by the core power and RCS temperature transient responses. The major contributors to the core power response are the change to the RCS boron concentration and the change to the RCS fluid temperature. Power changes induced by changing the RCS temperature are driven by the magnitude and direction of the moderator reactivity feedback. For example, the moderator temperature coefficient (MTC) is negative throughout most of the fuel cycle and thus acts to increase the total reactivity of the reactor core, i.e. reactor power, as the RCS temperature decreases. Finally, the fuel Doppler coefficient also plays a minor role in the determination of the transient core power response because the reactivity feedback caused by the heating of the fuel inherently limits the power peaking.

The consequences of an SUIL event would be mitigated by operating RCPs or residual heat removal (RHR) pumps, which would remain operational throughout the event to transfer energy from the fuel to the reactor coolant. Although the RCS temperature and pressure transients would be limited by the operation of RCS and main steam (MS) pressure relief valves, the power excursion would ultimately be terminated by either (a) the addition of negative reactivity from the safety control rod banks due to a reactor trip, (b) aborting the RCP start-up, or (c) manual initiation of safety injection. A reactor protection signal and reactor trip would be generated by one of the following reactor trip system (RTS) functions: source range neutron flux, power range neutron flux (low setpoint), power range neutron flux (high setpoint), overtemperature delta-T, overpower delta-T, loss of flow, or manual reactor trip.

After operator or automatic action to stabilize the RCS conditions, sensible and decay heat would be removed by steaming to the condenser through the steam bypass system, to the atmosphere through the MS power operated relief valves (PORVs) or the main steam safety valves (MSSVs), or any combination of the three methods. However, the desirability of a given method is based on system availability and the extent to which the fission product barriers have been compromised. In all scenarios, feedwater would remain available to the steam generators from the auxiliary feedwater (AFW) system to replenish the secondary coolant. At this point in the transient, the reactor operators or automatic control systems would function to maintain the plant at shutdown conditions.

14.2.6.2 **Accident Evaluation**

An SUIL event is defined as an uncontrolled reduction in coolant temperature or boron concentration in the region of the core resulting from either the start-up of an RCP on an idle loop (loop stop valves open case), or recirculation through a loop stop valve bypass line on an isolated (loop stop valves closed case) loop, when a reduced coolant temperature or boron concentration exists in the idle (or isolated) loop. A loop is considered idle when its hot and cold leg loop stop valves are open, but the RCP on the loop is not operating. The ultimate goal of the accident analysis is to demonstrate that a DNB condition is not reached during the accident and, hence, fuel failure is not predicted to occur.

A high level of confidence that a DNB condition will not be reached is demonstrated by consideration of the Technical Specification requirements for loop stop valve operation, and for filling drained and isolated loops. Technical Specifications and associated procedures ensure that the preconditions necessary for significant reactivity insertion during an SUIL event (i.e., reduced temperature and boron concentration in an isolated or idle loop) cannot be achieved under credible circumstances.

A calculation has been performed to verify that an SUIL event with the maximum credible temperature differential between an idle loop and the active portion of the RCS at COLD SHUTDOWN or REFUELING SHUTDOWN will not result in complete loss of shutdown margin. This calculation is described in Section 14.2.6.2.4. In addition, a calculation was performed to determine the reactivity insertion rate and time to loss of shutdown margin assuming isolated loop recirculation is being performed with 0 ppm boron in the isolated loop. This calculation is described in Section 14.2.6.2.5.

14.2.6.2.1 Loop Configurations Permitted by Technical Specifications

The Technical Specifications permit the following RCS and RHR loop configurations to be achieved:

1. Two RCS Loops Operating, and One RCS Loop Idle (Unisolated)
2. Two RCS Loops Operating, and One RCS Loop Isolated
3. One RCS Loop Operating, and Two RCS Loops Idle (Unisolated)
4. One RCS Loop Operating, One RCS Loop Idle (Unisolated), and One RCS Loop Isolated

5. One or Two RHR Loops Operating, Three RCS Loops Idle (Unisolated)
6. One or Two RHR Loops Operating, Two RCS Loops Idle (Unisolated), and One RCS Loop Isolated
7. One or Two RHR Loops Operating, One RCS Loop Idle (Unisolated), and Two RCS Loop Isolated
8. Two RHR Loops Operating, Three RCS Loops Isolated

In cases 1 through 4, RHR may or may not be in operation. Of the above configurations, only those with an idle, unisolated loop are possible loop configurations for the loop stop valve open case (i.e., configurations 1, 3, 4, 5, 6, and 7). Similarly, only configurations 2, 4, 6, 7, and 8 are possible loop configurations for the loop stop valves closed case. As described below, achievement of these configurations in combination with a reduced idle (or isolated) loop temperature and reduced boron concentration would involve a non-credible combination of operator errors.

14.2.6.2.2 Procedural Requirements for Returning Isolated and Filled Loops to Service

To preclude the possibility of inadvertent reactivity insertion due to boron concentration or temperature mismatch between isolated and active portions of the RCS, Technical Specification 3.17 establishes requirements for loop stop valve operations:

1. Loop stop valves must remain open except during COLD SHUTDOWN or REFUELING SHUTDOWN. (An exception is made for short-term maintenance activities.)
2. When a reactor coolant loop is isolated, the loop stop valves must be de-energized, and their circuit breakers must be locked open.
3. An operable source range nuclear instrumentation channel with audible indication must be continuously monitored when returning an isolated loop to service. The loop stop valves must be closed if the source range count rate doubles.
4. Before opening the hot leg loop stop valve, the boron concentration in the isolated loop must be verified to be greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active volume of the Reactor Coolant System.
5. Before opening a cold leg loop stop valve, the hot leg loop stop valve must be open, and a relief line flow rate of at least 125 gpm must be established for at least 90 minutes. This time period and flow rate is sufficient to equilibrate the boron concentration and temperature of the isolated and active portions of the RCS. Further, the cold leg temperature of the isolated loop must be verified to be at least 70°F, and within 20°F of the highest cold leg temperature of the active loops. Verification of this condition must be completed within 30 minutes prior to opening the cold leg loop stop valve in the isolated loop. Finally, the boron concentration of the isolated loop must be greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active volume of the Reactor Coolant System.

Concerning the above requirements for loop stop valve operation, the Basis for Technical Specification 3.17 states: "The return to service of an isolated and filled loop is done in a controlled manner that virtually precludes the possibility of an uncontrolled positive reactivity addition from cold water or boron dilution." The recirculation activity described above is performed under strict administrative controls. Therefore, this activity itself does not constitute a boron dilution event.

14.2.6.2.3 Procedural Requirements for Filling Isolated and Drained Loops

In order to return an isolated and drained loop to service, Technical Specification 3.17 requires that the following conditions be met:

1. The isolated loop must be verified to be drained. Verification must be completed within 2 hours prior to partially opening the hot or cold leg loop stop valve in the isolated loop.
2. The RCS level must be at least 18 feet during the opening of the loop stop valves and during filling of the isolated loop. This requirement is established to ensure that the RCS water level does not drop below mid-nozzle level, thereby ensuring adequate suction conditions for the RHR pumps.
3. A source range nuclear instrument channel is required to be monitored to detect any unexpected positive reactivity addition.

Concerning the return of isolated and drained loops to service, the Basis for Technical Specifications 3.17 states: "An initially isolated and drained loop may be returned to service by partially opening the cold leg loop stop valves and filling the loop in a controlled manner from the Reactor Coolant System. To eliminate numerous reactor coolant pump jogs to completely fill a drained loop, a partial vacuum may be established in the isolated loop prior to commencing filling from the active volume of the Reactor Coolant System. The vacuum-assist loop fill evolution requires initiating seal injection to the reactor coolant pump to permit establishing an adequate vacuum in the isolated loop. A portion of the reactor coolant pump seal injection enters the isolated loop. To eliminate the reactivity concerns associated with the water injected into the isolated and drained loop from the seal injection, a water source of known boron concentration is used."

By returning isolated and drained loops to service in the manner described above, achievement of reduced idle loop temperature and reduced boron concentration would involve a non-credible combination of operator errors.

14.2.6.2.4 Inactive Loop Start-Up with Temperature Mismatch

A bounding calculation has demonstrated that an SUIL event with the maximum credible temperature differential between an idle loop and the active portion of the RCS during COLD SHUTDOWN or REFUELING SHUTDOWN will not result in complete loss of shutdown margin. This calculation assumes that the boron concentration in the idle loop is equal to the concentration in the active portion of the RCS, but that the idle loop temperature is 150°F lower than the active portion of the RCS. Based on this calculation, it is concluded that the reactivity insertion driven only by temperature differential will not result in erosion of SDM, power excursion, or reduction in margin to a DNB condition. Development of a significant boron concentration differential between an idle loop (i.e., loop stop valves open) and the active portion of the RCS is not considered credible.

14.2.6.2.5 Isolated Loop Recirculation with Boron Mismatch

The start-up of an inactive reactor coolant loop with the loop stop valves initially closed has been analyzed. The analysis assumes the inactive loop is at a boron concentration of 0 ppm, while the active portion of the system is at 1500 ppm, a conservatively high value for the beginning of core life. The flow through the relief line is assumed to be at its maximum value of 400 gpm. Even with the assumption that administrative procedures are violated to the extent that an attempt is made to open the loop stop valves with 0 ppm in the inactive loop while the remaining portion of the system is at 1500 ppm, the dilution of the boron in the core region is slow. The initial reactivity insertion rate is calculated to be 3.2×10^{-5} Δk/sec, considerably less than the reactivity insertion rates considered in the Rod Withdrawal at Power and Rod Withdrawal at Subcritical accident analyses. The operator will recognize a high source range count rate signal, and will terminate the dilution by turning off the pump in the inactive loop or by borating to counteract the dilution.

14.2.6.3 **Conclusion**

The Technical Specifications and associated procedural requirements for unisolation of an isolated loop ensure with a high degree of confidence that the RCS and RHR loop configurations presented above cannot achieve the preconditions (i.e., boron concentration and temperature in the isolated loop) necessary for a significant reactivity insertion due to unisolated loop start-up. The recirculation activity which constitutes the loop stop valves closed case is an operating procedure performed under strict administrative control, and does not by itself constitute a reactivity insertion accident. An SUIL event with the maximum credible temperature differential (and no boron concentration differential) between an idle loop and the active portion of the RCS will not result in complete loss of shutdown margin.

14.2.7 Excessive Heat Removal Due to Feedwater System Malfunctions

14.2.7.1 **Identification of Causes and Accident Description**

Reductions in feedwater temperature or additions of excessive feedwater can result in an increase of core power above full power. Such transients are attenuated by the thermal capacity in the secondary plant and in the reactor coolant system. The overpower overtemperature protection (nuclear overpower and delta T trips) prevents any power increase that could lead to a DNBR of less than the applicable SAL (Section 3.2.3).

A feedwater temperature reduction and subsequent reactor coolant system load increase can be initiated by any of the following events: the inadvertent opening of a high-pressure feedwater heater bypass valve which diverts flow around a first-point feedwater heater, the inadvertent opening of a low-pressure feedwater heater bypass valve which diverts flow around the second-, third-, and fourth-point feedwater heaters, or the isolation of extraction steam to the first-point feedwater heaters. Inadvertent bypass valve opening or extraction steam isolation results in a sudden reduction in feedwater inlet temperature to the steam generators. The increased subcooling creates a greater load demand on the RCS. The feedwater heater bypass valves can only be opened manually.

A second example of excessive heat removal is a transient associated with the accidental full opening of feedwater regulating and bypass valves in one or more steam generator loops due to control system malfunction or operator error. The sudden increase in feedwater flow would increase the subcooling of the primary system resulting in a higher core power due to reactivity feedback.

14.2.7.2 **Method of Analysis**

The feedwater temperature reduction event is evaluated by determining a conservative feedwater temperature reduction for the initiating events described in Section 14.2.7.1. The resulting feedwater temperature reduction from each initiating event is shown to be less than the temperature reduction required to generate a primary system load increase of 10% of full power. The event was explicitly analyzed at 2546 MWt for a bounding, 60°F feedwater temperature reduction with the transient analysis code RETRAN (Reference 12), which simulates the reactor coolant system, core kinetics, and the feedwater and steam systems. DNBR analysis for the SIF product was performed with the thermal-hydraulic code COBRA (Reference 13) or the VIPRE-D code (Reference 36) for the 15 x 15 Upgrade fuel design. The analysis incorporates the Statistical DNBR Evaluation Methodology (Reference 17).

The feedwater temperature reduction transient analysis was performed at nominal values consistent with steady-state full power operation: initial pressurizer pressure of 2250 psia, RCS average temperature of 573°F, and full power at 2546 MWt. The use of nominal conditions is consistent with the Virginia Power Statistical DNBR Methodology (Reference 17). The limiting case had a Doppler temperature coefficient of -1.2 pcm/°F, a moderator temperature coefficient of -45 pcm/°F, and automatic rod control enabled.

A DNBR penalty of 3.0% will be applied to account for the increased bypass flow due to the conversion to upflow configuration. This DNBR penalty is conservative and applicable to all DNB events and will be deducted from the retained margin for the Westinghouse 15x15 Upgrade fuel product during the core reload thermal-hydraulic evaluation in accordance with NRC approved methodology in VEP-NE-2-A (Reference 17).

Excessive feedwater addition due to a feedwater control system malfunction or operator error, which allows a feedwater control valve to open fully, was also explicitly analyzed. The analyses were performed using the transient simulation code RETRAN. The excessive feedwater flow transient was analyzed for the 15 x 15 SIF product using deterministic conditions consistent with steady-state full power operation to allow for calibration and instrument errors.

In the 15x15 Upgrade statistical DNBR submittal using VIPRE-D to the NRC (Reference 37), it was stated that the Feedwater malfunction event would be analyzed using statistical methods. With NRC approval (Reference 38) of the LAR in Reference 37, the excessive feedwater flow transient will be analyzed using statistical conditions for the 15 x 15 Upgrade fuel design.

The maximum capacity of the feedwater pumps at Surry is no more than 125% of nominal full power flow. However, the excess feedwater transient was analyzed at 125%, 150%, and 200% of nominal flow. The multi-loop cases assumed equal flows in all three secondary loops. The analyses show that the multi-loop transients experience a lower DNBR than the corresponding single-loop cases. Transients with automatic rod control were shown to have a slightly lower DNBR than the manual rod control cases. The limiting case is the multi-loop analysis with 150% feedwater flow and automatic rod control.

The ability of the automatic rod control system to withdraw rods from the core has been eliminated. This prevents addition of positive reactivity by rod withdrawal in response to transient event conditions thereby resulting in lower power during the event. The event cases with automatic rod control are retained herein, even though they are not credible, as they continue to bound the current plant design.

14.2.7.3 **Results**

14.2.7.3.1 Excessive Feedwater Flow Transient

Figures 14.2-17 through 14.2-21 show the multiple loop 150% feedwater transient with reactor control. The positive reactivity feedback from the sudden increase of feedwater at 0.001 second results in an increase of core power which levels off at 106% of 2546 MWt at about 22 seconds into the transient. The excessive feedwater addition to the steam generators causes an overcooling of the reactor coolant system, resulting in a decrease in pressurizer pressure and RCS average temperature. The analysis results demonstrate that no rods have a calculated MDNBR less than the applicable SAL listed in Section 3.2.3. The mismatch between feedwater flow and steam flow causes the steam generator level to rise until the SG high-high level setpoint is reached, actuating feedwater isolation at 115 seconds. With the feedwater flow reduced to zero, the primary system heats up causing a rise in RCS temperature and pressurizer pressure and a decrease in core power due to negative moderator temperature feedback. The steam generator inventories continue to boil off to dissipate the core power that is still being generated. Eventually, the SG inventory drops to the low-low level setpoint, tripping the reactor at 207 seconds, followed by a turbine trip 2 seconds later.

14.2.7.3.2 Feedwater Temperature Reduction Event

The feedwater temperature reduction event was analyzed with RETRAN and VIPRE-D computer code (Reference 36) for the 15 x 15 Upgrade fuel design for a 200-second duration, which was adequate to demonstrate a new steady-state condition well beyond the point of the event minimum DNBR. Feedwater temperature reduction, normalized nuclear power, change in pressurizer pressure, change in RCS loop ΔT and change in RCS average temperature as a function of time are illustrated in Figures 14.2-22 through 14.2-26. The reduction in feedwater temperature causes a cooldown of the reactor coolant system resulting in a decrease in coolant average temperature and pressurizer pressure. The reduction in coolant average temperature results in an increase in core power from the large negative moderator temperature coefficient present at end of cycle. This increase in core power balances the RCS cooldown so that the system reaches a new steady-state condition at 109% of 2546 MWt, with T_{avg} 2.3°F below nominal and RCS loop ΔT 5.7°F above nominal. The reactor does not trip under these conditions. Pressurizer pressure decreases to 25.6 psi below nominal before recovering due to pressurizer heater actuation. The analysis results demonstrate that no rods have a calculated MDNBR less than the applicable SAL listed in Section 3.2.3. Analysis results confirm that the excessive load increase event evaluated in Section 14.2.8 is more limiting with respect to DNBR.

14.2.7.3.3 Excessive Feedwater Flow Hot Zero Power

Multiple loop excessive flow malfunction is not considered credible at no load conditions. The Feedwater Control System (FWCS) would be in manual mode at start-up and low power. Thus, a series of operator actions inadvertently opening the main and bypass control valves in more than one loop simultaneously would be extremely improbable. At full power, the FWCS is in automatic and a multiple loop control system malfunction becomes more credible. However, the possibility of single loop malfunction at hot zero power has been considered and is discussed below.

The reactivity insertion rate at no load following an excessive feedwater accident has also been calculated, with the following assumptions:

1. A step increase in feedwater flow to one steam generator from 0 to the nominal full-load flow.
2. The most negative reactivity moderator coefficient at the end of life. The value used in the calculation was for a rodded core. The value when just critical at no load will be less negative.
3. A constant feedwater temperature of 70°F.
4. Neglect of the heat capacity of the reactor coolant system and the thick metal of the steam generator shell.
5. Neglect of the energy stored in the fluid of the unaffected steam generators.

The maximum reactivity insertion rate was calculated to be 3.9×10^{-4} delta k/sec, which is less than the maximum reactivity insertion rate analyzed in Section 14.2.1, *Uncontrolled Control-Rod Assembly Withdrawal From a Subcritical Condition*. It should be noted that if the incident occurs with the unit just critical at no load, the reactor may be tripped by the power range flux level trip at a low setting (approximately 25%). As shown in Section 14.2.1 there is a large DNB margin with the above-calculated reactivity insertion rate.

The continuous addition of cold feedwater after a reactor trip is prevented since the reduction of the reactor coolant system temperature, pressure, and pressurizer level leads to the actuation of safety injection on low-low pressurizer pressure. The safety injection signal trips the main feedwater pumps and closes the feedwater pump discharge valves as well as the main feedwater control valves.

14.2.7.4 **Conclusions**

Primary system load increase due to the inadvertent opening of a feedwater heater manual bypass valve or the isolation of extraction steam to both first-point feedwater heaters is bounded by that assumed for the excessive load increase event presented in Section 14.2.8. The excessive load increase event evaluates the consequences of a 10% step load increase from full power. The feedwater temperature reduction event is shown to be bounded by the excessive load increase event.

Representative transient results for excessive load increases due to reduced feedwater temperature and excessive feedwater flow indicate that a core power increase is accompanied by a reactor coolant system average temperature decrease. This has the effect of maintaining an adequate margin to the applicable SAL (Section 3.2.3). It has been shown that the maximum reactivity insertion rate that occurs at no load following excessive feedwater addition is less than the maximum value considered in the analysis of a control rod assembly withdrawal incident from a subcritical condition. It has further been shown that automatic action occurs to prevent the continuous addition of cold feedwater after a unit trip. The event acceptance criteria (DNBR greater than the applicable SAL, reactor coolant system and main steam system pressures less than 110% of design limits, no event propagation) are satisfied for the feedwater malfunction that results in either an increase in feedwater flow or a decrease in feedwater temperature.

14.2.8 Excessive Load Increase Incident

An excessive load increase (ELI) incident is defined as a rapid increase in steam generator flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step-load increase or a 5% per minute ramp-load increase, without a reactor-trip, in the range of 15% to 100% of full power. Any loading rate in excess of these values may cause a reactor trip to be actuated by the reactor protection system. If the load increase exceeds the capability of the reactor control system, the transient is terminated in sufficient time to prevent the DNBR from being reduced below the SAL (Section 3.2.3), since the core is protected by the combination of the nuclear overpower and the overpower-overtemperature trips discussed in Chapter 7, although the analysis conservatively does not credit the latter trip. An excessive load increase incident could result from either an administrative violation, such as excessive loading by the operator, or an equipment malfunction in the steam bypass control or turbine speed control.

For excessive loading by the operator or by system demand, the turbine load limiter keeps the maximum turbine load from exceeding 100% rated load.

During power operation, steam bypass to the condenser is controlled by reactor coolant condition signals; high reactor coolant temperature indicates a need for steam bypass. A single controller malfunction does not cause steam bypass; an interlock blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

14.2.8.1 **Method of Analysis**

Three cases were analyzed to demonstrate the unit behavior for a 10% step increase from 2546 MWt. The first two cases were at end-of-life (EOL) conditions, when the moderator temperature coefficient (MTC) for the core is assumed to be at its most negative limit of -45 pcm/°F, with and without automatic rod control. The third case was at beginning-of-life (BOL), with the MTC at its least negative limit of 0.0 pcm/°F and automatic rod control. Previous analyses indicate that a BOL case without automatic rod control is bounded by the other cases. The analyses were performed using the RETRAN code to provide a detailed simulation of the RCS, core kinetics, and the feedwater and steam systems. Following the RETRAN calculation of the RCS transient initiated from nominal conditions, the VIPRE-D computer code was used to compute the MDNBR at the limiting statepoints for the 15 x 15 Upgrade fuel design from the RETRAN forcing functions as a function of time.

A DNBR penalty of 3.0% will be applied to account for the increased bypass flow due to the conversion to upflow configuration. This DNBR penalty is conservative and applicable to all DNB events and will be deducted from the retained margin for the Westinghouse 15x15 Upgrade fuel product during the core reload thermal-hydraulic evaluation in accordance with NRC approved methodology in VEP-NE-2-A (Reference 17).

The ability of the automatic rod control system to withdraw rods from the core has been eliminated. This prevents addition of positive reactivity by rod withdrawal in response to transient event conditions thereby resulting in lower power during the event. The event cases with automatic rod control are retained herein, even though they are not credible, as they continue to bound the current plant design.

14.2.8.2 **Results**

Figures 14.2-27, 14.2-28, 14.2-29, and 14.2-30 illustrate the results of the ELI transient with the reactor in manual control at EOL conditions, while Figures 14.2-31, 14.2-32, 14.2-33, and 14.2-34 represent the same event under automatic control. As expected, in the manual control case the decrease in RCS pressure and temperature is much more pronounced due to the high moderator temperature feedback. Under automatic control, rod movement will significantly retard the decrease in pressure and temperature. The nuclear power levels off at approximately 110% of 2546 MWt in both cases to balance the steam flow; but it does so sooner under automatic control. The transient DNBR decreases initially and flattens out as the power equilibrium is reached. Rod control has only a minimal effect on the magnitude of the minimum DNBR.

The third case, at BOL under automatic control with enhanced rod worth, is represented in Figures 14.2-35, 14.2-36, 14.2-37, and 14.2-38. The behavior is similar to that of the second case above. As the moderator feedback is assumed to be negligible at BOL, the reactivity to counteract the overcooling effect comes entirely from the control rods. Although RCS pressure and temperature drop initially, they recover and rise to a comparable level later in the transient, and are expected to reach an equilibrium, if the transient is followed long enough.

14.2.8.3 **Conclusions**

The three cases analyzed have considerable margin to the applicable SAL (Section 3.2.3). It is concluded that unit integrity is maintained throughout lifetime for the excessive load increase incident.

14.2.9 Loss of Reactor Coolant Flow

14.2.9.1 **Flow Coastdown Incidents**

A loss-of-coolant-flow incident can result from a mechanical or electrical failure in a reactor coolant pump or from an interruption in the power supply to these pumps. If the reactor is at power at the time of the incident, the immediate effect is a rapid increase in coolant temperature.

This increase could result in DNB with subsequent fuel damage if the reactor is not tripped promptly. The following trip circuits provides the necessary protection against any loss-of-coolant-flow incident:

1. Low reactor coolant flow.
2. Reactor Coolant Pump motor circuit breaker opening,
3. Low voltage on pump power supply busses, and
4. Low frequency on pump power supply busses (opens RCP supply breakers).

Of these, only the low reactor coolant flow reactor trip is assumed in the analysis. The low frequency and low voltage signals are not credited for reactor protection, but are assumed to trip the RCPs at their appropriate setpoints. They provide diverse backup protection for loss of flow accidents. Even though these reactor protection system inputs do not meet IEEE-279 requirements, no credible failure mechanism has been identified which would impact the operability of the reactor protection system.

The reactor trip setpoints and their redundancy are further described in UFSAR Section 7.2, *Reactor Protection System*.

The simultaneous loss of electric power to all reactor coolant pumps at full power is the most severe credible loss-of-coolant-flow condition. For this condition, reactor trip together with flow sustained by the inertia of the coolant and rotating pump parts will be sufficient to prevent reactor coolant system overpressure and the DNBR from being reduced below the applicable SAL (Section 3.2.3).

The following discussion presents the loss-of-flow analysis performed for operation at 2546 MWt. This analysis does not include cases for two loop operation.

14.2.9.1.1 Method of Analysis

The two limiting cases that were analyzed are as follows:

1. Loss of three out of three RCPs from a power level of 2546 MWt, due to an undervoltage condition.
2. Loss of three out of three RCPs from a power level of 2546 MWt, due to a frequency decay condition (-5 Hz/sec).

Partial losses of flow from the loss of fewer than three reactor coolant pumps are protected by the same low flow reactor trip. Because of the identical protection setpoint, and correspondingly higher coolant flow rates throughout the transient, the partial loss of flow events are less limiting than the complete loss of flow events. Therefore, the partial loss of flow events are bounded by the complete loss of flow analyses and no specific partial loss of flow analyses are run.

The above analyses assume core characteristics associated with the 15 x 15 SIF fuel product. The analysis incorporates the *Statistical DNBR Evaluation Methodology* (Reference 17).

The normal power supplies for the pumps are three buses supplied by the generator. Each bus supplies power to one pump. When a generator trip occurs, the pumps are automatically transferred to a bus supplied from external power lines, and the pumps continue to supply coolant flow to the core. The simultaneous loss of power to all reactor coolant pumps is a highly unlikely event. Following any turbine trip, where there are no electrical faults that require tripping the generator from the pump supply network, the generator remains connected to the network for approximately 30 seconds. The reactor coolant pumps remain connected to the generator, thus ensuring full flow for approximately 30 seconds after the reactor trip before any transfer is made. Since each pump is on a separate bus, a single-bus fault would not result in the loss of more than one pump.

A full unit simulation with RETRAN (Reference 12) is used in the analysis to compute the core average and hot-spot heat flux transient responses, including flow coastdown, temperature, reactivity, and control-rod assembly insertion effects.

These data are then used in a detailed thermal-hydraulic computation to compute the DNB margin. This computation solves the continuity, momentum, and energy equations of fluid flow, together with the WRB-1 DNB correlation discussed in Section 3.4.2. The assumptions made in the calculations are discussed below. The VIPRE-D computer code was used to compute the MDNBR and DNBR margin for the LOFA statepoint for the 15 x 15 Upgrade fuel design using the initial conditions specified in 14.2.9.1.2.

A DNBR penalty of 3.0% will be applied to account for the increased bypass flow due to the conversion to upflow configuration. This DNBR penalty is conservative and applicable to all DNB events and will be deducted from the retained margin for the Westinghouse 15x15 Upgrade fuel product during the core reload thermal-hydraulic evaluation in accordance with NRC approved methodology in VEP-NE-2-A (Reference 17).

14.2.9.1.2 Initial Operating Conditions

The initial conditions which are assumed in the analysis are presented below. They are consistent with the statistical treatment of key analysis parameters for the 15 x 15 SIF analysis. (See Section 3.4.3.2).

1. Key thermal/hydraulic parameters used in analysis - 3 loops operating - 15 x 15 SIF:

Power	2546 MWt
Pressure	2249.7 psia
Inlet Temperature	541.9°F
Minimum Measured Flow	273,000 gpm

2. Thermal/Hydraulic Conditions used for the analysis of 15 x 15 Upgrade Fuel Design

Power	2589.3 MWt
Pressure	2250.0 psia
Inlet Temperature	540.7°F
RCS Flow Rate	273,000 gpm

14.2.9.1.3 Reactivity Coefficients

A least negative Doppler Temperature Coefficient (-1.0 pcm/°F) and most positive Moderator Temperature Coefficient (+6 pcm/°F) were assumed since these result in higher heat flux at the time of minimum DNBR. The sensitivity to the effective delayed neutron fraction was evaluated. A minimum delayed neutron fraction was used because it produced the most limiting DNBR.

14.2.9.1.4 Reactor Trip

Following the loss of flow induced by underfrequency or undervoltage, the reactor is assumed to trip on low flow in any loop. This trip meets the IEEE-279 criterion and therefore cannot be negated by a single failure. Neither the low voltage nor low frequency trip circuits meet the IEEE-279 criterion from sensor to trip and are therefore considered backup trips. The low flow trip setting is 90% of full loop flow; the trip signal is assumed to be initiated at 87% of minimum measured flow, allowing 3% for instrumentation errors. It is also assumed that, upon reactor trip, the most reactive control rod assembly is stuck in its fully withdrawn position, resulting in a minimum insertion of negative reactivity. The assumed trip reactivity was 4.0% $\Delta k/k$, which is confirmed to be bounding for each reload cycle.

14.2.9.1.5 Flow Coastdown

Reactor coolant flow coastdown curves for the limiting undervoltage and underfrequency induced loss of flow accidents are shown in Figures 14.2-39 and 14.2-40, respectively. The flow profile for the undervoltage transient includes an initial 2% flow penalty to account for the potential of a “back EMF” phenomenon prior to the trip of the RCP. The RCP will maintain flow at or above 98% for undervoltage conditions less severe than the undervoltage trip setpoint. This is modeled by a prompt drop in flow from 100% to 98% of minimum measured flow followed by a five second delay prior to the RCP trip on (undervoltage). The reactor is not assumed to trip until the low flow setpoint has been reached.

14.2.9.1.6 Results

Both the underfrequency and the undervoltage trip events were analyzed. The two events were found to have nearly identical values of minimum DNBR. The minimum DNBRs for the two accidents showed a considerable margin to the applicable SAL (Section 3.2.3).

The transient responses of power, inlet temperature, average temperature, and pressurizer pressure are plotted in Figures 14.2-41 through 14.2-44 for the undervoltage case and 14.2-45 through 14.2-48 for the underfrequency case.

14.2.9.1.7 Conclusions

The analyses performed have demonstrated that for the above loss of flow incidents, the DNBR does not decrease below the applicable SAL (Section 3.2.3) at any time during the transient. Thus, no fuel or clad damage is predicted, and all applicable acceptance criteria are met.

14.2.9.2 **Locked Rotor Incident**

14.2.9.2.1 Identification of Causes and Accident Description

The Locked Rotor/Sheared Shaft events are characterized by the rapid loss of forced circulation in one Reactor Coolant System (RCS) loop. A Locked Rotor event is defined as the seizure of a Reactor Coolant Pump (RCP) motor due to a mechanical failure. The Sheared Shaft event is defined as the separation of the RCP impeller from the motor due to the severance of the impeller shaft. For both the Locked Rotor and the Sheared Shaft events, the postulate RCP failure causes the reactor coolant flow rate to decrease more rapidly than a normal RCP coastdown.

During power operation the reduction in RCS flow caused by a Locked Rotor or Sheared Shaft event results in degradation of the heat transfer between the fuel and the reactor coolant, and between the reactor coolant and the secondary coolant in the steam generator (SG). As a result of the reduced fluid velocity, the core differential (ΔT) and average temperatures (T_{avg}) increase. The reduced heat transfer to the secondary fluid also contributes to the reactor coolant temperature increase. The expansion of the RCS fluid that accompanies the temperature increase causes an insurge of coolant into the pressurizer, and thus an increase in the reactor coolant system pressure. The reduced fluid velocity and subsequent temperature rise also act to reduce the heat transfer from the fuel, causing the fuel temperature to increase. Fuel damage could then result if specified acceptable fuel damage limits are exceeded during the transient, i.e., if the fuel experiences a Departure from Nucleate Boiling (DNB). Due to the severe nature of these postulated failures, there is a possibility that a limited number of fuel rods will experience DNB. Thus, timely actuation of the Reactor Protection System (RPS) is required to help limit the number of potential fuel failures.

The immediate core power response during a Locked Rotor or Sheared Shaft event will change in accordance with the RCS temperature and pressure based on the magnitude and direction of the moderator reactivity feedback. As such, a Locked Rotor or Sheared Shaft event occurring in the presence of a positive Moderator Temperature Coefficient (MTC) will see an increase in core power at the RCS temperature increases. Conversely, the presence of a negative MTC will cause the core power to decrease as the RCS temperature increases. If the Rod Control System is in automatic, movement of the control rods will generally be in a direction such that a power reduction occurs.

The core power response is also influenced by the magnitude of the fuel Doppler coefficient. The reduced capability of the reactor coolant to remove energy from the reactor core causes the fuel temperature to increase. In the presence of a negative fuel Doppler coefficient, a fuel temperature increase contributes negative reactivity to the core, which acts to diminish the core power increase.

The potential for a Locked Rotor or Sheared Shaft event is present during all modes of operation where at least one RCP is functioning to provide forced circulation. However, the consequences of a Locked Rotor or Sheared Shaft event are reduced dramatically when the reactor is not at power. During subcritical or zero power operation, natural circulation is more than adequate to remove decay heat following the loss of forced circulation. Thus, the potential for exceeding the specified fuel design limits is nearly zero when the reactor is not at power.

Maintaining the fuel cladding integrity is a primary concern for the Locked Rotor/Sheared Shaft event, although integrity may not be maintained for all fuel rods. Therefore, maintaining the RCS as a fission product barrier becomes more significant. Specifically, RCS integrity may be challenged as a result of the volumetric expansion of the fluid caused by the heating of the RCS fluid. Operation of the pressurizer sprays and Power Operated Relief Valves (PORVs) can help limit the impact of the subsequent pressure increase, but cannot counteract the volumetric expansion of the RCS fluid. In general, the short duration of the Locked Rotor event acts in concert with the functioning of the Pressurizer Safety Valves (PSVs), to prevent excessive RCS pressurization. Thus, timely actuation of the RPS is also required to help limit the RCS pressure response.

Sensible and decay heat can be removed by steaming to the condenser through the steam bypass system, to the atmosphere through the Main Steam (MS) PORV or the Main Steam Safety Valves (MSSVs), or any combination of the three methods. However, the desirability of a given method is based on system availability and the extent to which the fission product barriers have been compromised. In all scenarios, feedwater remains available to the Steam Generators (SGs) from either the Main Feedwater (MFW) System or the Auxiliary Feedwater (AFW) System to replenish the secondary coolant. Shortly after the reactor is shut down, the energy removal capability of the SGs will exceed the RCS sensible and decay heat levels, and the reactor operators/automatic control systems will function to maintain the plant at the new equilibrium condition.

The use of the ZIRLO and Optimized ZIRLO (References 31 and 39) alloy in Surry fuel assemblies has a negligible effect on the number of rods in DNB or the peak RCS pressure, and has a negligible effect on the total Zirconium/water reaction compared to Zircaloy. Therefore, the analysis for the 15 x 15 SIF product or the 15 x 15 Upgrade fuel design remains applicable, and reanalysis of the locked rotor event was not required for the implementation of this cladding material.

14.2.9.2.2 Method of Analysis

14.2.9.2.2.1 General. To cover all applicable phases of plant operation, Locked Rotor and Sheared Shaft events during Cold Shutdown, Intermediate Shutdown, Hot Shutdown, Reactor Critical (manual rod control), and Power Operation (automatic and manual rod control modes) are considered. A transient analysis is only required for the Locked Rotor and Sheared Shaft events at full power with manual rod control. The results for a Locked Rotor or Sheared Shaft event at any of the remaining operating conditions are bounded by those of the full power manual rod control case.

Except where otherwise noted, the following assumptions are made in the Locked Rotor/Sheared Shaft transient analysis:

1. The DNB analysis employs a statistical treatment of key analysis uncertainties; the transient cases are initiated from the condition listed in Section 14.2.9.1.2.
2. The main steam and RCS overpressurization analyses employ a deterministic treatment of key analysis uncertainties (102% of 2546 MWt or 100.38% of 2587 MWt; nominal T_{avg} +4°F; nominal pressurizer pressure +30 psi; and Thermal Design Flow).
3. Reactor protection is assumed to be provided by the low coolant loop flow rate reactor trip at 87% of the applicable analysis flow rate. A 1.0-second trip delay is assumed.

4. The analysis supports a moderator temperature coefficient (MTC) core design limit of +6.0 pcm/°F from 0% to 50% power and a linearly decreasing limit to 0.0 pcm/°F at 100% power. The analysis is non-limiting at EOC.

5. Unaffected reactor coolant pumps were assumed to trip 2.0 seconds after reactor trip on low loop coolant flow. The inertia of the unaffected pumps was conservatively reduced by 10% from the design value.

6. In the DNB transient analyses, the turbine trip following reactor trip was conservatively assumed to not function. In the main steam and RCS overpressurization transient analyses, the turbine trip following reactor trip was conservatively assumed to actuate.

7. Manual rod control was assumed.

8. In the DNB transient analyses, the pressurizer sprays and PORVs are conservatively assumed to be operable. In the main steam and RCS overpressurization transient analyses, the pressurizer sprays and PORVs are conservatively assumed to not actuate.

9. The RCS overpressurization analysis assumes 50% bypass flow. The high degree of bypass flow in the overpressurization cases compensates for the uncertainty associated with the thermal/hydraulic behavior of the core due to coolant voiding during a locked rotor event.

14.2.9.2.2.2 Transient Analysis for DNB. The transient analysis for DNB considerations utilizes the RETRAN transient analysis code (Reference 12) and the VIPRE-D detailed core thermal/hydraulics code (Reference 36). The WRB-1 critical heat flux correlation (Reference 30) is used in the analysis.

The transient analysis for DNB is performed to determine the number of fuel pins that experience DNB as a result of a Locked Rotor or Sheared Shaft event. A fuel pin is assumed to fail if the predicted MDNBR is less than the applicable SAL (Section 3.2.3). The Locked Rotor DNB event scenario is therefore designed to produce the most limiting DNB response. From an analytical perspective, this goal is achieved by choosing initial conditions and analysis assumptions that will maximize coolant temperature and the power-to-flow ratio and minimize pressure during the event.

The analysis results demonstrate that no rods have a calculated MDNBR less than the applicable SAL (Section 3.2.3). Therefore, no fuel damage is predicted to occur during the event. Figures 14.2-49 through 14.2-51 provide transient results for core inlet mass flow rate, core heat flux and core inlet temperature from the limiting DNBR analysis case.

A DNBR penalty of 3.0% will be applied to account for the increased bypass flow due to the conversion to upflow configuration. This DNBR penalty is conservative and applicable to all DNB events and will be deducted from the retained margin for the Westinghouse 15x15 Upgrade fuel product during the core reload thermal-hydraulic evaluation in accordance with NRC approved methodology in VEP-NE-2-A (Reference 17).

14.2.9.2.2.3 Transient Analysis for RCS and Main Steam Overpressurization. The transient analysis for RCS and main steam overpressurization considerations also utilizes the RETRAN transient analysis code. The transient analysis for overpressurization considerations verifies that the peak RCS pressure (intact cold leg pump exit pressure) and peak main steam pressure (intact loop steam generator pressure) remain below 110% of RCS and main steam design pressure (2750 psia and 1210 psia, respectively). The Locked Rotor overpressurization event scenario is designed to produce the most limiting overpressurization response. From an analytical perspective, this goal is achieved by choosing initial conditions and analysis assumptions that will minimize RCS energy removal and maximize core coolant expansion during the transient.

Figures 14.2-52 and 14.2-53 provide transient results for RCS pressure and steam generator pressure from the limiting pressurization analysis cases.

14.2.9.2.3 Conclusions

For the scenarios for which a transient analysis was performed, the following conclusions are applicable:

1. Acceptable offsite dose consequences are ensured, since the analysis demonstrates that the fraction of fuel rods predicted to experience Departure from Nucleate Boiling (DNB) is less than that which provides acceptable offsite dose analysis results.
2. Reactor Coolant System (RCS) integrity is maintained throughout the transient as demonstrated by analysis of transient RCS pressure. Specifically, the maximum RCS pressure, which occurred in the intact cold leg pump exit, remained below 2750 psia throughout the transient.
3. Main Steam System (MSS) integrity is maintained throughout the transient as demonstrated by analysis of transient MSS pressure. Specifically, the maximum main steam pressure, which occurred in the intact loop steam generator, remained below 1210 psia throughout the transient.

14.2.9.2.4 Environmental Consequences of Locked Rotor Accident (LRA)

The environmental consequences of the Locked Rotor Accident are not explicitly calculated for Surry Power Station. In accordance with RG 1.183 Appendix G.2., the dose consequences of the LRA are bounded by the MSLB analysis if no fuel damage is postulated for the limiting event. Fuel damage, defined as rods that experience departure from nucleate boiling (DNB), is not predicted during the design basis LRA transient analysis. As such, an analysis of the radiological dose consequences for the LRA event is not explicitly conducted for Surry Power Station.

14.2.10 Loss of External Electrical Load

14.2.10.1 **Identification of Causes and Accident Description**

The loss of external electrical load may result from an abnormal variation in network frequency or other adverse network operating conditions. It may also result from a trip of the turbine generator or the opening of the main breaker from the generator that fails to cause a turbine trip but causes a large, rapid nuclear steam supply system load reduction by the action of the turbine control.

The unit is designed to accept a step loss of load from 100% to 50% without actuating a reactor trip. The automatic steam bypass system, with 40% steam dump capacity to the condenser, is able to accommodate this load rejection by reducing the severity of the transient imposed on the reactor coolant system. The reactor power is reduced to the new equilibrium power level at a rate consistent with the capability of the rod control system. The pressurizer relief valves may be actuated, but the pressurizer safety valves and the steam generator safety valves do not lift for the 50% step loss of load with condenser steam dumps.

In the event the steam bypass (condenser dump) valves fail to open following a large load loss or in the event of a complete loss of load with the steam dump operating the steam generator safety valves may lift and the reactor may be tripped on a high pressurizer pressure, high pressurizer level, or overtemperature delta-T signal. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. The pressurizer safety valves and steam generator safety valves are, however, sized to protect the reactor coolant system and main steam systems, respectively, against all load losses, including a complete loss of steam load without the bypass system (condenser dumps) or atmospheric dumps (main steam PORVs) available. The steam dump valves will not be opened for load reductions of 10% or less. For larger load reductions they may open.

The most likely source of a complete loss of load on the nuclear steam supply system is a trip of the turbine generator. In this case, there is a direct reactor trip signal (unless below approximately 10% power) derived from either the turbine autostop oil pressure or a closure of the turbine stop valves. Reactor coolant temperatures and pressure do not significantly increase if the steam bypass system and pressurizer pressure control system are functioning properly. However, in this analysis, the behavior of the unit is evaluated for a complete loss of load from full power without direct reactor trip. The analysis, presented below, shows the adequacy of the pressure relieving devices to prevent Main Steam System and Reactor Coolant System overpressurization and to show that no fuel damage occurs. The latter is demonstrated by conservatively requiring that the applicable SAL (Section 3.2.3) is met for the hottest rod in the core.

As will be shown, the reactor coolant system and Main Steam System pressure relieving devices have sufficient capacities to ensure the safety of the unit without relying on the mitigating capabilities of the Automatic Rod Control, Pressurizer Pressure Control or Main Steam Bypass Systems.

14.2.10.2 **Method of Analysis**

The complete loss of load transients are analyzed with the Virginia Power RETRAN (Reference 12) and VIPRE-D detailed core thermal/hydraulics code (Reference 36) at the limiting statepoint.

The RETRAN model is used to perform the overall Reactor System transient analysis. The model describes the neutron kinetics, Reactor Coolant System including the pressurizer and pressurizer safety and relief valves and spray, and the Main Steam System including the steam generators and main steam safety valves. Outputs of the RETRAN analysis include reactor power level, temperatures and pressures at various points in the Reactor Coolant System, pressurizer water volume and Main Steam System pressure.

The VIPRE-D models are used to calculate the detailed subchannel thermal conditions, including a time and position dependent Departure from Nucleate Boiling Ratio (DNBR) for the 15 x 15 Upgrade fuel design.

A DNBR penalty of 3.0% will be applied to account for the increased bypass flow due to the conversion to upflow configuration. This DNBR penalty is conservative and applicable to all DNB events and will be deducted from the retained margin for the Westinghouse 15x15 Upgrade fuel product during the core reload thermal-hydraulic evaluation in accordance with NRC approved methodology in VEP-NE-2-A (Reference 17).

14.2.10.3 **Initial Operating Conditions**

The following assumptions are made in the DNBR cases:

1. The behavior of the unit is evaluated for a complete loss of steam load from power at (2589.3 MWt for the 15 x 15 Upgrade fuel design) - without a direct reactor trip to demonstrate core protection margins. A statistical treatment of key DNBR analysis parameter uncertainties is employed. Therefore, nominal initial RCS conditions are assumed, and allowances for calibration and instrument errors are incorporated into the limiting DNBR value as described in Statistical DNBR topical report (Reference 17).
2. A positive moderator temperature coefficient conservative for BOC conditions and a least negative Doppler temperature coefficient are assumed.
3. Credit is taken for the effect of pressurizer spray and power operated relief valves in reducing or limiting the coolant pressure.
4. Main feedwater flow is isolated at the time of the turbine trip for the DNB case only.

The following assumptions are made in the Non-DNBR (RCS Pressure) case:

1. The behavior of the unit is evaluated for a complete loss of steam load from full power without a direct reactor trip to demonstrate the adequacy of the pressure-relieving devices. A deterministic treatment of uncertainties in initial RCS operating conditions [e.g. pressure, temperature, flow, and core power (102% of 2546 MWt or 2597 MWt (i.e., 100.38% of 2587 MWt))] is used in the analysis.
2. A zero moderator temperature coefficient and a most negative Doppler temperature coefficient are assumed.
3. The reactor is assumed to be in manual control, which is conservative from the standpoint of maximum pressure attained.
4. Main feedwater flow is isolated at the time of the reactor trip.
5. The pressurizer safety valve tolerance is modeled with +3% PSV tolerance and 0.1 second delay. (Only the results of the overpressure transients are sensitive to the safety valve tolerance. The DNBR results are not sensitive to these parameters.)
6. No credit is taken for the effect of pressurizer spray and power operated relief valves in reducing or limiting the coolant pressure.

The following assumptions are made in both the DNBR case and non-DNBR case:

1. No credit is taken for the operation of the steam dump system, steam generator power operated relief valves, or direct reactor trip on turbine trip. The reactor is tripped on high pressurizer pressure. The steam generator pressure rises to the safety valve setpoint, where steam release through safety valves limits secondary steam pressure to less than design limit.
2. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur. The auxiliary feedwater flow would remove core decay heat following plant stabilization.
3. All cases examined assumed reactor is in manual rod control mode. This provides the limiting initial reactor power response to the event. In addition, all cases incorporate the assumption of 15% steam generator tube plugging.

14.2.10.4 **Results**

Only the BOC cases are presented here, since they provide the limiting results with respect to the analysis acceptance criteria of interest.

14.2.10.4.1 DNBR Case

Transient results for the RETRAN DNBR case are presented in Figures 14.2-54 to 14.2-58. These are discussed as follows:

Figure 14.2-54 - Nuclear power initially increases in the presence of the RCS heatup and the assumed positive moderator coefficient. Peak power reaches about 114% of 2546 MWt (112% of 2587 MWt) before the effects of reactor trip on high pressurizer pressure dominate.

Figure 14.2-55 - RCS inlet temperature increases by about 39°F prior to the excursion being terminated by reactor trip.

Figure 14.2-56 - Pressurizer liquid volume responds to the RCS heatup by increasing from 804 cubic feet to a maximum of about 1153 cubic feet leaving about 147 cubic feet of minimum steam space.

Figure 14.2-57 - Cold leg pressure follows a similar trend, reaching a peak value of 2674 psia at 15 seconds.

Figure 14.2-58 - Main steam pressure reaches a maximum value of 1174 psia (36 psia margin to the design limit) at 20 seconds. This case is expected to be limiting for main steam pressure.

The Hot Channel DNBR is shown to have considerable margin to the SAL (Section 3.2.3).

14.2.10.4.2 Non-DNBR (RCS Pressure) Case

This is the limiting RCS overpressure case. The results are presented in Figures 14.2-59 to 14.2-63. These are discussed as follows:

Figure 14.2-59 - Nuclear power does not exceed the initial value of 102% of 2546 MWt (100.38% of 2587 MWt) before decreasing in response to the reactor trip on high pressurizer pressure.

Figure 14.2-60 - RCS inlet temperature increases by about 30°F. Again the temperature increase is less than for the pressure control case because of the earlier trip.

Figure 14.2-61 - Pressurizer liquid volume responds to the RCS heatup by increasing from 854 cubic feet to a maximum of about 991 cubic feet leaving about 309 cubic feet of minimum steam space.

Figure 14.2-62 - Cold leg pressure follows a similar trend, reaching a peak value of 2669 psia (about 81 psi margin to the analysis limit) at 9 seconds.

Figure 14.2-63 - Main steam pressure reaches a maximum value of 1161 psia (49 psi margin to the design limit) at 17 seconds or slightly less than the primary pressure control case, as expected.

14.2.10.5 **Conclusions**

The analysis indicates that for a complete loss of external electrical load without a direct or immediate reactor trip the following criteria are met:

1. The minimum transient DNBR remains above the applicable SAL (Section 3.2.3).
2. Pressure at the most limiting RCS location is less than 110% of RCS design pressure, or 2750 psia (the Emergency Condition Stress Limit Specified in Section III of the ASME Code).
3. Pressure at the most limiting Main Steam System (MSS) location is less than 110% of MSS design pressure, or 1210 psia (the Emergency Condition Stress Limit specified in Section III of the ASME Code).

14.2.11 Loss of Normal Feedwater

A loss of normal feedwater (from a pipe break, pump failures, valve malfunctions, or loss of offsite ac power) results in a loss in the capability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this incident, reactor core damage could possibly occur from a sudden loss of heat sink. If an alternative supply of feedwater were not available for the unit, residual and sensible heat following reactor trip would heat the reactor coolant system water to the point at which water relief from the pressurizer relief valves occurs. A loss of significant water from the reactor coolant system could conceivably lead to core damage. A special case of this event is a main feedwater line break in the main steam valve house (outside containment). The transient is described in Section 14B.6.

The following provides the necessary protection against a loss of normal feedwater:

1. Reactor trip on low-low water level in any steam generator, unless the RCS loop stop valves are closed, or on water level below the AMSAC (ATWS Mitigation System Actuation Circuitry) setpoint in two steam generators after a time delay, providing the C-20 permissive is satisfied.
2. Reactor trip on a main steam flow-feedwater flow mismatch coincidental with a low water level in any steam generator.
3. The operation of two motor driven auxiliary feedwater pumps (350 gpm design flow for each), which can be started either automatically or manually. They are started automatically on:
   a. A low-low water level in one of three steam generators as sensed by two of three channels on that steam generator, unless the RCS loop stop valves for that steam generator are closed.
   b. The opening of one of two feedwater pump breakers on two of two main feedwater pumps.

c. Any safety injection signal.

d. The loss of all ac power, as indicated by an undervoltage on the two transfer buses corresponding to that unit's emergency buses.

e. AMSAC initiation.

4. The operation of one turbine-driven pump (700 gpm), which can be started automatically or manually. It is started automatically on:

   a. A low-low level in two of three steam generators as sensed by two of three channels for each steam generator unless the loop stop valves for those steam generators are closed.

   b. Undervoltage on two of three 4160V ac station service buses for greater than 5 seconds.

   c. AMSAC Initiation.

The motor-driven auxiliary feedwater pumps are supplied by the diesel generators if a loss of outside power occurs, and the turbine-driven pump uses steam from the steam generators. The turbine exhausts the steam to the atmosphere. The auxiliary feedwater pumps take suction directly from the 110,000-gallon emergency condensate storage tank for delivery to the steam generators.

The above provides functional diversity in equipment and control logic to ensure that reactor trip and automatic auxiliary feedwater flow will occur following any loss of normal feedwater, including that caused by a loss of ac power.

14.2.11.1 **Method of Analysis**

A detailed analysis using the RETRAN Code (Reference 12) was performed to obtain the plant transient following a loss of normal feedwater (LONF). The LONF analysis includes sensitivities on the operation of pressurizer heaters, sprays, and power operated relief valves for the effect on the pressurizer fill and RCS overpressure criteria.

The following assumptions were made:

1. Reactor trip occurs when the steam generator water level reaches the narrow range low-level tap in the steam generator.
2. The plant is operating at 102% of 2546 MWt (100.38% of 2587 MWt).
3. The core residual heat generation is based upon long-term operation at the initial power level preceding the trip.
4. The loss of alternating current power case assumes offsite power becomes unavailable at the time reactor trip occurs. The reactor coolant pumps are tripped off coincident with reactor trip.

5. For offsite power available - two motor-driven auxiliary feedwater pumps are available 1 minute after the accident. The pumps are capable of providing 250 gpm of auxiliary feedwater per pump. The turbine driven auxiliary feedwater pump is assumed inoperable.

   For loss of offsite power - one motor-driven auxiliary pump is available 1 minute after the accident. The pump is capable of providing 300 gpm of auxiliary feedwater. The turbine driven auxiliary feedwater pump is assumed inoperable and the second motor-driven auxiliary feedwater pump is not readily available, within the 1 minute timeframe.

6. Auxiliary feedwater is distributed to the steam generators through a common header.

7. Secondary system steam relief is achieved through the self-actuated safety valves. Note that steam relief is typically through the power-operated relief valves or condenser dump valves for most cases of loss of normal feedwater. However, for conservatism, these components are assumed unavailable.

8. The initial reactor coolant average temperature is 4°F higher than the nominal value, since this results in a greater expansion of reactor coolant system water during the transient and a higher water level in the pressurizer.

9. An uncertainty of 8.5% in the full-power programmed pressurizer level is assumed. It should be noted with regard to this incident that even if the pressurizer does fill, the low surge rate would not cause an excessive pressure rise.

10. Initial pressurizer pressure is 30 psi above its nominal value.

11. The analysis is performed with and without alternating current power to the station auxiliaries.

14.2.11.1.1 Case 1 - Offsite Power Unavailable

Figures 14.2-64 through 14.2-67 show the unit parameters following a loss of normal feedwater incident according to the assumptions listed above. Following the reactor and turbine trip, the water level in the steam generators will fall because of a reduction of the steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. For the limiting case, one minute following the initiation of the low-low level trip, one auxiliary feedwater pump is automatically started, reducing the rate of water level decrease. The capacity of the auxiliary feedwater pump is such that the water level in the steam generators being fed does not recede below the lowest level at which sufficient heat transfer area is available to dissipate core residual heat without water relief from the primary system relief or safety valves.

The loss of alternating current power (LOAC) is a special case of the LONF event from an analysis standpoint. The LONF event followed by a reactor coolant pump trip on low-low steam generator water level conservatively bounds the LOAC event. Figures 14.2-64 through 14.2-67 present pressurizer pressure, pressurizer water volume, RCS loop temperature, and core inlet flow rate, respectively, for a case assuming the pressurizer heaters are operational. The analysis of the loss of normal feedwater event demonstrates that the auxiliary feedwater system will remove the stored and residual heat, thus preventing overpressurization and liquid relief of RCS inventory through the pressurizer safety valves or pressurizer power operated relief valves.

14.2.11.1.2 Case 2 - Offsite Power Remains Available

The offsite power available case assumes continuous operation of the reactor coolant pumps. All other assumptions are consistent with those cited earlier. Figures 14.2-68 through 14.2-71 present pressurizer pressure, pressurizer water volume, RCS loop temperature, and core inlet flow rate, respectively, for a case assuming the pressurizer heaters are operational. This case demonstrates the adequacy of the long-term heat removal capability of the AFW System.

14.2.11.2 **Conclusions**

The loss of normal feedwater does not result in any adverse condition in the core, because it does not result in water relief from the pressurizer relief or safety valves, nor does it result in an uncovering of the tube sheets of the steam generators being supplied with water. A long term decrease in the pressurizer water volume is shown, peak RCS pressure does not exceed 2750 psia, main steam pressure is less than 1210 psia, and the total secondary liquid inventory of the three steam generators does not decrease below 15,000 lbm.

14.2.12 Loss of All Alternating Current Power to the Station Auxiliaries

In the event of a complete loss of offsite power and a turbine trip, there would be a loss of power to the unit auxiliaries (i.e., the reactor coolant pumps, main feedwater pumps, etc.). The events following a loss of ac power with turbine trip are as follows:

1. Unit vital instrument loads are supplied by the emergency power sources.
2. As the steam system pressure increases, the steam system power-operated relief valves are automatically opened to the atmosphere. (Steam bypass to the condenser is assumed to be unavailable, since the steam bypass is not required for reactor protection.)
3. If the steam flow rate through the power-operated relief valves is not sufficient (or if the power relief valves are not available), the steam generator self-actuated safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.
4. As the no-load temperature is approached, the steam power-operated relief valves (or self-actuated safety valves if the power-operated relief valves are not available for any reason) are used to dissipate the residual heat and to maintain the unit in the hot-shutdown condition.
5. The emergency diesel generators will start on a loss of voltage on the emergency 4160V buses to supply unit vital loads.

The auxiliary feedwater system is started automatically as discussed in Section 14.2.11. The steam-driven auxiliary feedwater pump uses main steam and exhausts to the atmosphere. The motor-driven auxiliary feedwater pumps are supplied by power from the diesel generators. The pumps take suction directly from the 110,000-gallon emergency condensate storage tank for delivery to the steam generators. The auxiliary feedwater system ensures a feedwater supply of at least the 300 gpm value assumed in the analysis upon loss of power to the station auxiliaries.

The auxiliary steam turbine-driven feedwater pump has a nominal capacity of 700 gpm and the motor driven auxiliary feedwater pumps have a nominal capacity of 350 gpm each.

The steam-driven pump can be tested at any time by admitting steam to the turbine driver. The motor-driven pumps also can be tested at any time. The valves in the system can be operationally tested at any time.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and for the removal of residual heat is maintained by natural circulation in the reactor coolant loops. The natural circulation flow was calculated for the conditions of equilibrium flow and maximum loop flow impedance. The results given by the model are within 15% of the measured flow values obtained during natural circulation tests conducted at the Yankee-Rowe plant and confirmed at San Onofre and Connecticut Yankee. The natural circulation flow ratio as a function of reactor power is given in Table 14.2-1.

It is shown in Section 14.2.11 that a loss of normal feedwater from any cause, including a loss of offsite ac power, does not result in water relief from the pressurizer relief or safety valves.

The loss of ac power to the station auxiliaries does not cause any adverse condition in the core since it does not result in water relief from the pressurizer relief or safety valves.

14.2.13 Likelihood of Turbine-Generator Unit Overspeed

A turbine missile can be generated by a rotor fracture releasing fragments capable of causing significant damage. A large rotor fragment is interpreted to be a sector of a rotor disk forging, of between 90° and 180° included angle, separated by fracture along several radial-axial planes and rupture of the welds.

The material used for the six disk forgings of each LP rotor is a 2%Cr-Ni-Mo steel. The absence of defects of any significant size from the disk forgings, as purchased, is ensured by stringent ultrasonic inspection. The rotors are of welded construction designed to ensure long-term integrity. Each rotor consists of six separate forgings, joined at their outside diameters by submerged-arc welding. In each of the opposed flows, a center disk carries the first six stages of moving blades, the intermediate disk carries the penultimate stage blades and the last disk carries the last stage blades. The improved welded rotor design characteristics include low yield strength material, no shrunk-on disks, homogeneous properties due to small volume of each disk, and verification of absence of material defects by high resolution ultrasonic inspection performed on small size of each forging. These design features contribute to the elimination of the risk of rotor fracture.

There are two quite different circumstances in which the risk of rotor fracture may arise, which are categorized as high-speed burst and low-speed burst events.

The high-speed burst could occur if there is an accidental loss of electrical load concurrent with the failure of turbine protection system components. If the HP turbine governor valves were not automatically closed then the rotor would accelerate to a speed approaching twice the normal running speed. At this speed there is a high probability that LP rotors would fracture, releasing fragments. The low probability of such an event is determined by the low probability of this overspeed ever occurring. The probability of a high-speed burst is unaffected by the turbine retrofit due to the high reliability of the control system components.

A low-speed burst could occur due to a mechanism of deterioration leading to the progressive weakeninq of the rotor which may fail at normal speed, or at a low overspeed. This includes 10 percent above normal speed during periodic overspeed trip tests at no load and 20 percent above normal speed following loss of electrical load and an overspeed trip. The low probability of such an event is determined by design of the rotors to ensure long-term integrity and by periodic inspection to detect any sign of deterioration.

The Alstom Power methodology for the turbine missile generation probability calculation is included in Alstom Standard STD0010572, Reference 40.

The methodology used in this report is the same methodology used by ABB (now Alstom) in the missile analysis report for the Maine Yankee Unit and several others for US utilities. This missile generation probability methodology was the basis for the change in the turbine rotor inspection frequency requested in Maine Yankee Technical Report Amendment 134 to the NRC. The NRC approved Maine Yankee Amendment 134 and stated in their approval that the ABB's probability analysis (turbine missile generation probability calculation) is consistent with NRC approved methodology.

Alstom Standard STD0011103, Reference 44, confirmed that the missile generation probability methodology in Alstom Standard ST0010572 that is used for Surry Power Station is the same missile generation probability methodology as that approved for Maine Yankee.

Therefore, use of the Alstom Power methodology for turbine missile generation probability calculations included in Alstom Standard ST00010572 is consistent with the NRC requirements included in NUREG 0800 for turbine missile generation probability calculations.

This methodology used by Alstom is for estimating the probability of low-speed rotor fracture and/or missile generation due to stress corrosion cracking. The following two failure modes were evaluated:

1. Growth of an Initial Defect by Fatigue

The ultimate inspection standards ensure that any initial defect of significant size is detected and rejected. A conservative assumption is made that, despite this, a large embedded defect of 0.4 inch diameter remains in the disk in a location subject to the highest tangential stress. The evaluation indicates that the margin between a large extended defect size and the minimum critical crack size is a factor of more than 10, and there is no credible failure by this mechanism.

2. Initiation and Growth of Cracks due to Stress Corrosion Cracking (SCC)

   Design procedures developed using the Alstom Power Threshold Stress Approach (TSA), as described in Reference 41, indicate that any risk of stress corrosion cracking Surry retrofit LP rotors is eliminated by design and materials selection. LP rotors of welded construction type indicate no SCC in the relevant radial-axial plane which could extend to release large rotor fragments. Despite the fact that a rotor fracture has never occurred on an Alstom welded rotor, the residual risk of missile generation has been evaluated by probabilistic methods.

   The probability of rotor fracture has been determined by assigning probability distributions to the values of SCC growth rate, stress, and crack geometry. A Monte Carlo analysis was performed to determine the probability of failure. The calculation method and results of estimating the probability of missile generation resulting from the initiation and growth to a critical size of a SCC is described in the following sections:

   a. Crack Initiation

      The initiation probability is taken as a constant value calculated on the basis of the statistics of SCC cracks found in Alstom Power welded rotors during inspections after periods of service. The statistics are based on long-term service but no credit is assumed for design procedures introduced to eliminate susceptibility to SCC initiation as described in Reference 41.

      Using the methodology of Reference 43, the best estimate of the probability of SCC initiation, for 50 percent confidence, is 0.00125. There have been a small number of SCC cracks which have initiated at the internal corners of the blade root slots. In the limited number of cases where this cracking has been observed, the rotors were produced before the application of the Alstom Power TSA, and the calculated stresses at the locations of the cracking have been found to exceed those permitted by TSA. No SCC cracking has been observed at a location where the calculated stress satisfies the requirements of the Alstom Power TSA, to which the Surry retrofit LP rotors have been designed.

   b. Crack Growth Rate

      Stress corrosion cracks appear after an initial period of exposure to stress in the presence of wet steam. It is conservatively assumed that any crack that initiates does so immediately on entering service and begins to grow immediately.

Based on the available data for stress corrosion cracks found in the power-industry service and determined from laboratory tests, the rate of crack growth under steady load can be described (Reference 43) as a log-normally distributed function of temperature and material yield stress.

The probability distribution of stress corrosion crack growth is illustrated in Figure 14.2-72. The rate of crack growth is independent of the crack stress intensity, and therefore independent of applied stress. The decrease in rate at low stress intensities is neglected in this analysis. The increase in rate at high stress intensities is dealt by assuming, very conservatively, that if the crack stress intensity reaches 100 ksi. $\sqrt{\text{in}}$ (ksi square root inches is a unit in the category of fracture toughness, ksi. $\sqrt{\text{in}}$ has a dimension of $\sigma\sqrt{L}$ where σ is applied stress in ksi and L is the crack length in inches) then the acceleration is so great that the fracture follows almost immediately. This is equivalent to reducing the assumed fracture toughness to 100 ksi. $\sqrt{\text{in}}$ in calculating critical crack size at normal speed, as discussed below.

c. Critical Crack Size

The critical crack size at which rotor fracture will occur is dependant on crack geometry factor, rotor disk fracture toughness, and applied stress.

The minimum rotor disk fracture toughness guaranteed by the property specification of the most vulnerable rotor disks, the center disks, is 154 ksi. $\sqrt{\text{in}}$, and the actual values achieved are likely to be significantly higher. However, the calculation is performed by substituting lower value of 100 ksi. $\sqrt{\text{in}}$.

The crack geometry factor has limiting values of 1.99 for a parallel sided crack and 1.26 for a semi-circular crack. These values are appropriate to planar cracks and, conservatively, neglect any increase in critical crack size that might result from crack branching. Between these limits the geometry factor is assumed to be uniformly distributed, so that any value in this range is equally probable. The probability distribution is shown in Figure 14.2-73.

The applied stress is taken to be the mean tangential stress acting over the critical crack depth, determined from the tangential stress contours of Figure 14.2-74. For a given value of crack geometry factor, the mutually compatible values of crack depth and mean tangential stress over that crack depth which satisfy the condition that the crack tip stress intensity equals the limit of 100 ksi. $\sqrt{\text{in}}$ for stable crack propagation are calculated. The variation of this critical crack depth with the crack geometry factor is shown in Figure 14.2-75.

The distribution of tangential stress shown in Figure 14.2-74, which was determined by finite element analysis, is conservatively assumed to be subject to a calculational error of ±10% in line with Reference 43, and is assumed to be distributed linearly around the calculated value. The probability distribution and the corresponding cumulative probability distribution are shown in Figure 14.2-76.

d. Failure Probability

The probability of failure, i.e., that a stress corrosion crack grows to a size that could cause fast fracture of the rotor after any specified period of service, assuming immediate initiation, was determined using a Monte Carlo analysis. For each period of service, ranging from 60,000 hours to 150,000 hours, a large number of trial calculations were carried out in which each of the three variable parameters (SCC growth rate, crack geometry factor, and rotor tangential stress) were randomly selected from its associated probability distribution using randomly generated numbers between zero and one.

The probability of a rotor disk fracture due to SCC initiation and growth is determined as a function of time (Reference 42). Alstom recommends major rotor inspection intervals of 100,000 operating hours. The calculated probability of rotor fracture per unit year during the final year of operation prior to reaching 100,000 hours is 6.96×10^{-8}.

Alstom missile analysis (Reference 40) has concluded that the probability of lowspeed fracture for Surry Power Station LP turbine retrofit rotors is 6.96×10^{-8} per unit year which is less than one hundredth of the acceptable limit of 1×10^{-5} permitted for unfavorably orientated plants by the NRC guidelines. The LP turbine rotor will be inspected per Dominion's inspection program based on the manufacturer's recommendations (Reference 42). This inspection verifies that the rotor will continue to meet the required design safety limit.

Dominion inspection requirements for LP rotors during major overhaul ensure that any indications of SCC which could develop to cause rotor fracture will be detected. The inspection includes a thorough visual inspection for erosion and corrosion damage and magnetic particle examination of selected areas to detect any cracking at the rotor surfaces. In the very unlikely event of surface indications being detected, additional ultrasonic examinations would be performed.

Alstom Power evaluated the probability of missile generation for Surry turbine using the methodology which was previously used for Maine Yankee unit. The methodology was approved by the NRC in Maine Yankee Amendment 134 Safety Evaluation Report. This methodology complies with the SRP Acceptance criteria of NUREG 0800 Section 3.5.1.3, Turbine Missiles.

The probability of missile generation from either unit is so low that it can be discounted and there is no missile strike envelope.

Because of the redundant means of overspeed protection and reliability of the turbine control protection system and of the main steam system, the possibility of unit speeds above the design value (120%) is very remote.

A description of the electro-hydraulic governing system and its operation is given in Section 10.3.3.

In addition to design provisions associated with the turbine control and protection system, the governor and main stop valves are exercised on a periodic basis during unit operation to further reduce the possibility of valve stem sticking. Analyses of oil samples are performed regularly.

The turbine is periodically oversped to check the tripping speed. The remaining tripping devices are routinely checked.

14.2 REFERENCES

1. Westinghouse Electric Corporation, *Power Distribution Control in Westinghouse Pressurized Water Reactor*, WCAP-7208, 1968.
2. Letter from C. M. Stallings, Vepco, to K. R. Goller, NRC, Subject: Unit 2 Cycle 2 Reload Evaluation, dated March 12, 1975 (Serial No. 458).
3. Westinghouse Electric Corporation, *Calculation of Flow Coastdown After Loss of Reactor Coolant Pump (PHOENIX Code)*, WCAP-7551, August 1970.
4. Westinghouse Electric Corporation, *LOFTRAN Code Description*, WCAP-7907-A, April 1984.
5. Westinghouse Electric Corporation, *Fuel Densification - Surry Power Station*, WCAP-8013, December 1972.
6. Westinghouse Electric Corporation, *FACTRAN - A Fortran IV Code for Thermal Transients in a* UO^2 *Fuel Rod*, WCAP-7337, 1972.
7. Westinghouse Electric Corporation, *Fuel Densification, Surry Units 1 and 2, Low Pressure Analysis*, WCAP-8117, 1973.
8. Westinghouse Electric Corporation, *Fuel Densification Experimental Results and Model for Reactor Application*, WCAP-8219, 1973.
9. Letter from C. M. Stallings, Vepco, to K. R. Goeller, NRC, dated March 12, 1975 (Serial No. 458).
10. Letter from C. M. Stallings, Vepco, to K. R. Goeller, NRC, dated June 5, 1975 (Serial No. 553).

11. Letter from C. M. Stallings, Vepco, to K. R. Goeller, NRC, dated September 9, 1977 (Serial No. 403).

12. *Vepco Reactor System Transient Analyses Using the RETRAN Computer Code*, VEP-FRD-41, Rev. 0.2-A, March 2015.

13. F. W. Sliz and K. L. Basehore, *Vepco Reactor Core Thermal-Hydraulic Analysis Using the COBRA III C/MIT Computer Code*, VEP-FRD-33-A, October 1983.

14. Letter from W. L. Stewart, Vepco, to H. R. Denton, NRC, dated April 1, 1985 (Serial No. 457).

15. Letter from C. P. Patel, USNRC, to W. L. Stewart, Vepco, Surry Units 1 and 2 - Issuance of Amendments 116/116 Re: Control Rod Assemblies and Surry Improved Fuel, dated January 6, 1988.

16. Letter from B. C. Buckley (NRC) to W. L. Stewart (Virginia Electric and Power Company), Surry Units 1 and 2 - *Issuance of Amendments Re: F Delta H Limit and Statistical DNBR Methodology*, Serial 92-405, June 1, 1992.

17. R. C. Anderson, *Statistical DNBR Evaluation Methodology*, VEP-NE-2-A, June 1987.

18. Westinghouse Electric Corporation, Methodology for the Analysis of the Dropped Rod Event, WCAP-11394-P-A, January 1990.

19. Letter from L. A. Walsh (Westinghouse Owner's Group Steam Generator Tube Uncovery Task Team) to R. C. Jones, NRC, *Westinghouse Owner's Group Steam Generator Tube Uncovery Issue*, OG-92-25, March 31, 1992.

20. *LOCADOSE NE319, A Computer Code System for Multi-Region Radioactive Transport and Dose Calculation*, Theoretical Manual, Revision 10, August 2004, Bechtel Power Corporation, San Francisco, CA.

21. *LOCADOSE NE319, A Computer Code System for Multi-Region Radioactive Transport and Dose Calculation*, User's Manual, Revision 10, August 2004, Bechtel Power Corporation, San Francisco, CA.

22. *LOCADOSE NE319, A Computer Code System for Multi-Region Radioactive Transport and Dose Calculation*, Validation Manual, Revision 12, August 2004, Bechtel Power Corporation, San Francisco, CA.

23. U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, *Standard Review Plan*, NUREG-0800, Revision 2, July 1981.

24. K. G. Murphy and K. M. Campe, *Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19*, 13th AEC Air Cleaning Conference, August 1974.

25. U.S. Nuclear Regulatory Commission, Office of Standards Development, *Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants*, Regulatory Guide 1.52, Revision 2, March 1978.

26. Letter from W. L. Stewart (Virginia Power) to U.S. Nuclear Regulatory Commission, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Control Room Habitability, Operator Dose Assessment*, Serial Number 89-381, June 1989.

27. Letter from W. L. Stewart to USNRC, *Amendment to Operating Licenses NPF-4 and NPF-7; North Anna Power Station Units 1 and 2; Proposed Technical Specifications Changes*, NRC Letter Serial No. 85-077, dated May 2, 1985 (North Anna Core Uprating Project).

28. Letter from W. L. Stewart to H. R. Denton, *Virginia Electric and Power Company; Response to NRC Request to Additional Information; Core Uprate Program; North Anna Power Station Units 1 and 2*, Serial No. 85-772A, dated February 6, 1986.

29. Letter from L. B. Engle (NRC) to W. L. Stewart, *Amendments 84 and 71 to Facility Operating Licenses NPF-4 and NPF-7*, NRC Letter Serial No. 86-575, dated August 25, 1986 (North Anna Core Uprating Project).

30. R. C. Anderson, *Qualification of the WRB-1 CHF Correlation in the Virginia Power COBRA Code*, VEP-NE-3-A, July 1990.

31. S. L. Davidson (Ed.), et al, *VANTAGE+ Fuel Assembly Reference Core Report*, WCAP-12610-P-A (Proprietary), April 1995.

32. NRC - Regulatory Guide 1.183, *Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,* July 2000.

33. Letter - NRC to Virginia Power, *Surry Units 1 and 2 - Issuance of Amendments RE: Alternative Source Term (TAC no. MA8649 and MA8650),* March 8, 2002.

34. NUREG/CR-2858, PAVAN: *Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations,* USNRC, 1982.

35. Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Measurement Uncertainty Recapture Power Uprate (TAC Nos. ME2393 and ME3294)*, ML101750002, Dominion Serial Number 10-580, September 24, 2010.

36. DOM-NAF-2-A, *Reactor Core Thermal-Hydraulics Using the VIPRE-D Computer Code*.

37. Letter from J. A. Price (Dominion) to USNRC Document Control Desk, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Proposed License Amendment Request, Relocation of Core Operating Limits to the Core Operating Limits Report (COLR) and Addition of COLR References*, Serial No. 09-581, October 16, 2009.

38. Letter from K. Cotton (NRC), to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Request for Technical Specification Revisions Related to the Core Operating Limits Report (TAC Nos. ME2591 and ME2592)*, October 19, 2010, Serial No. 10-645.

39. H. H. Shah and P. Schueren, *Optimized ZIRLO™,* WCAP-12610-P-A and CENPD-404-P-A, Addendum 1-A, July 2006.

40. ALSTOM Power, Inc., *North Anna 1 & 2 and Surry 1 & 2 LP Retrofit Missile Analysis*, STD0010572, 2009.

41. ALSTOM Power, Inc., *Finite Element Investigation and Optimization of Stages 3 to 6 to Eliminate SCC Risk,* STD0001300, 2003.

42. ALSTOM Power, Inc., *Recommendations for the Inspection of LP Retrofit Internals on Nuclear Turbines*, HTGD672084, Revision A, 2004.

43. W. G. Clark, Jr., B. B. Seth &D. H. Shaffer, A*SME 81-JPGC-Pwr-31, Procedures for Estimating the Probability of Steam Turbine Disc Rupture from Stress Corrosion Cracking*, 1981.

44. ALSTOM Power, Inc., *Missile Analysis Methodology Comparison*, STD0011103, 2009.

Table 14.2-1
NATURAL CIRCULATION REACTOR COOLANT FLOW VERSUS REACTOR POWER (ORIGINAL)

Reactor Power (% full power)	Reactor Coolant Flow (% nominal flow)
3.5	5.0
3.0	4.7
2.5	4.4
2.0	4.1
1.5	3.8
1.0	3.3

Table 14.2-2
DELETED

Table 14.2-3
DELETED

Table 14.2-4
DELETED

Figure 14.2-1
ROD WITHDRAWAL FROM SUBCRITICAL - NEUTRON POWER

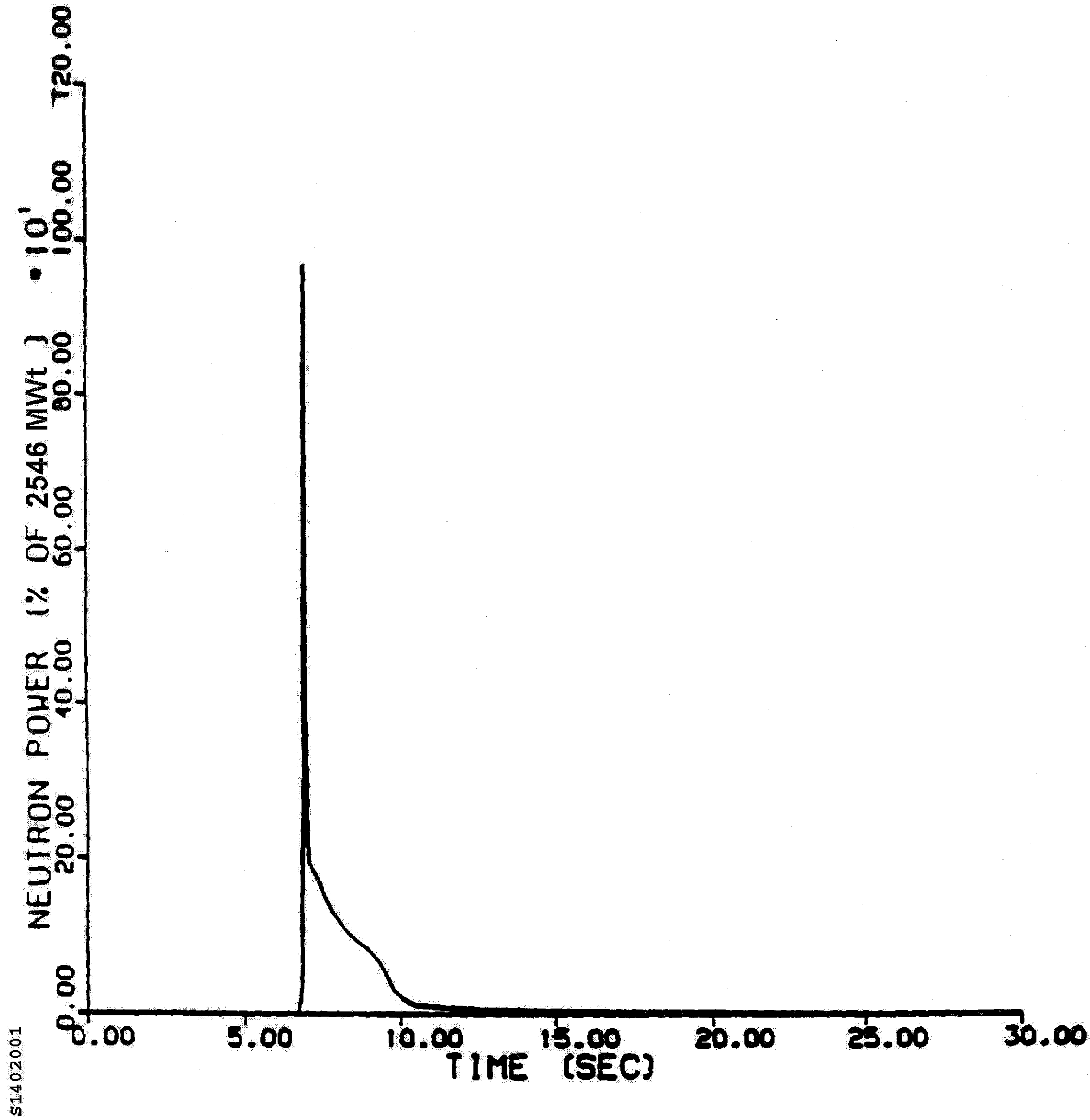
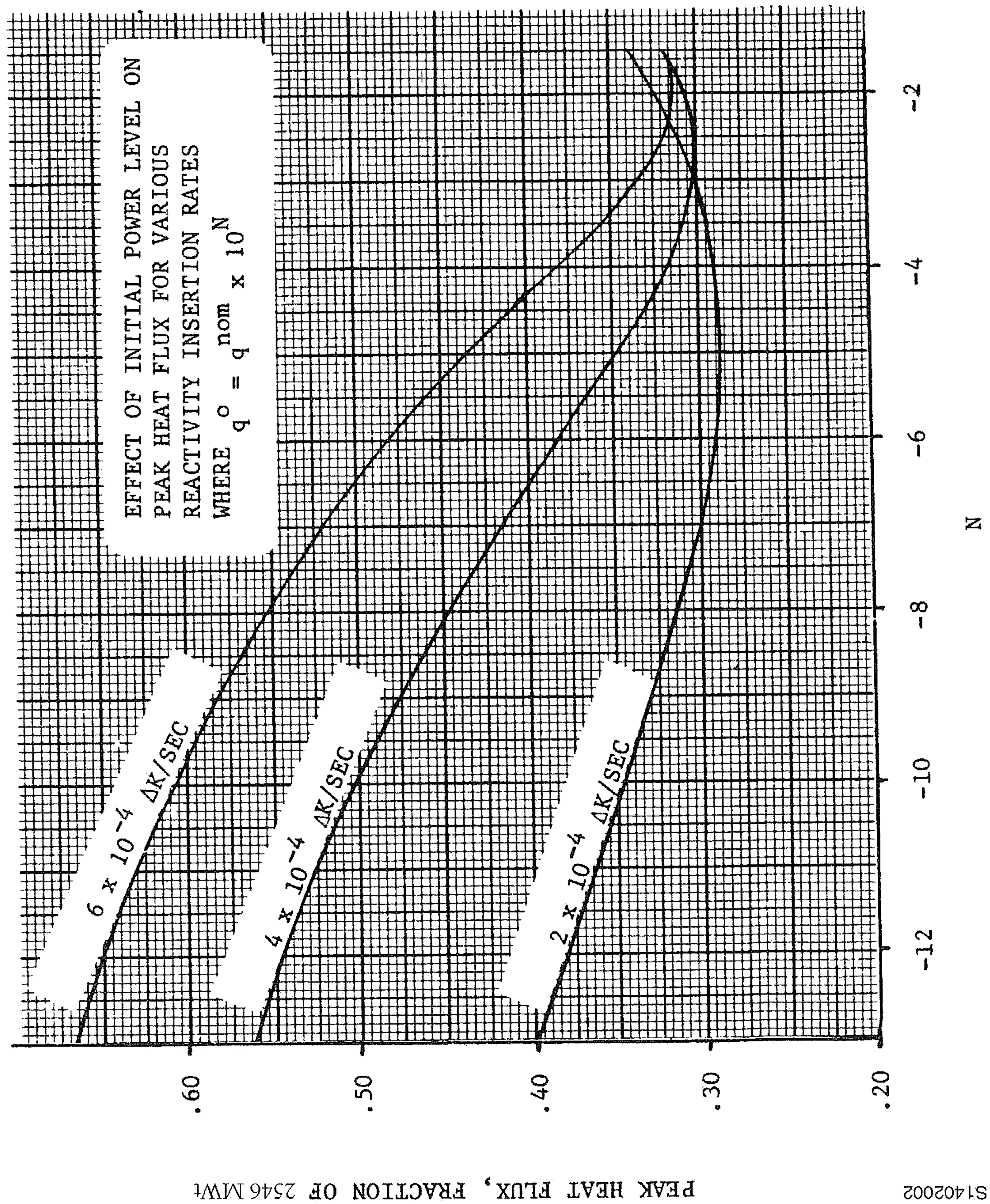


Figure 14.2-2
UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION,
PEAK HEAT FLUX



S1402002

Figure 14.2-3
ROD WITHDRAWAL FROM SUBCRITICAL - CORE HEAT FLUX

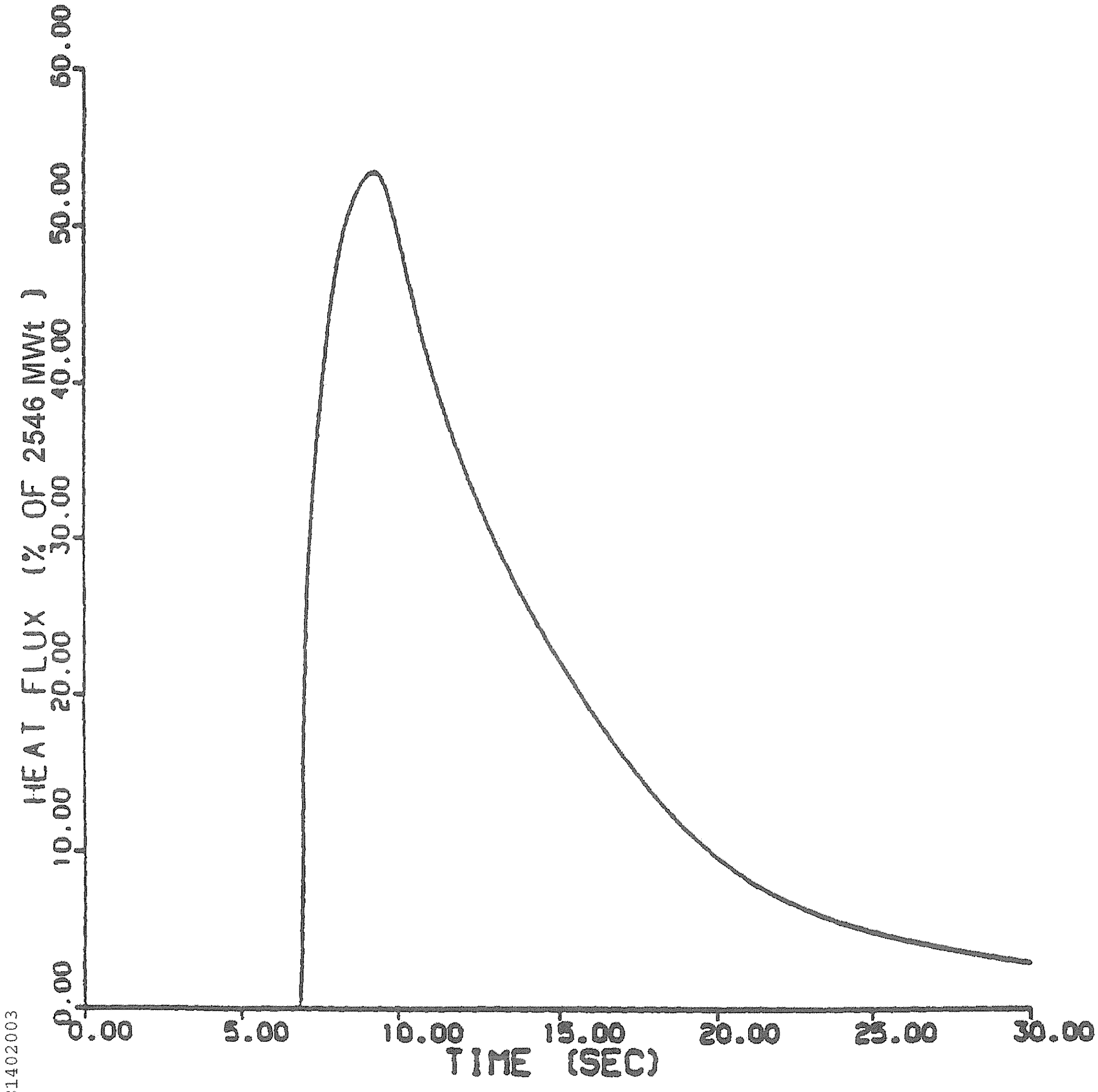
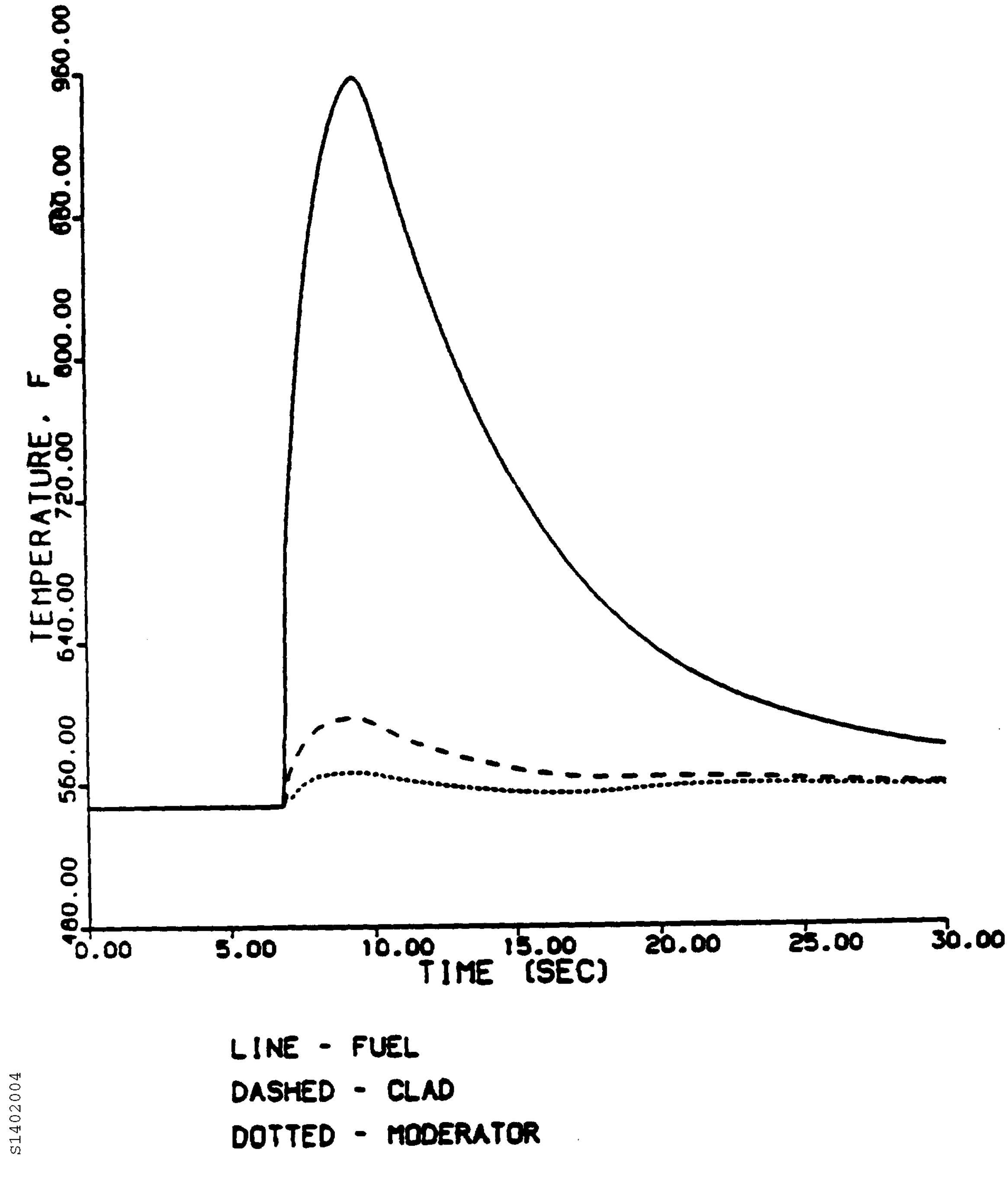


Figure 14.2-4
ROD WITHDRAWAL FROM SUBCRITICAL - TEMPERATURES
(FUEL, CLAD, MODERATOR)



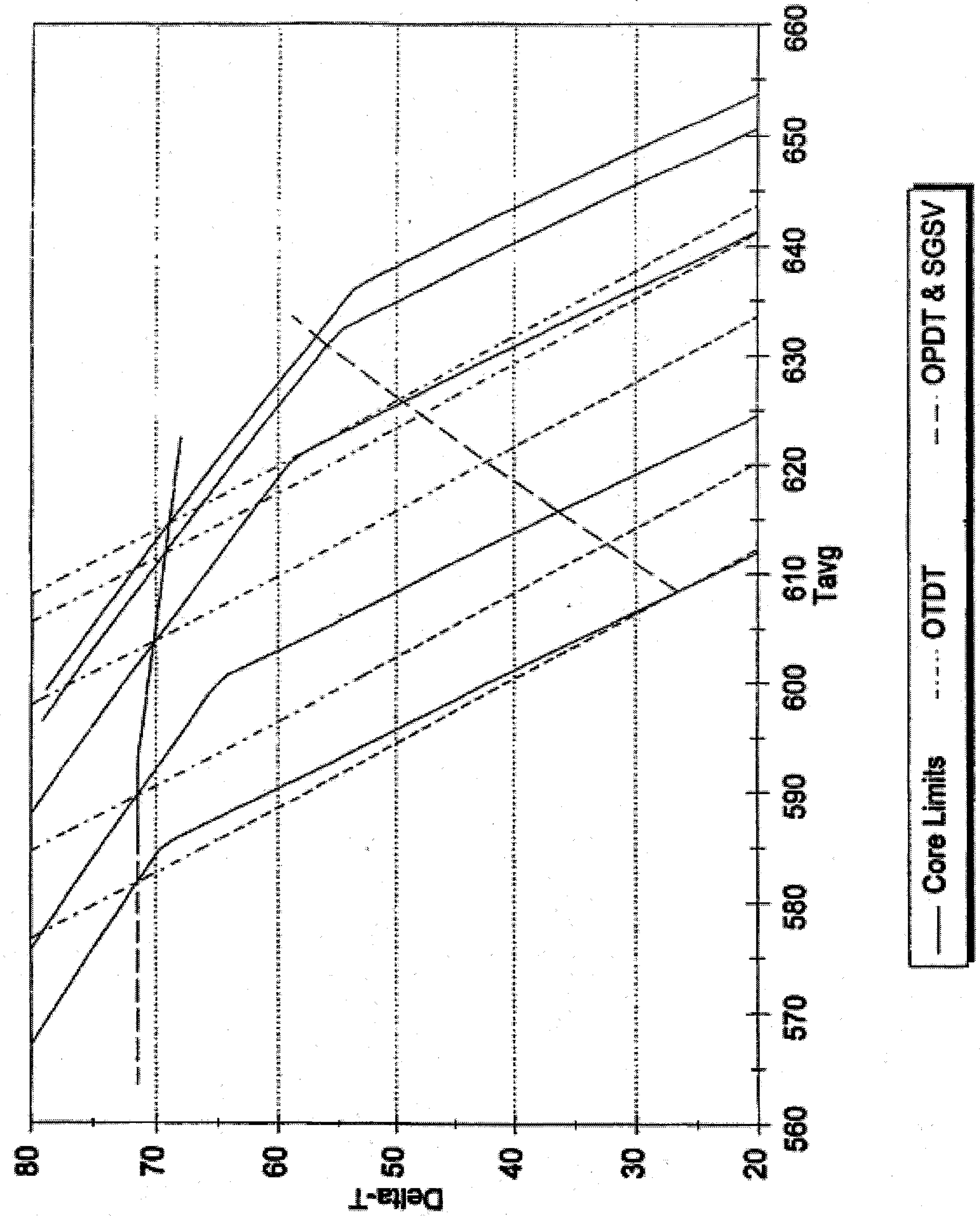


Figure 14.2-5
ILLUSTRATION OF OVERTEMPERATURE AND OVERPOWER DELTA-T PROTECTION

Figure 14.2-6
ROD WITHDRAWAL AT POWER
MINIMUM DNBR VS. INSERTION RATE AT 2589.3 MWt

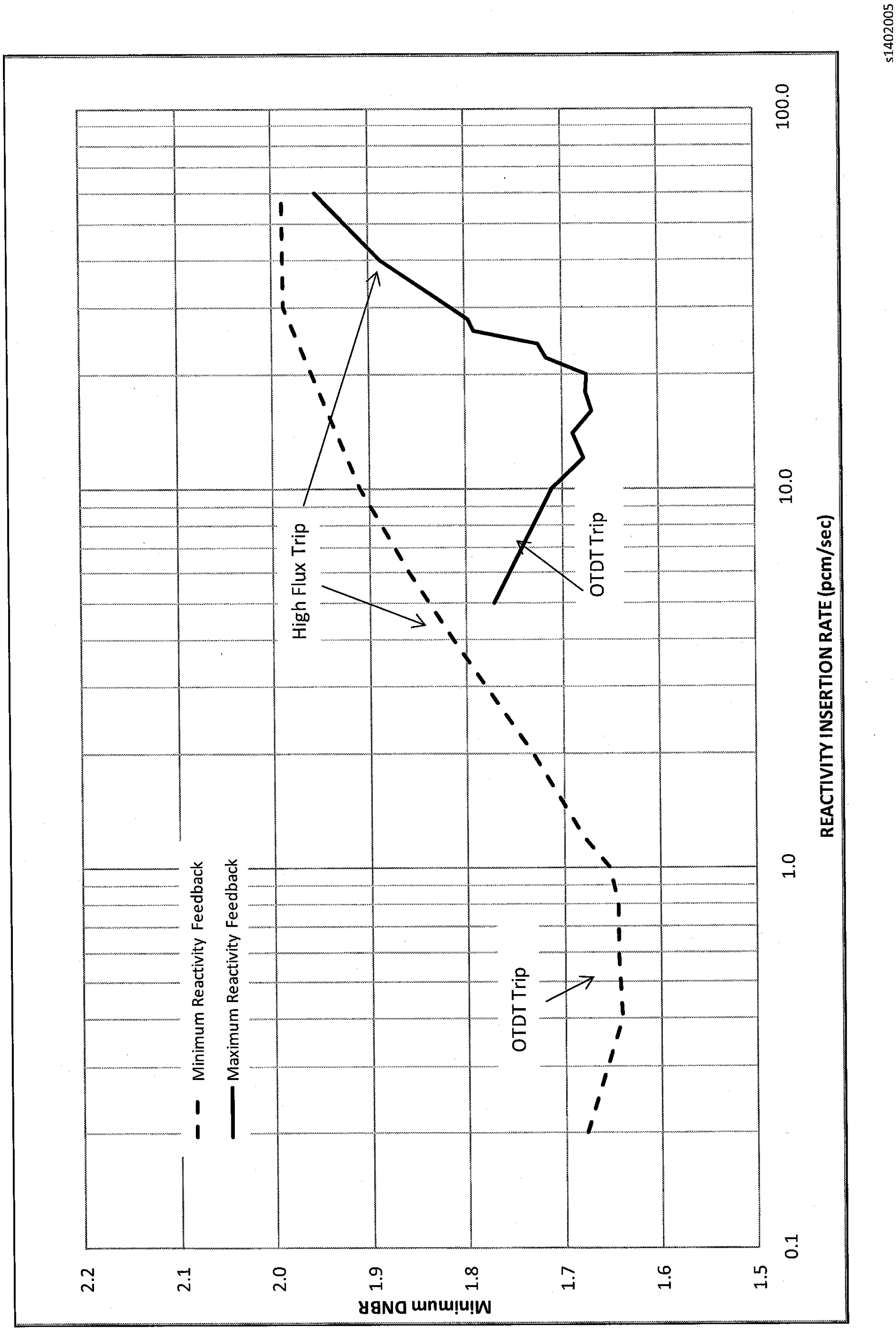


Figure 14.2-7
ROD WITHDRAWAL AT POWER
NUCLEAR POWER - LIMITING DNBR CASE AT 2589.3 MWt

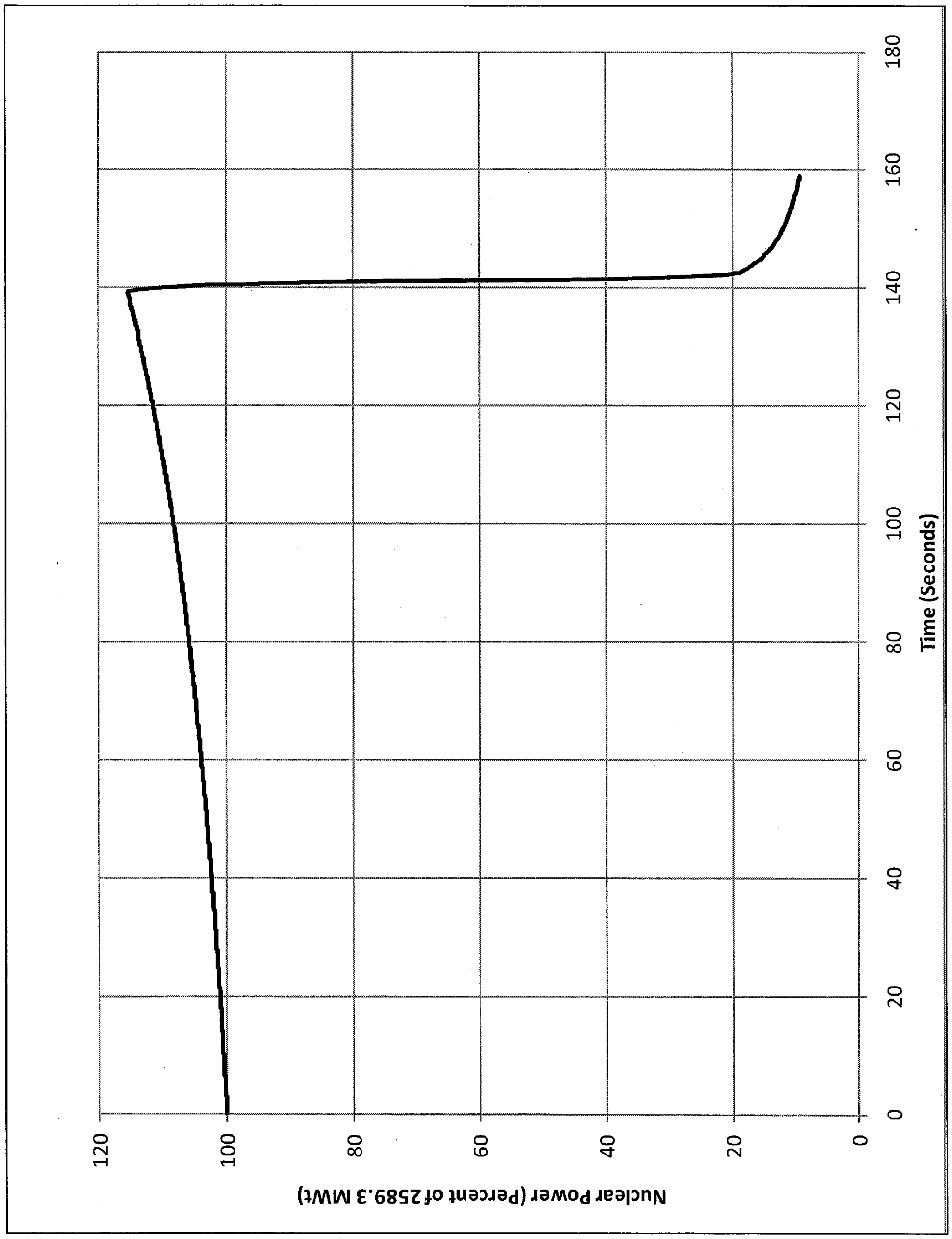


Figure 14.2-8
ROD WITHDRAWAL AT POWER
PRESSURIZER PRESSURE - LIMITING DNBR CASE AT 2589.3 MWt

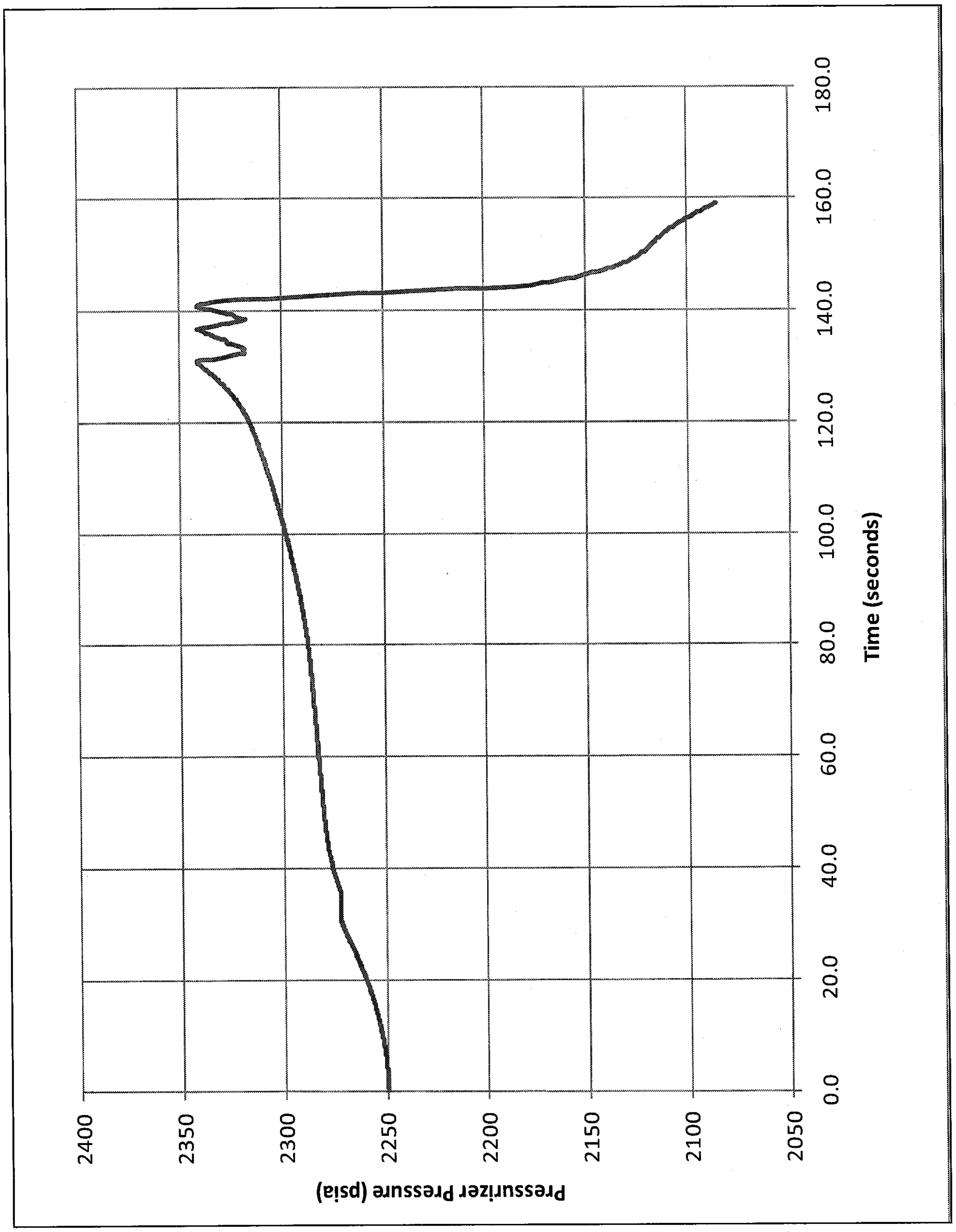
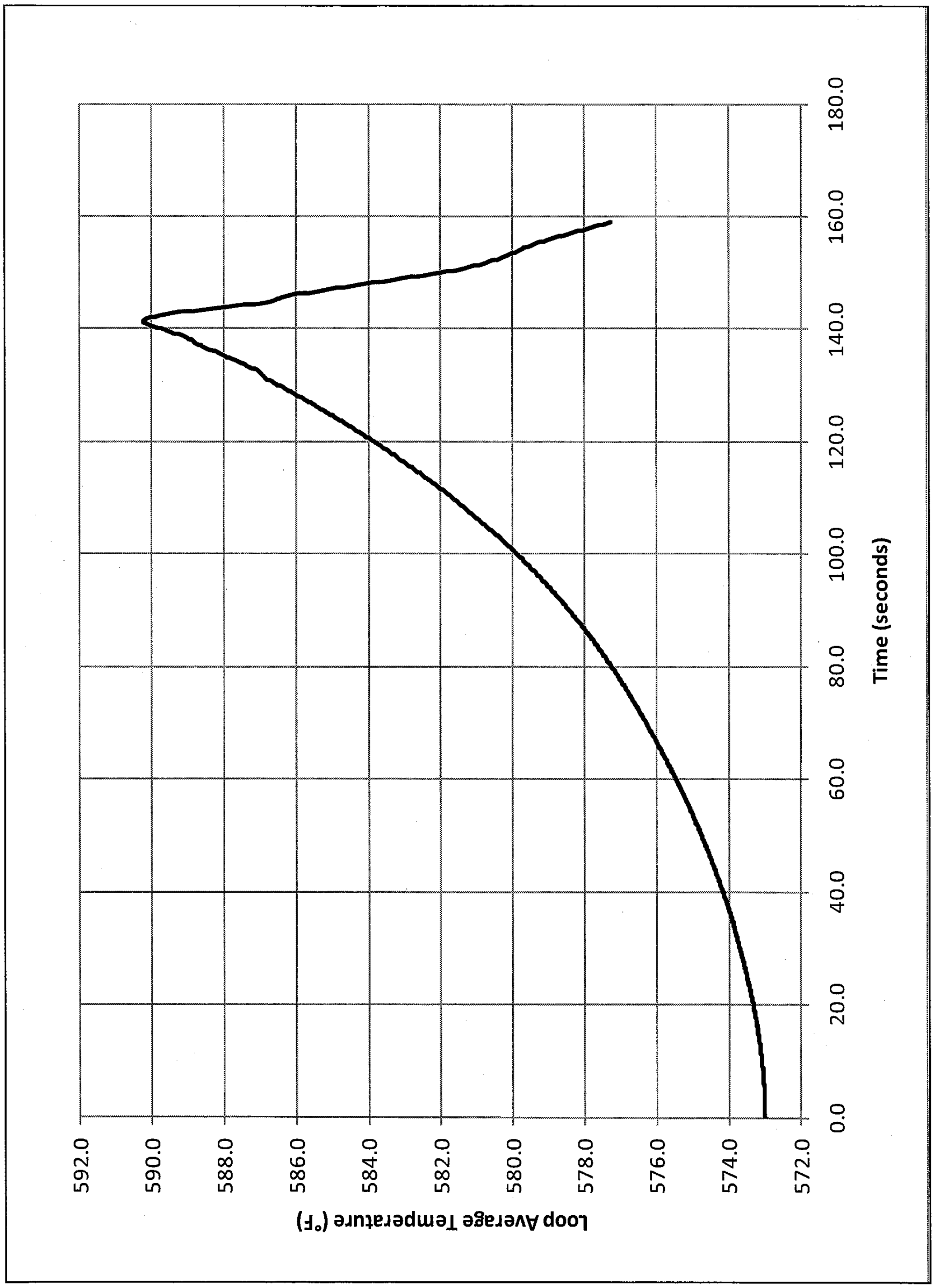
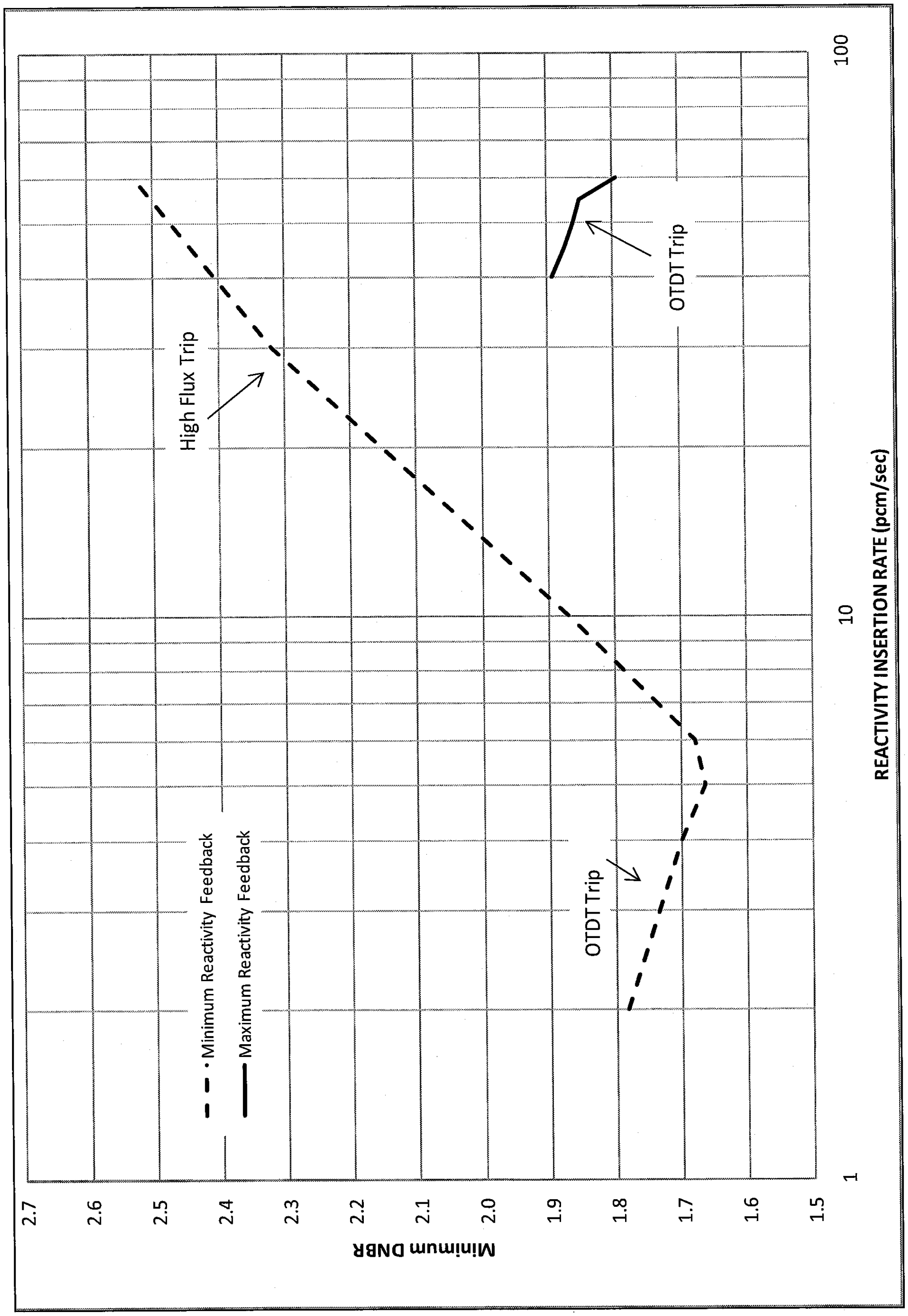


Figure 14.2-9
ROD WITHDRAWAL AT POWER
RCS AVERAGE TEMPERATURE - LIMITING DNBR CASE AT 2589.3 MWt



s1402008

Figure 14.2-10
ROD WITHDRAWAL AT POWER
MINIMUM DNBR VS. INSERTION RATE AT 60% OF 2546 MWt



s1402009

Figure 14.2-11
ROD WITHDRAWAL AT POWER
MINIMUM DNBR VS. INSERTION RATE AT 10% OF 2546 MWt

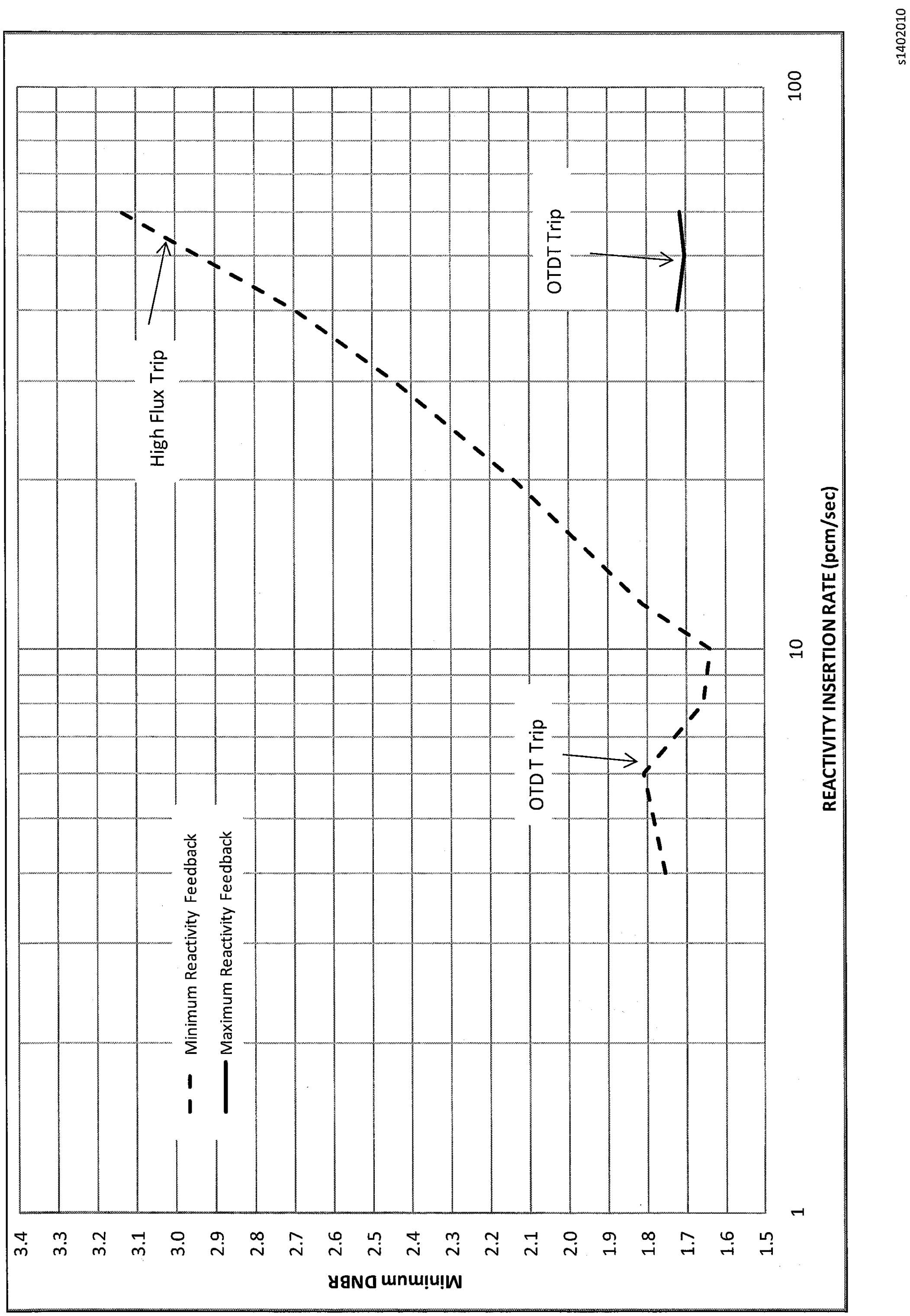
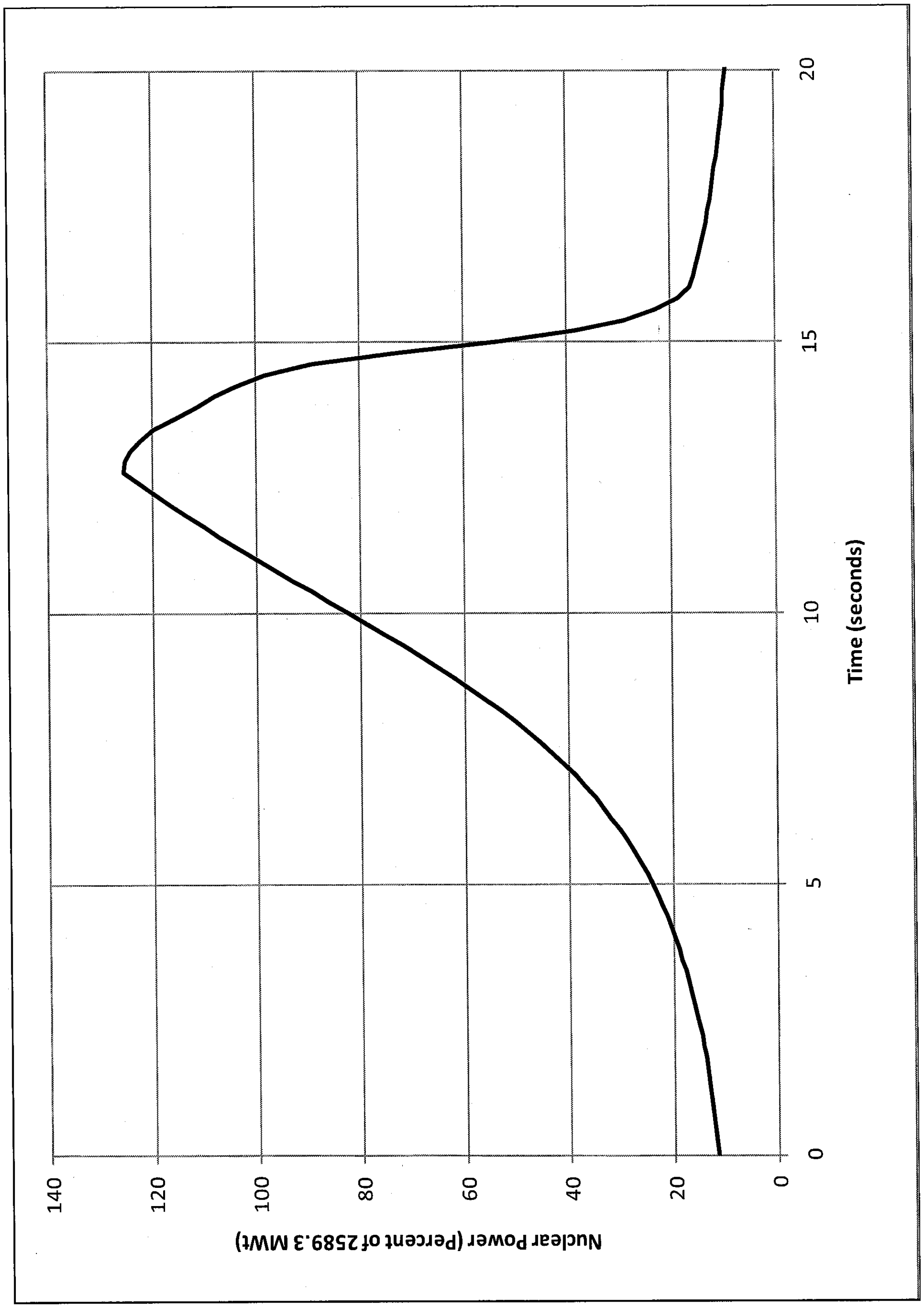
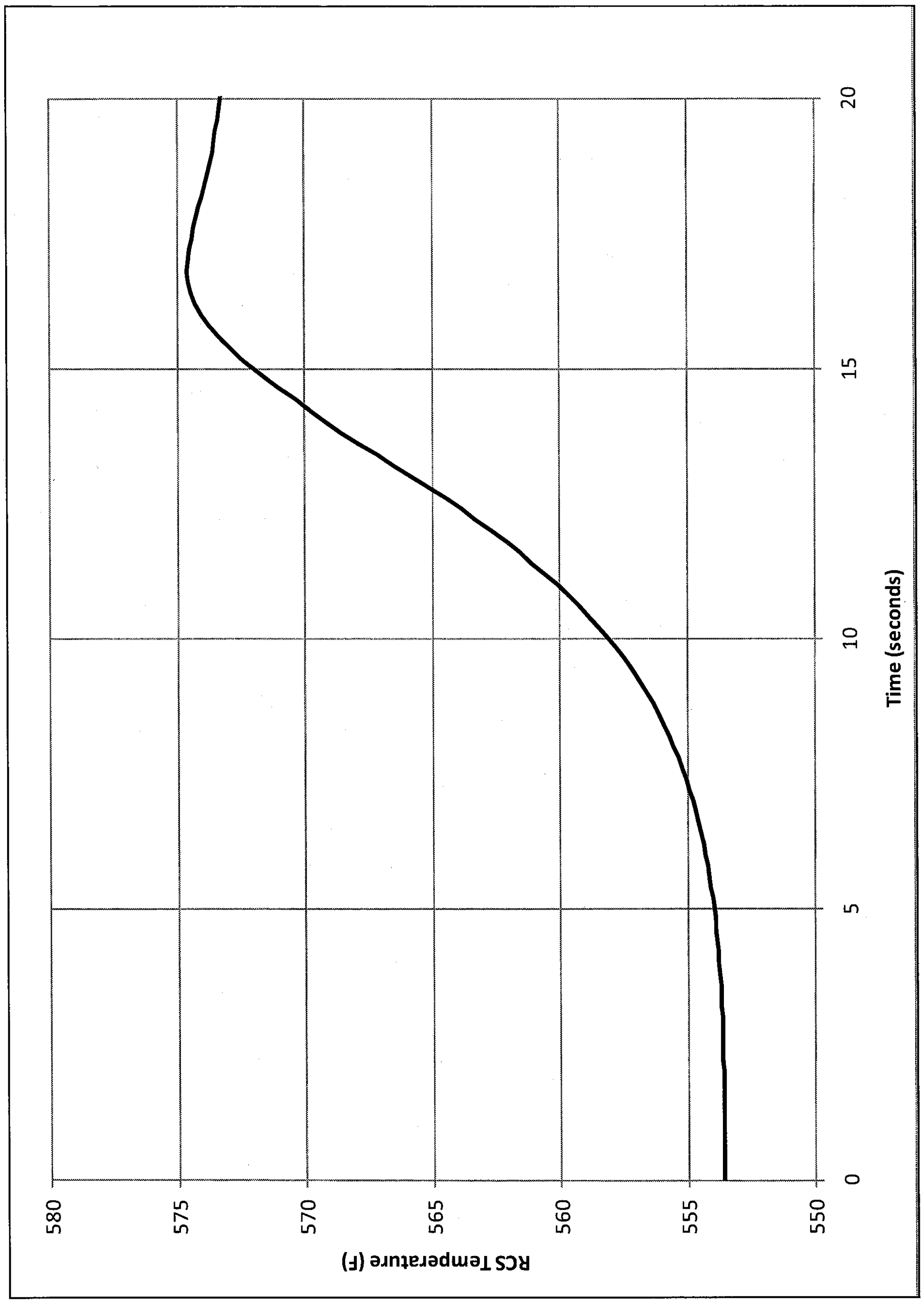


Figure 14.2-12
ROD WITHDRAWAL AT POWER
NUCLEAR POWER - RCS OVERPRESSURE CASE



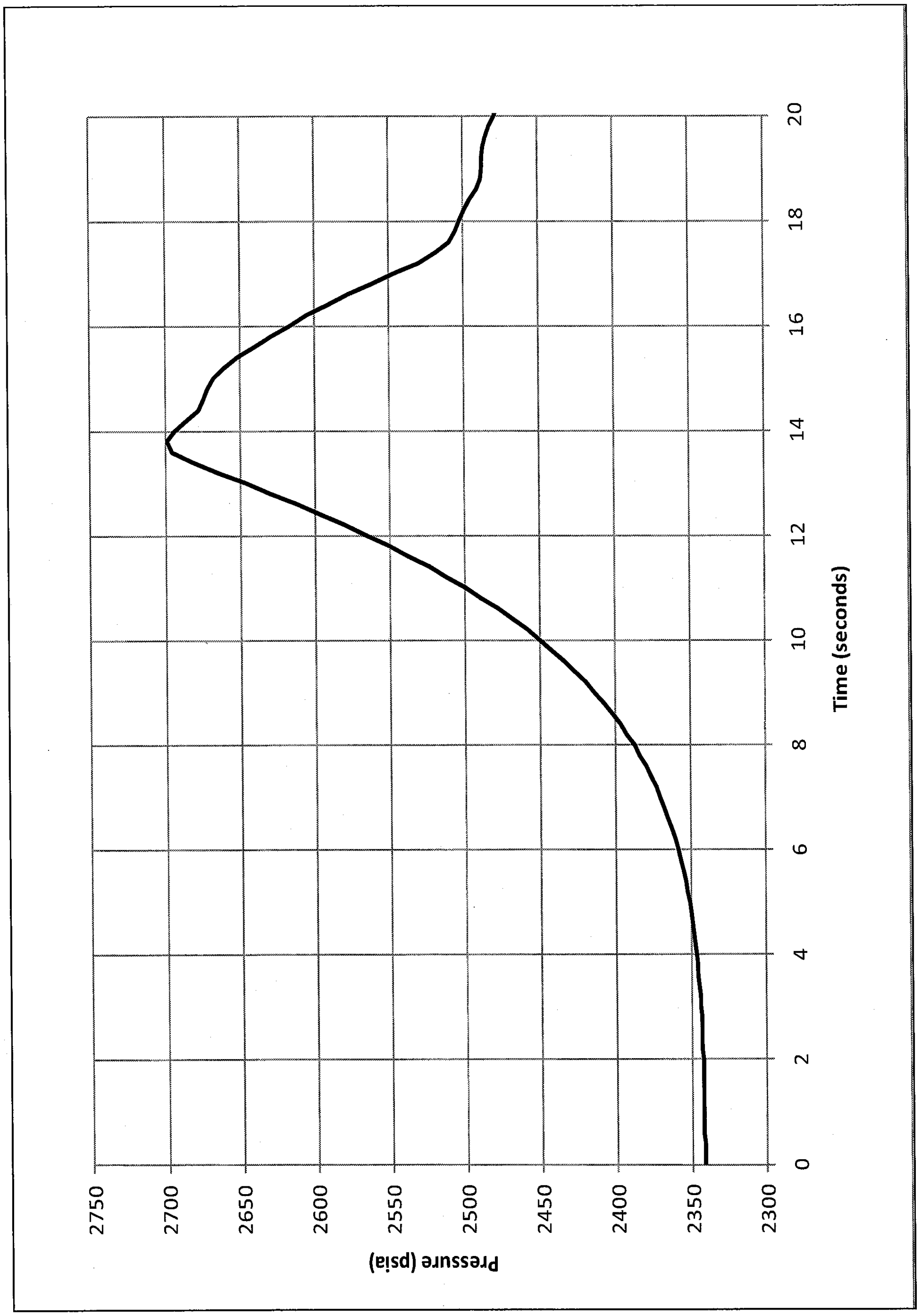
s1402011

Figure 14.2-13
ROD WITHDRAWAL AT POWER
RCS AVERAGE TEMPERATURE - RCS OVERPRESSURE CASE



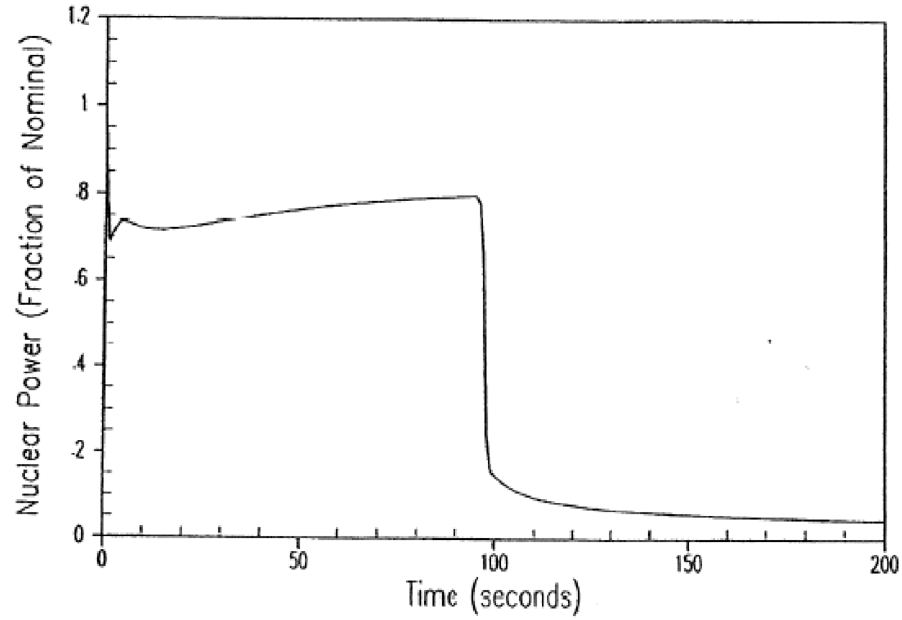
s1402012

Figure 14.2-14
ROD WITHDRAWAL AT POWER COLD LEG PRESSURE - RCS OVERPRESSURE CASE



s1402013

Figure 14.2-15
NUCLEAR POWER AND CORE HEAT FLUX
TRANSIENTS FOR DROPPED RCCA, MANUAL CONTROL



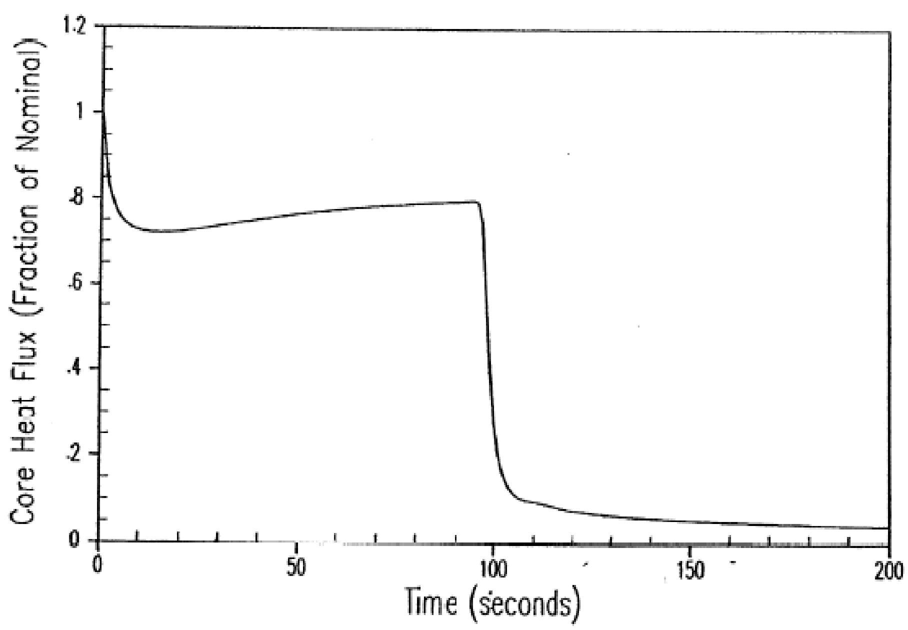
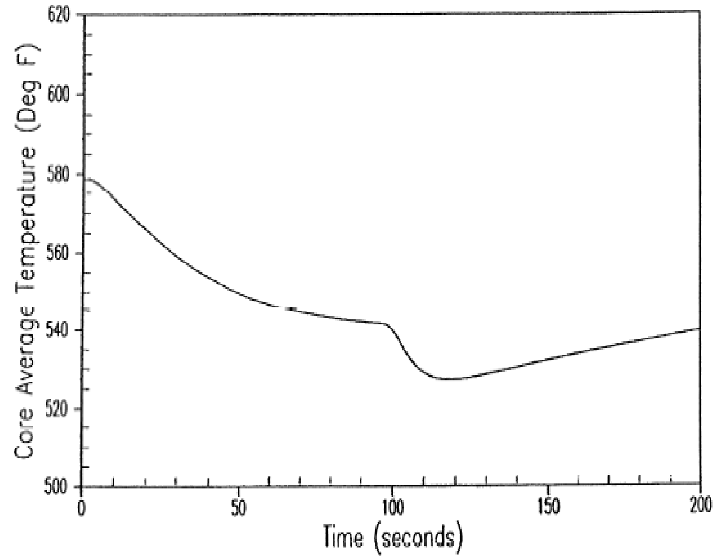


Figure 14.2-16
CORE AVG. TEMPERATURE AND PRESSURIZER PRESSURE
TRANSIENTS FOR DROPPED RCCA, MANUAL CONTROL



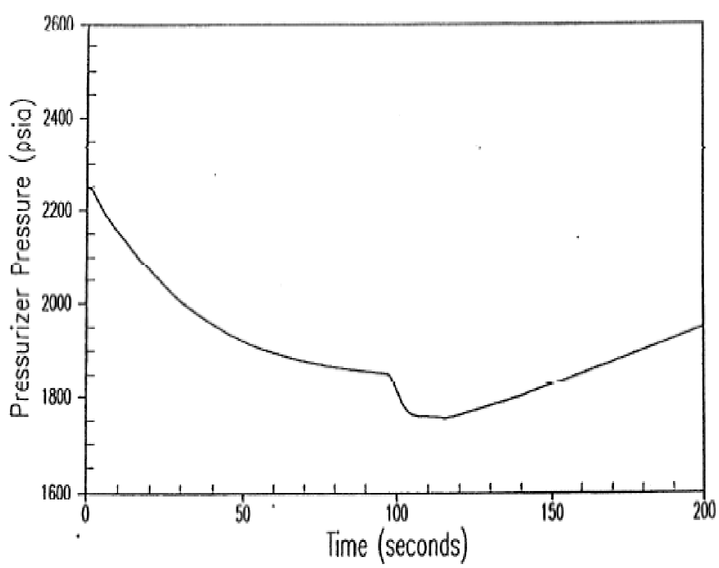


Figure 14.2-17
SURRY MLT-LOOP EXCESS FW TRANSIENT (150% FLOW W/ROD CONTROL) -
NUCLEAR POWER, FRACTION OF 2546 MWt

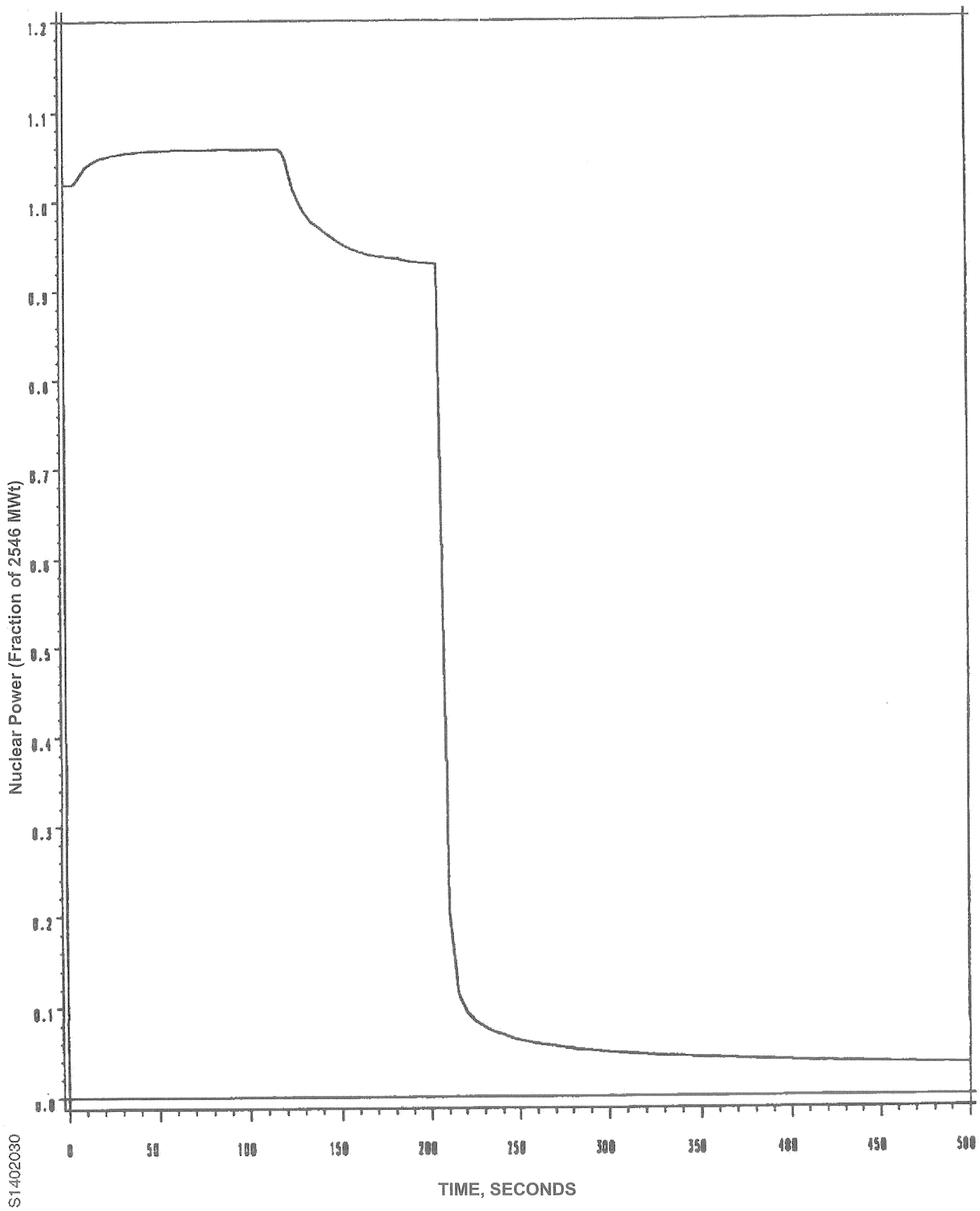


Figure 14.2-18
SURRY MLT-LOOP EXCESS FW TRANSIENT (150% FLOW W/ROD CONTROL) - LOOP ΔT, DEG F

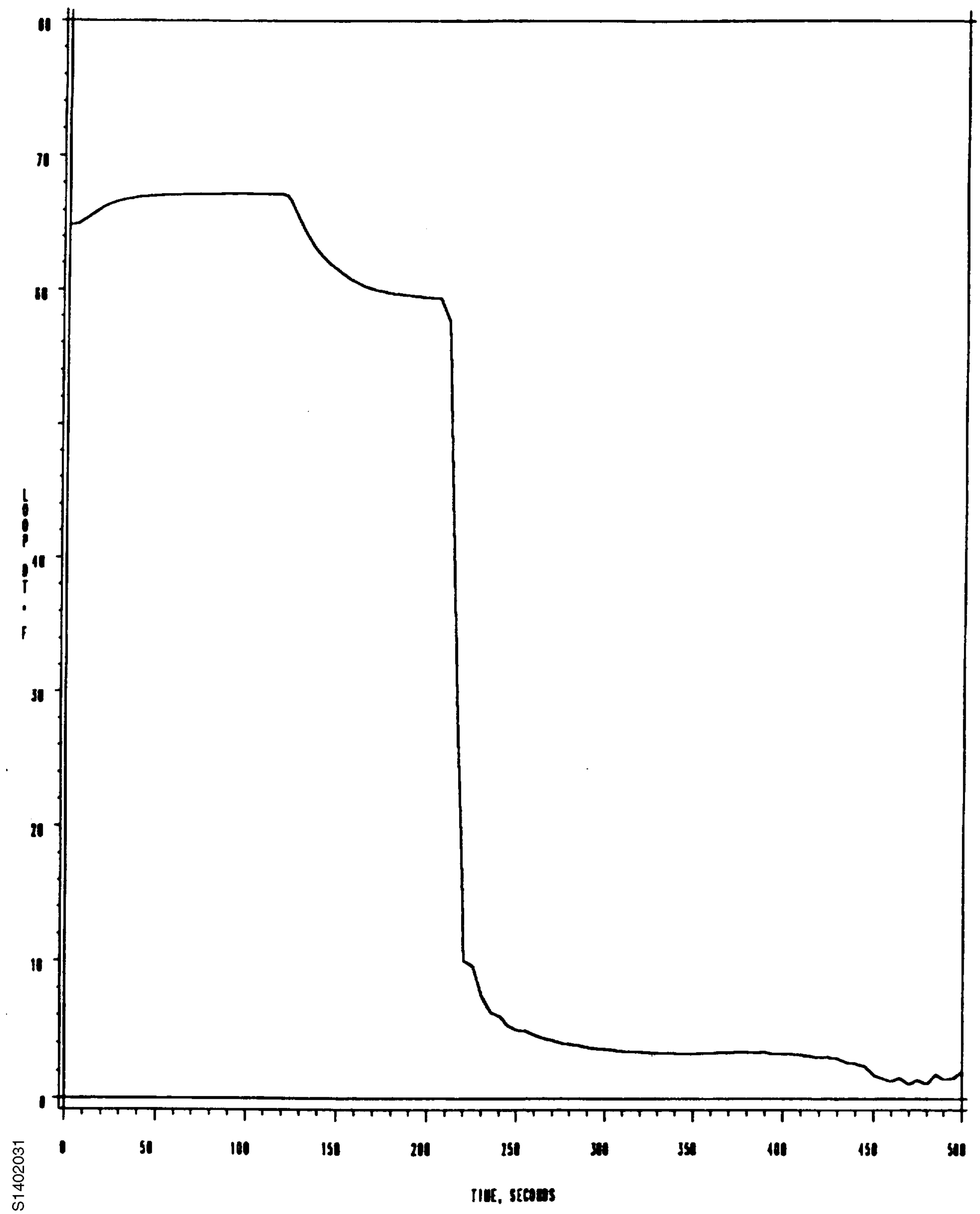


Figure 14.2-19
SURRY MLT-LOOP EXCESS FW TRANSIENT (150% FLOW W/ROD CONTROL) -
PRESSURIZER PRESSURE, PSIA

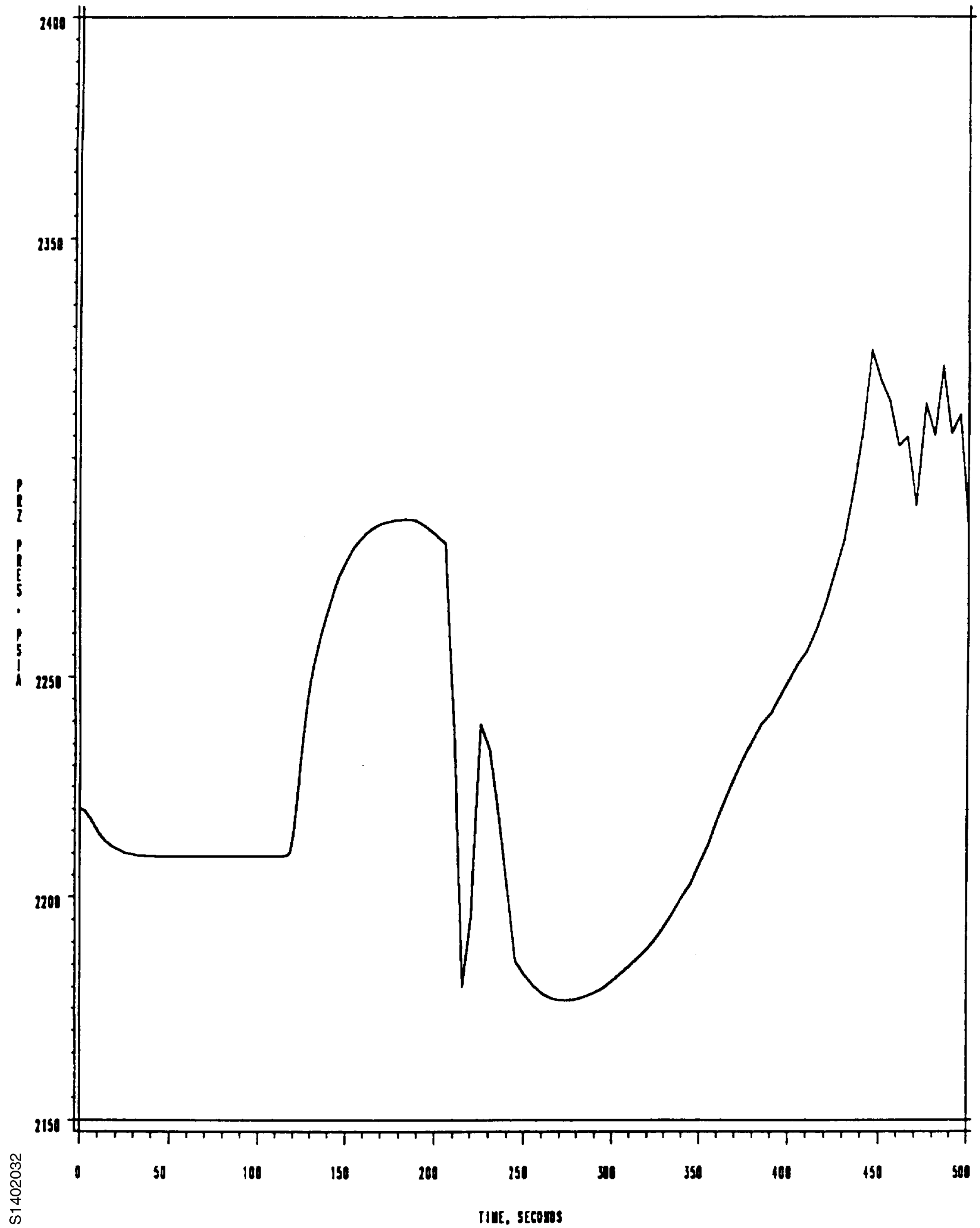


Figure 14.2-20
SURRY MLT-LOOP EXCESS FW TRANSIENT (150% FLOW W/ROD CONTROL) - CORE AVG TEMPERATURE, °F

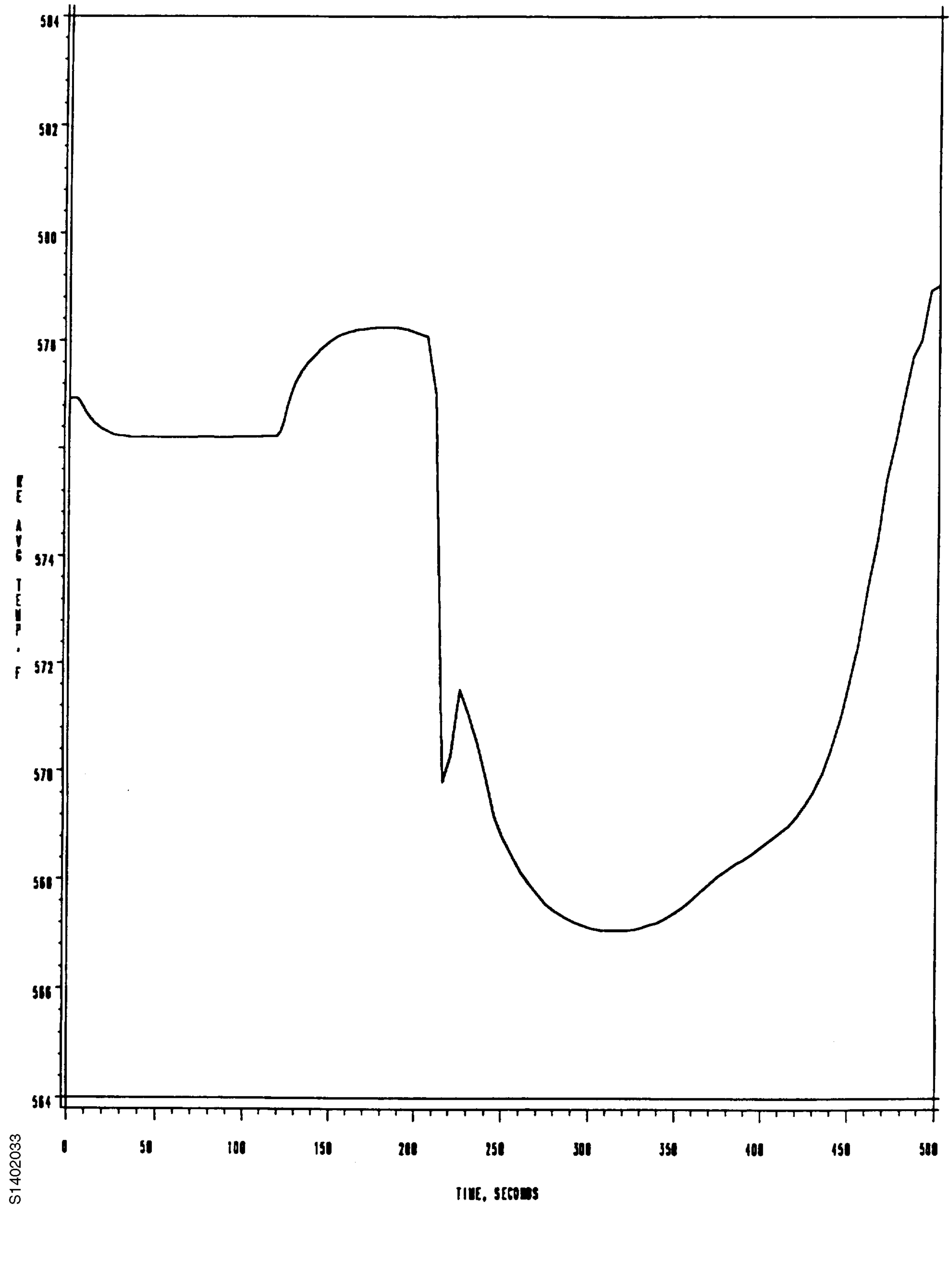
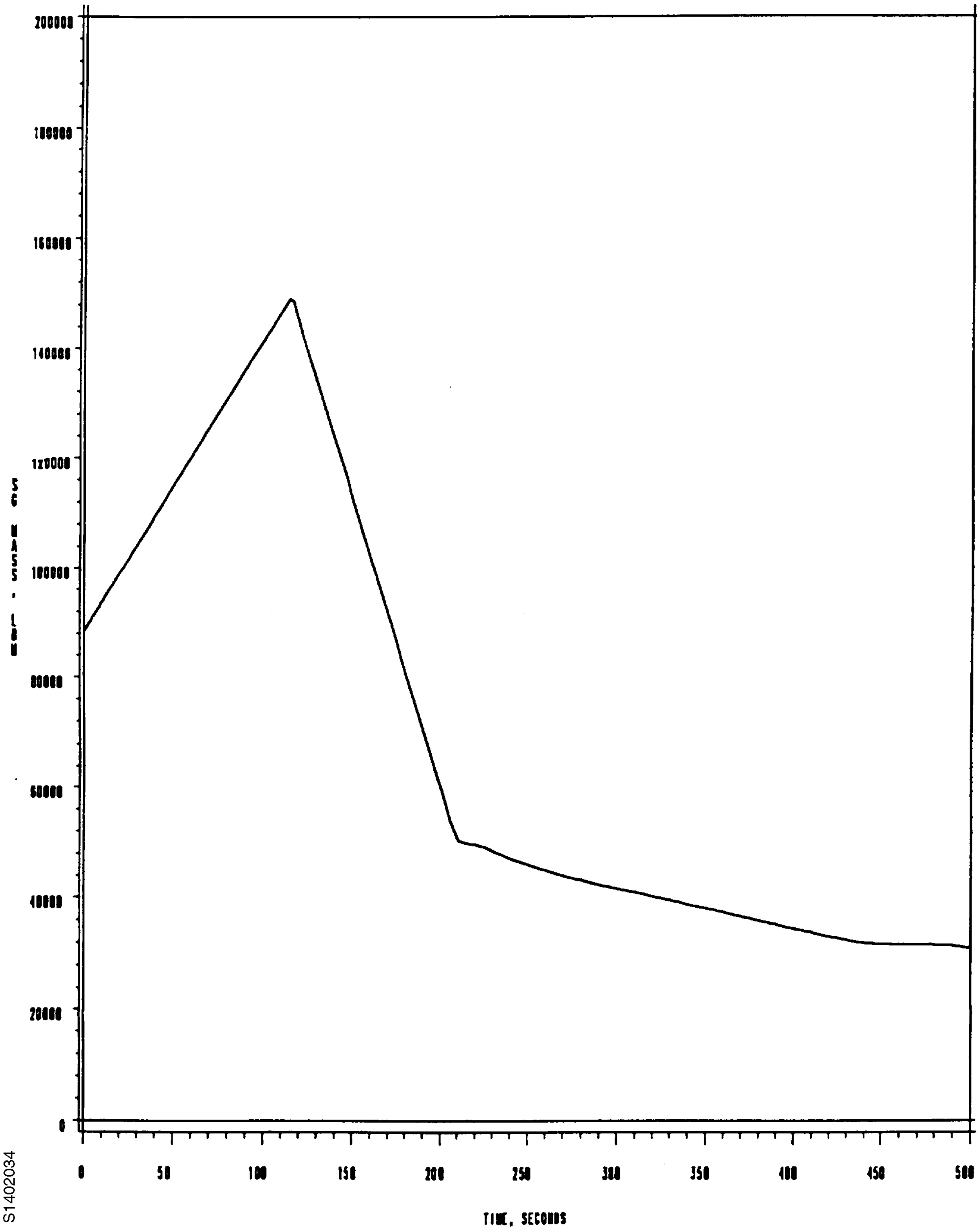


Figure 14.2-21
SURRY MLT-LOOP EXCESS FW TRANSIENT (150% FLOW W/ROD CONTROL) -
STEAM GENERATOR MASS, LBM



S1402034

Figure 14.2-22
MAIN FEEDWATER TEMPERATURE REDUCTION EVENT
CHANGE IN FEEDWATER TEMPERATURE VS. TIME

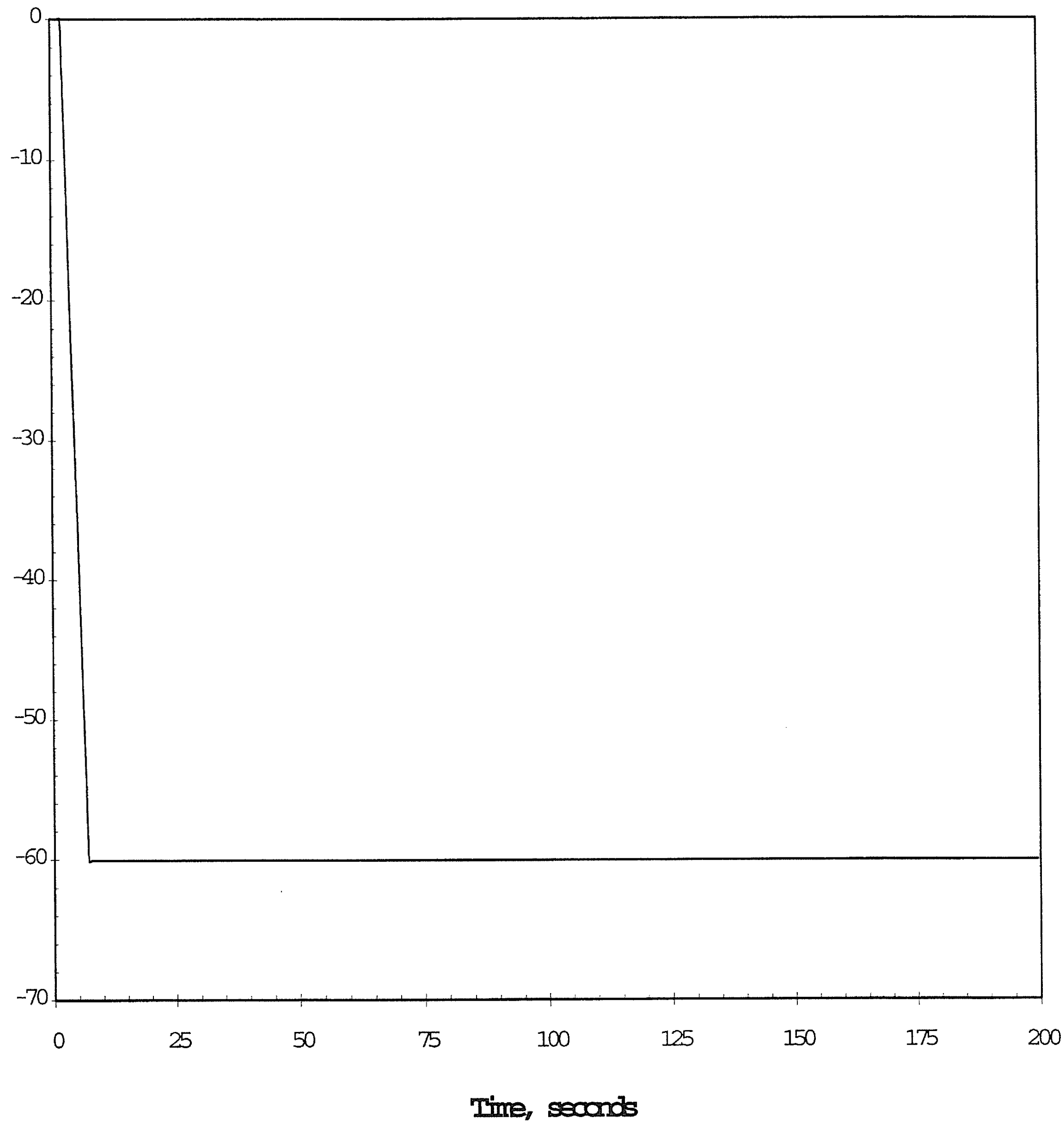


Figure 14.2-23
MAIN FEEDWATER TEMPERATURE REDUCTION EVENT
NORMALIZED POWER (FRACTION OF 2546 MWt) VS. TIME

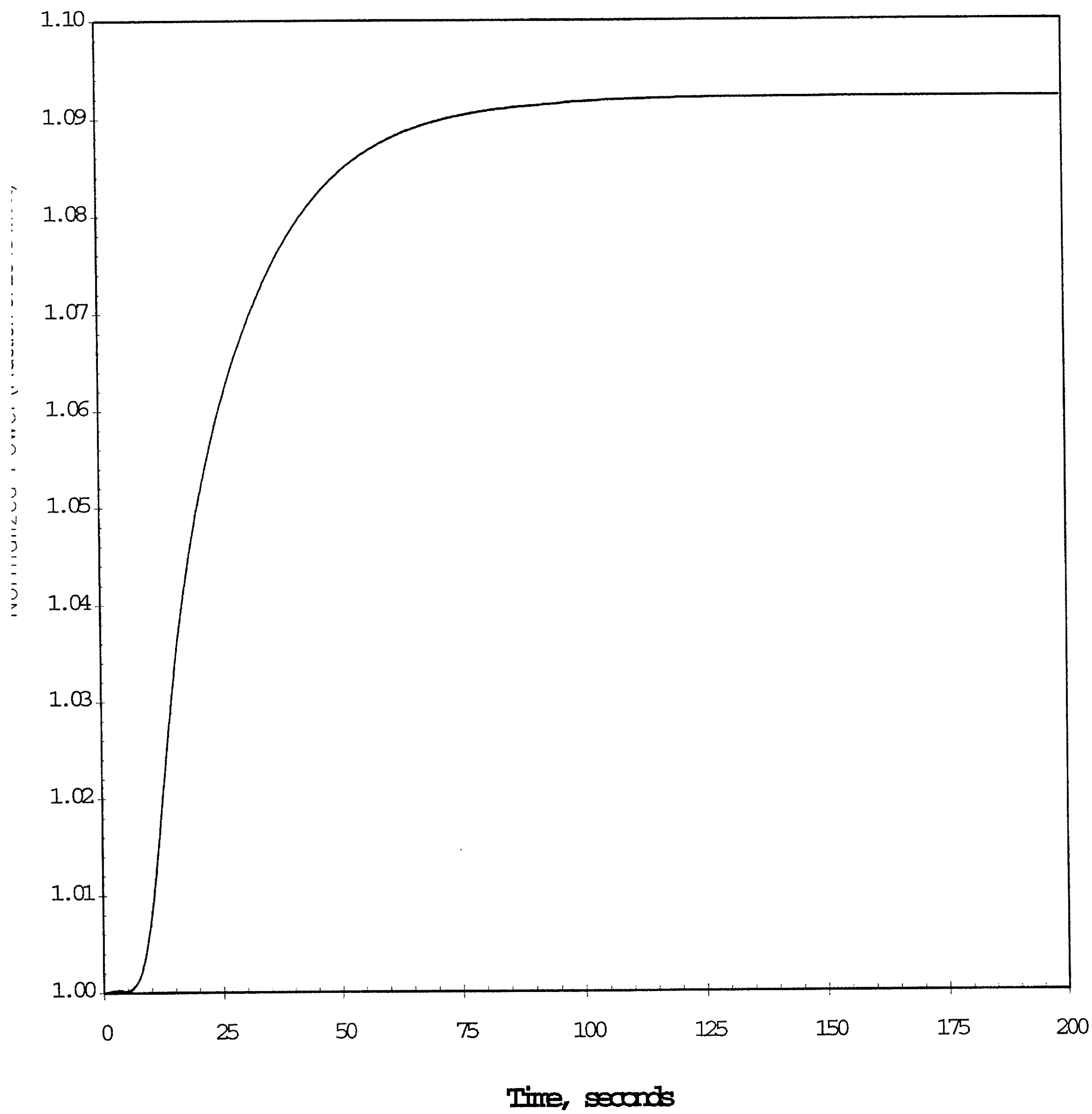


Figure 14.2-24
MAIN FEEDWATER TEMPERATURE REDUCTION EVENT
CHANGE IN PRESSURIZER PRESSURE VS. TIME

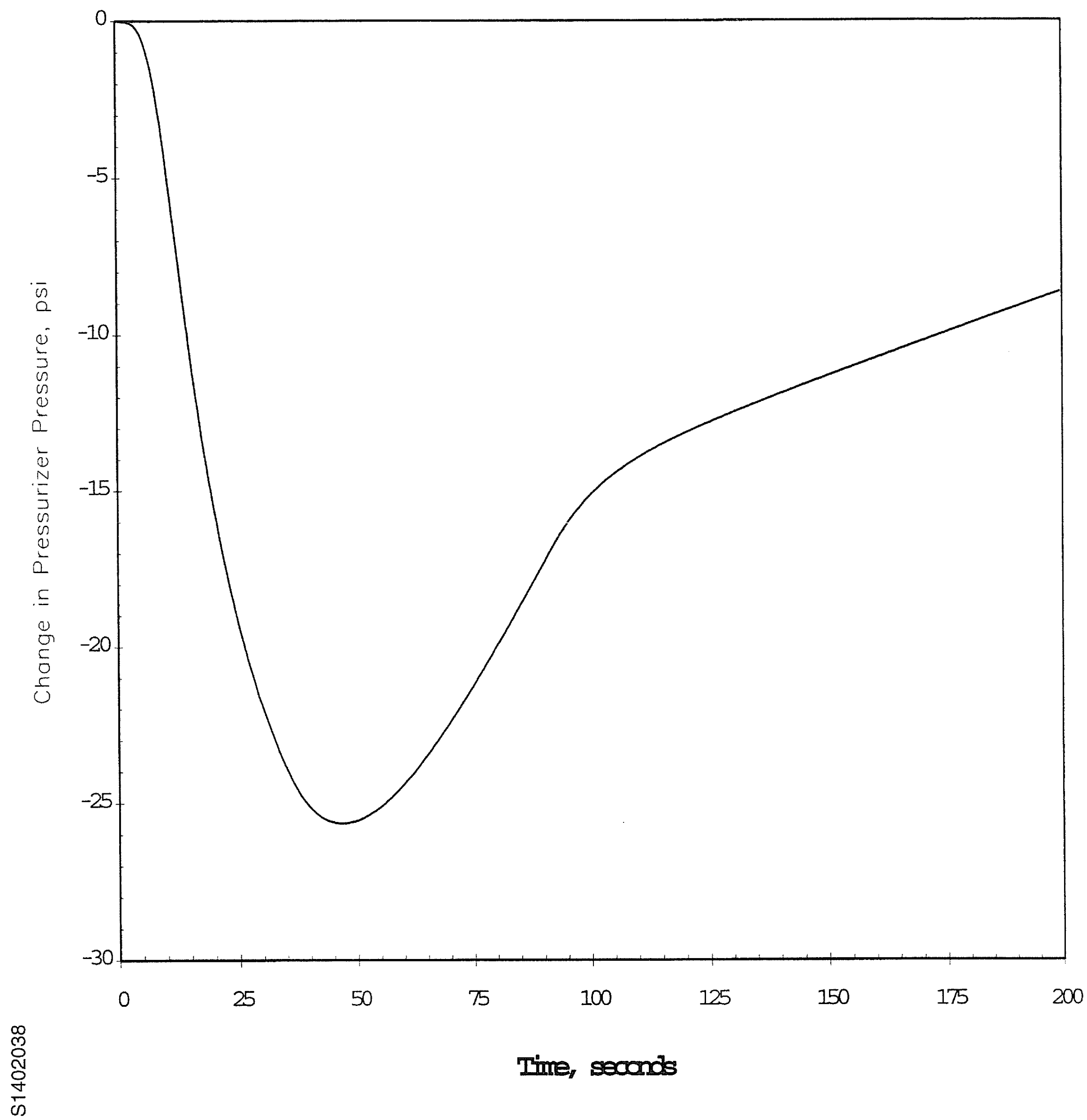


Figure 14.2-25
MAIN FEEDWATER TEMPERATURE REDUCTION EVENT
CHANGE IN RCS AVERAGE TEMPERATURE VS. TIME

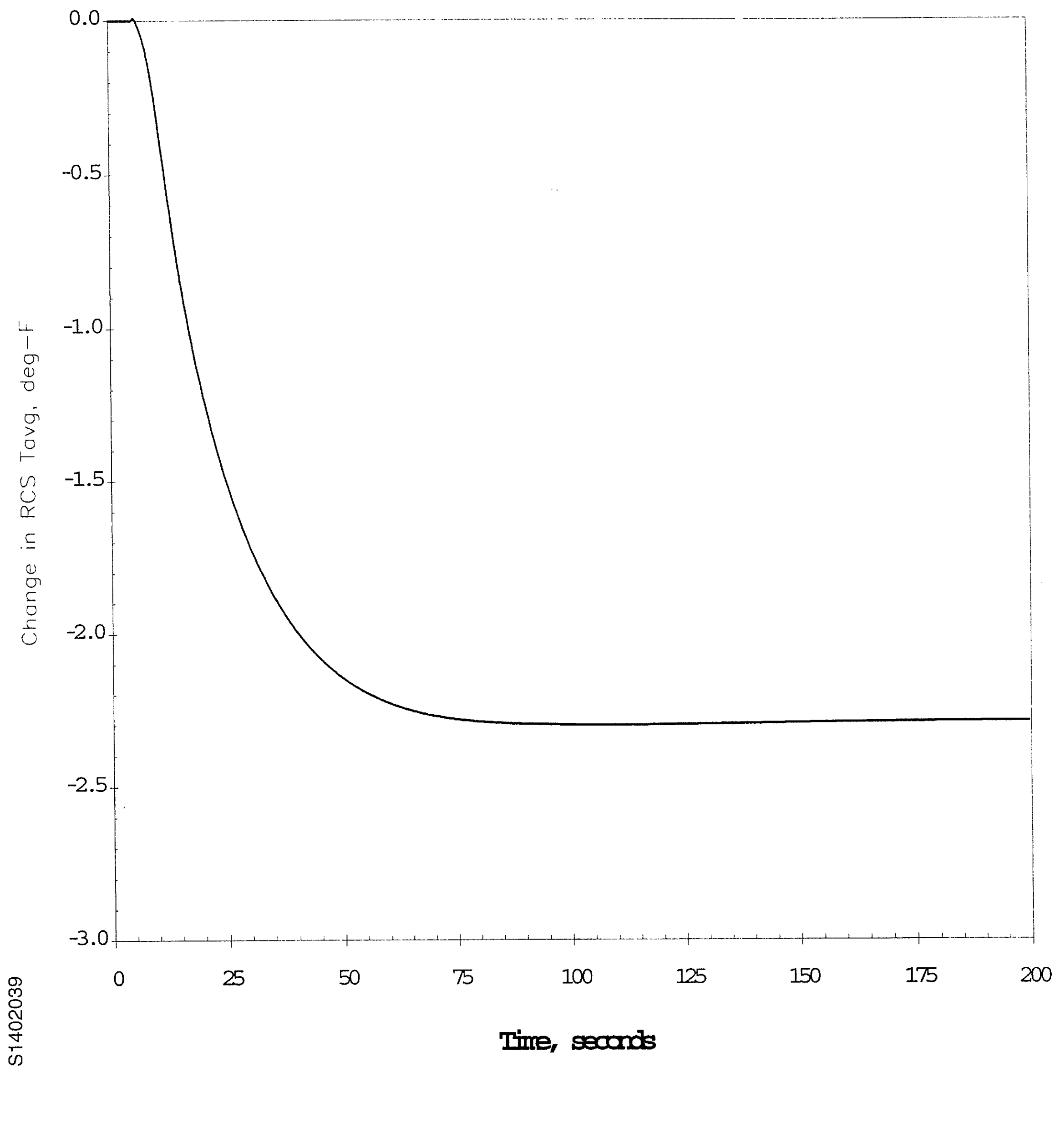


Figure 14.2-26
MAIN FEEDWATER TEMPERATURE REDUCTION EVENT
CHANGE IN RCS LOOP DELTA-T VS. TIME

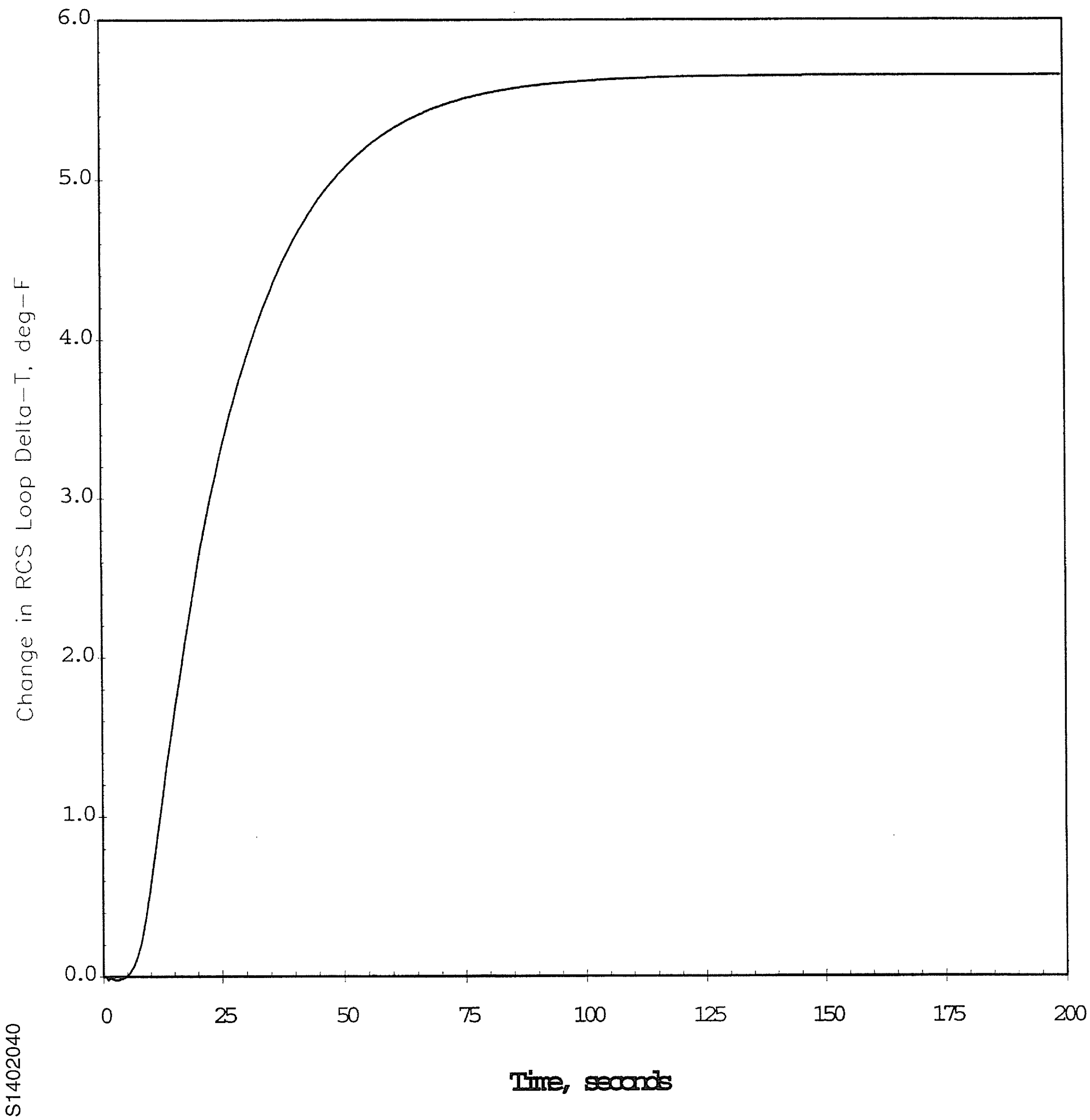


Figure 14.2-27
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW
(AT 2546 MWt) RC OFF (SELITURB) NUCLEAR POWER (% OF 2546 MWt)

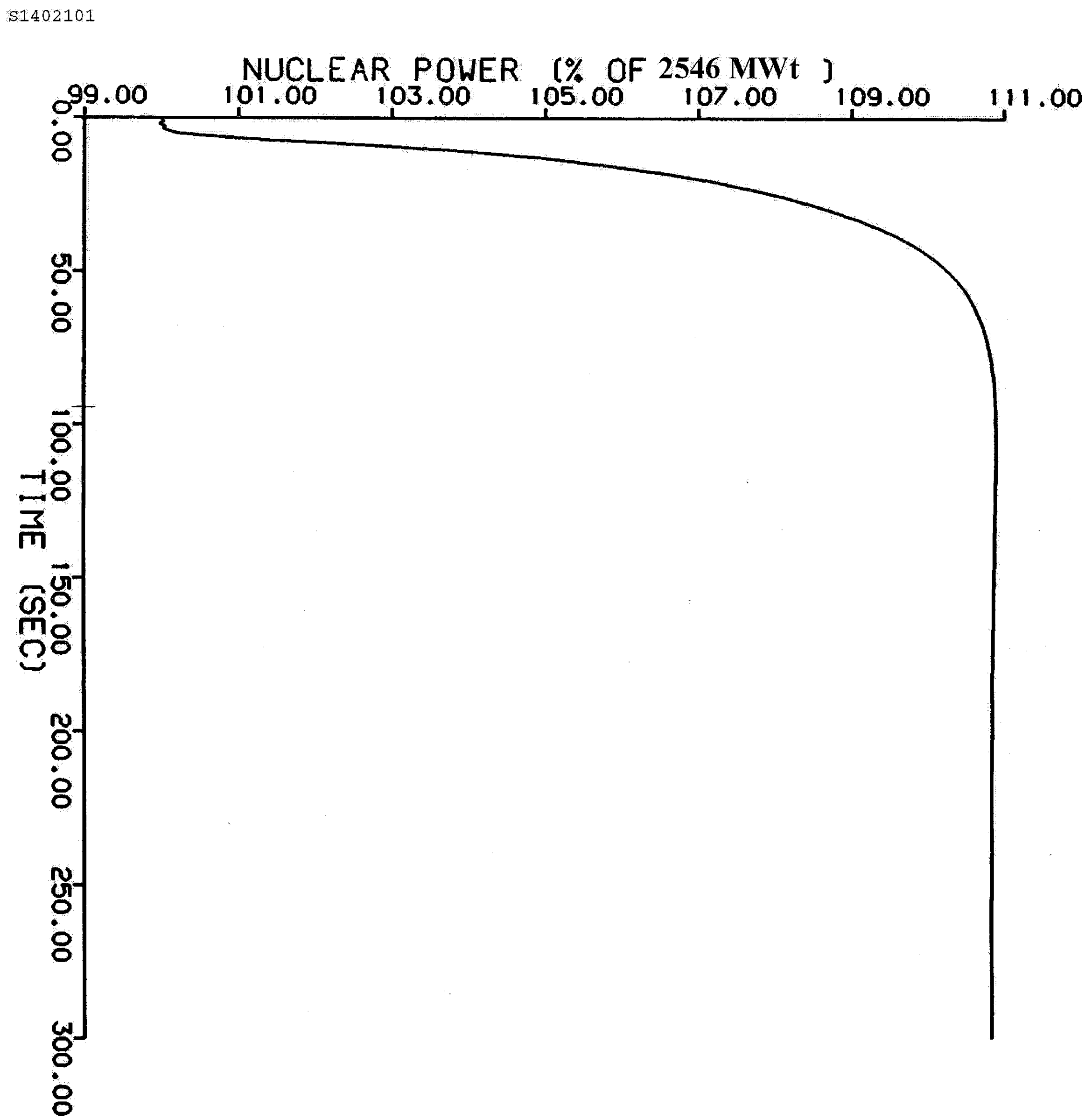


Figure 14.2-28
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW
(AT 2546 MWt) RC OFF (SELITURB) CHANGE IN PRESSURIZER PRESSURE

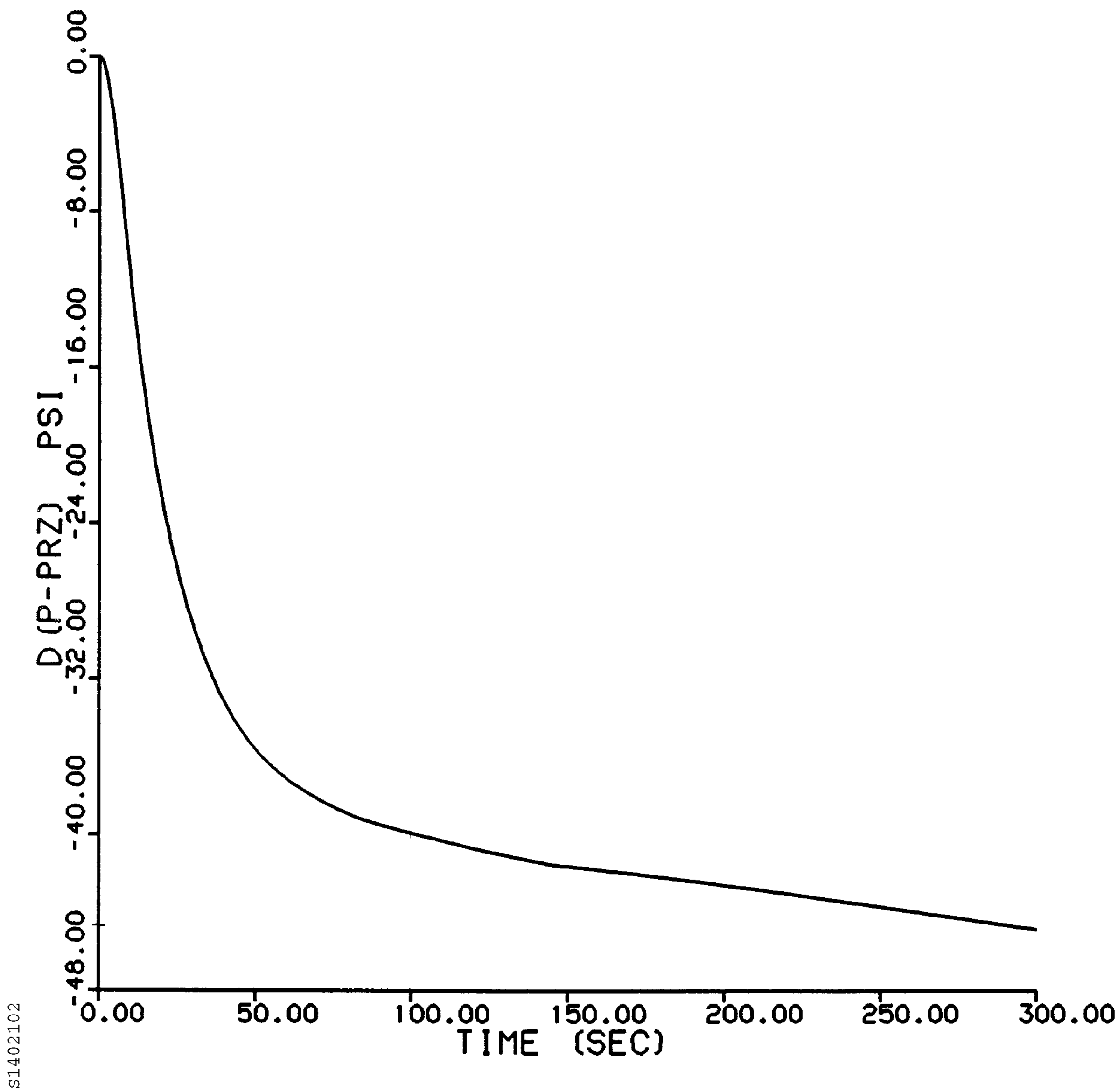


Figure 14.2-29
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW (AT 2546 MWt) RC OFF (SELITURB) CHANGE IN T_{avg}

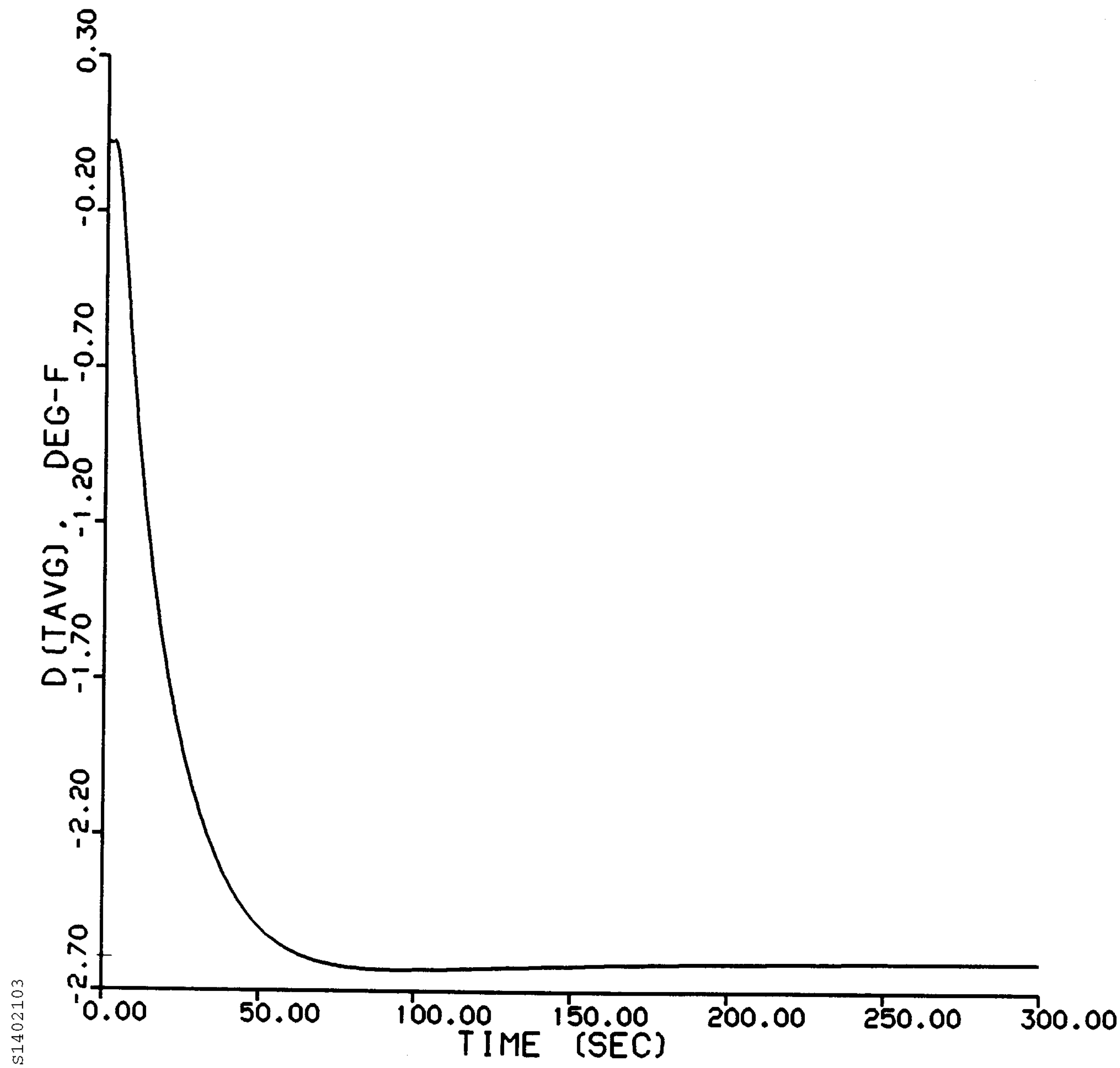


Figure 14.2-30
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW
(AT 2546 MWt) RC OFF (SELITURB) CHANGE IN ΔT

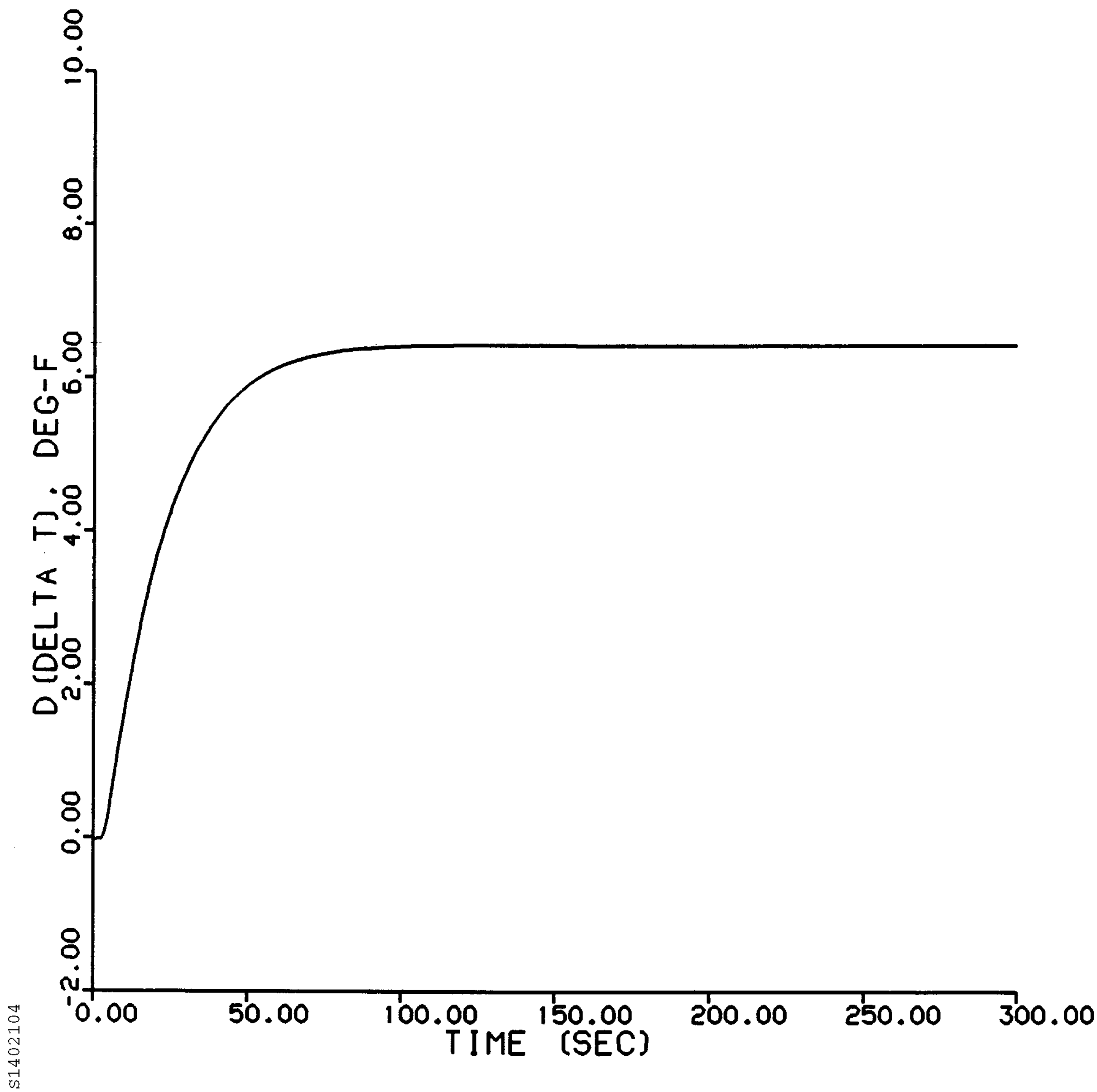


Figure 14.2-31
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW
(AT 2546 MWt) RC ON (SELITRBR) NUCLEAR POWER (% OF 2546 MWt)

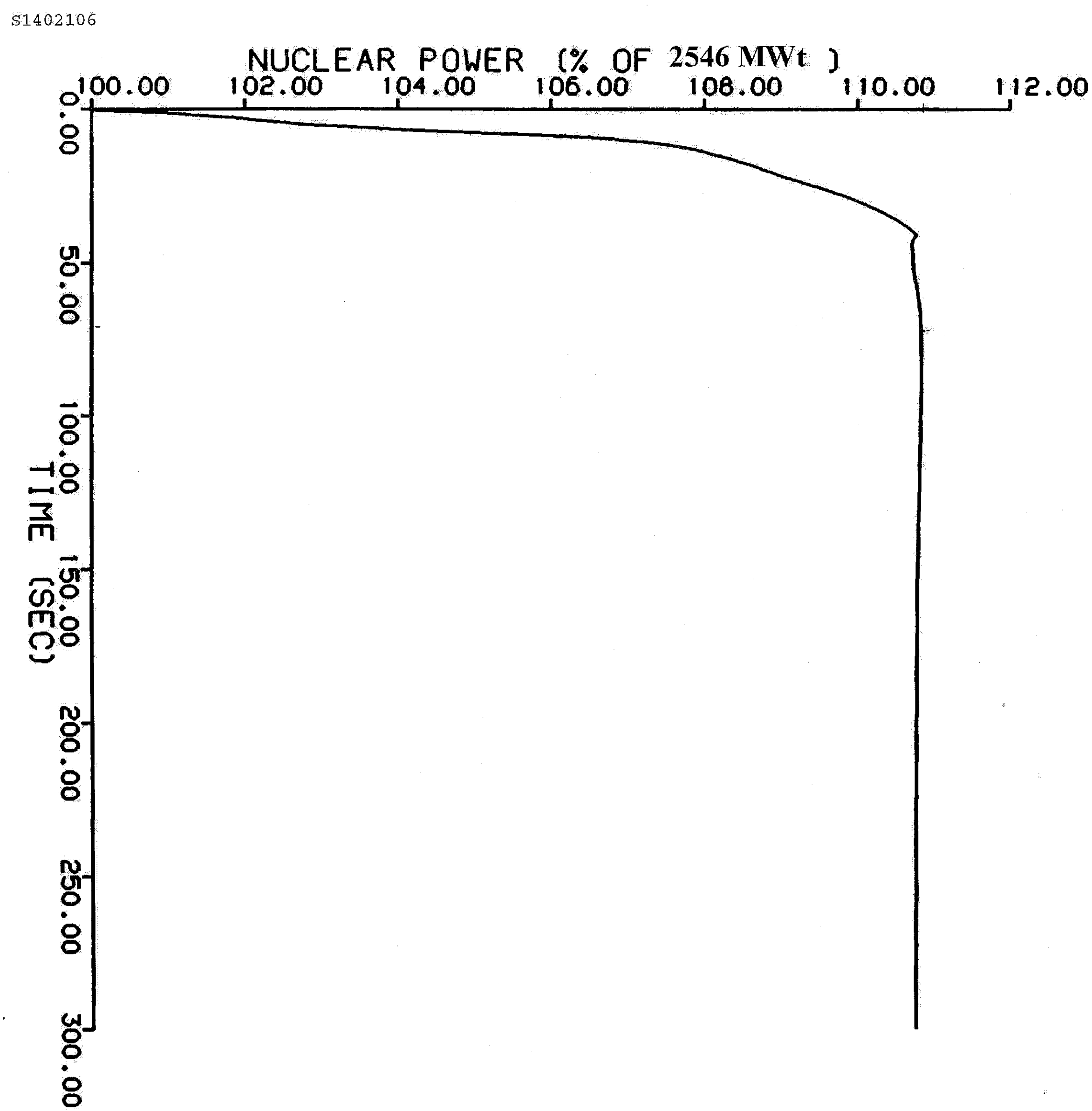


Figure 14.2-32
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW
(AT 2546 MWt) RC ON (SELITRBR) CHANGE IN PRESSURIZER PRESSURE

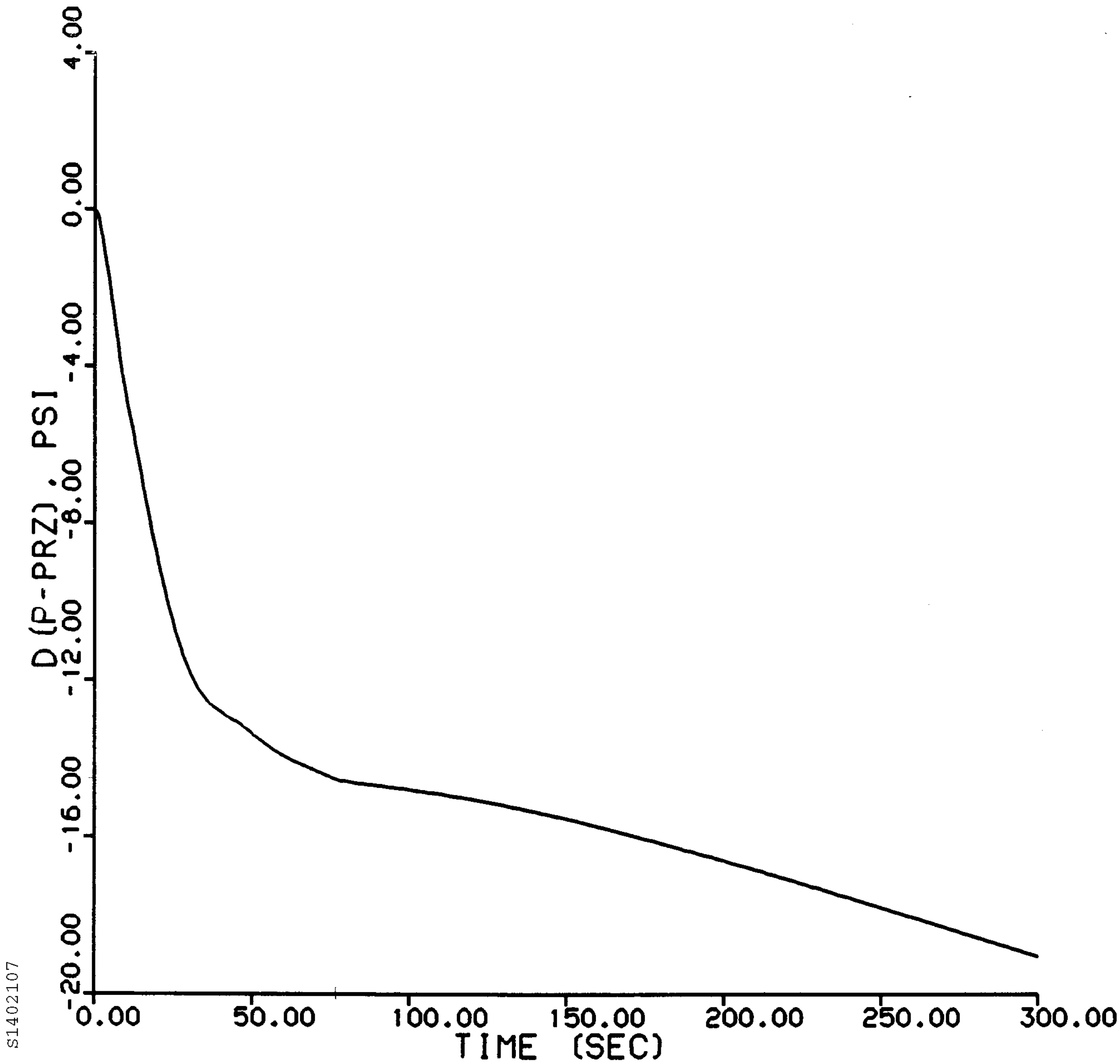


Figure 14.2-33
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW
(AT 2546 MWt) RC ON (SELITRBR) CHANGE IN T_{avg}

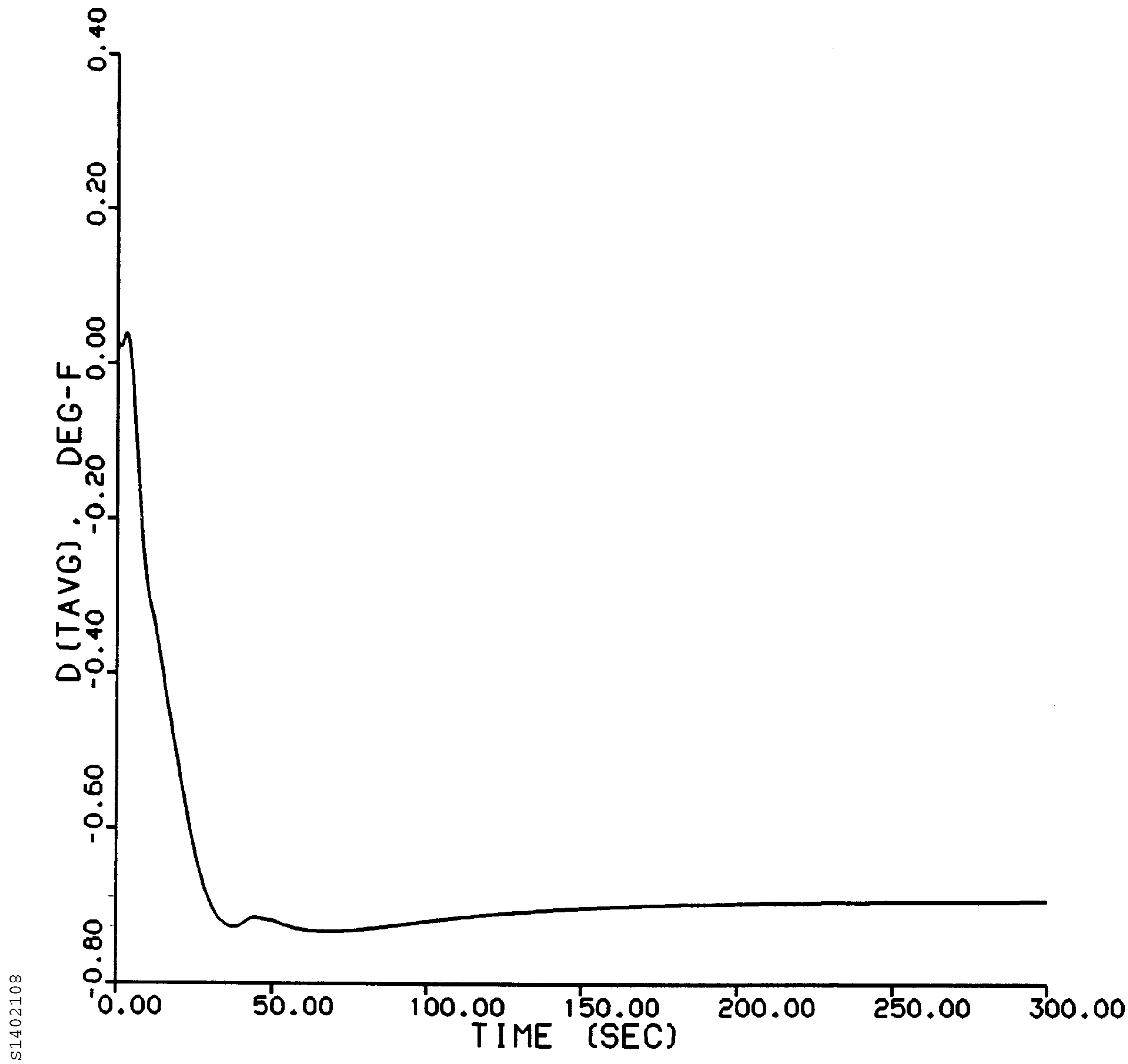


Figure 14.2-34
SURRY EXCESSIVE LOAD INCREASE HFP EOC 110% TURB FLOW
(AT 2546 MWt) RC ON (SELITRBR) CHANGE IN ΔT

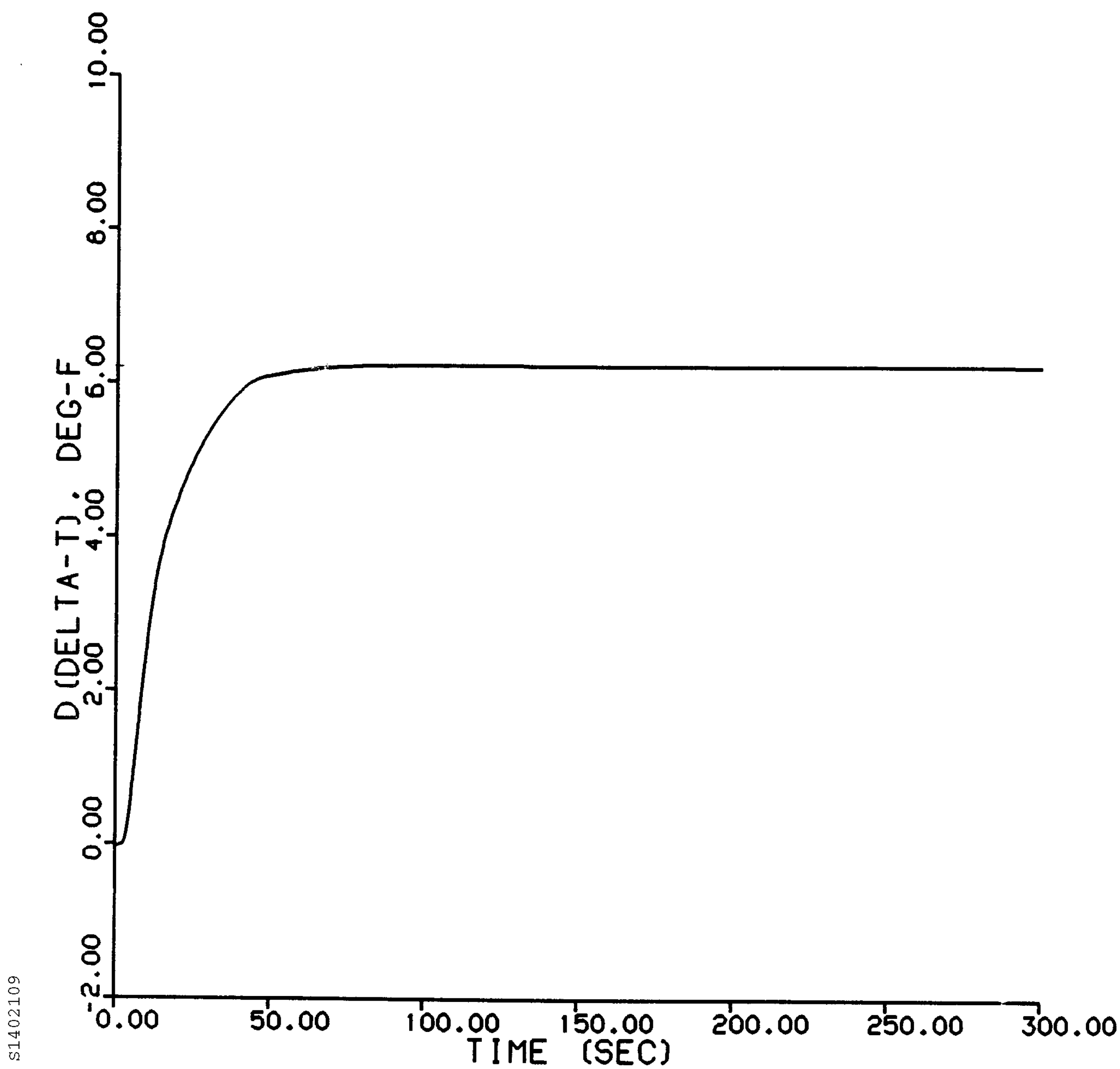


Figure 14.2-35
SURRY EXCESSIVE LOAD INCREASE HFP BOC 110% TURB FLOW
(AT 2546 MWt) (SELIBOCR) NUCLEAR POWER (% OF 2546 MWt)

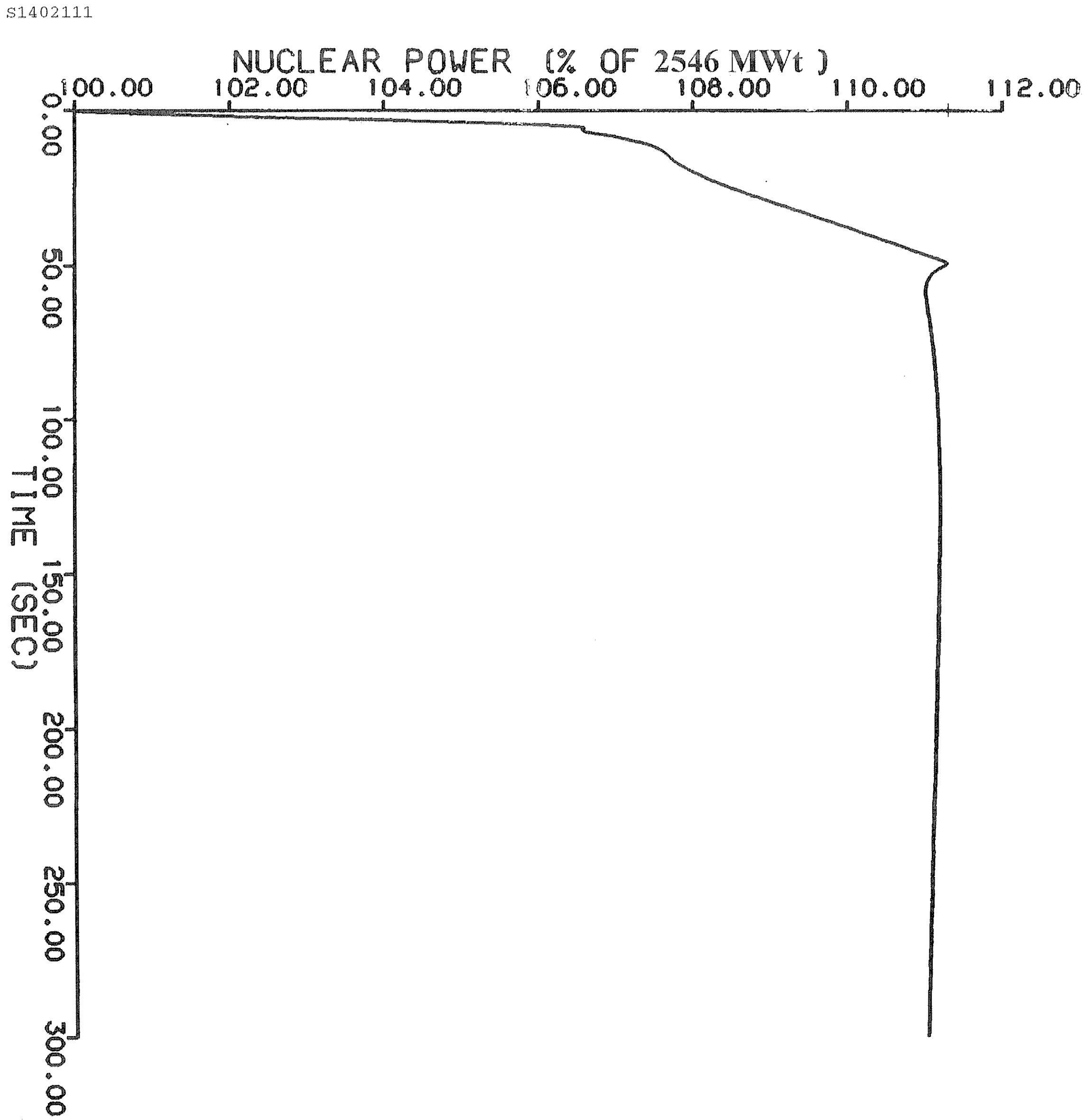


Figure 14.2-36
SURRY EXCESSIVE LOAD INCREASE HFP BOC 110% TURB FLOW
(AT 2546 MWt) (SELIBOCR) CHANGE IN PRESSURIZER PRESSURE

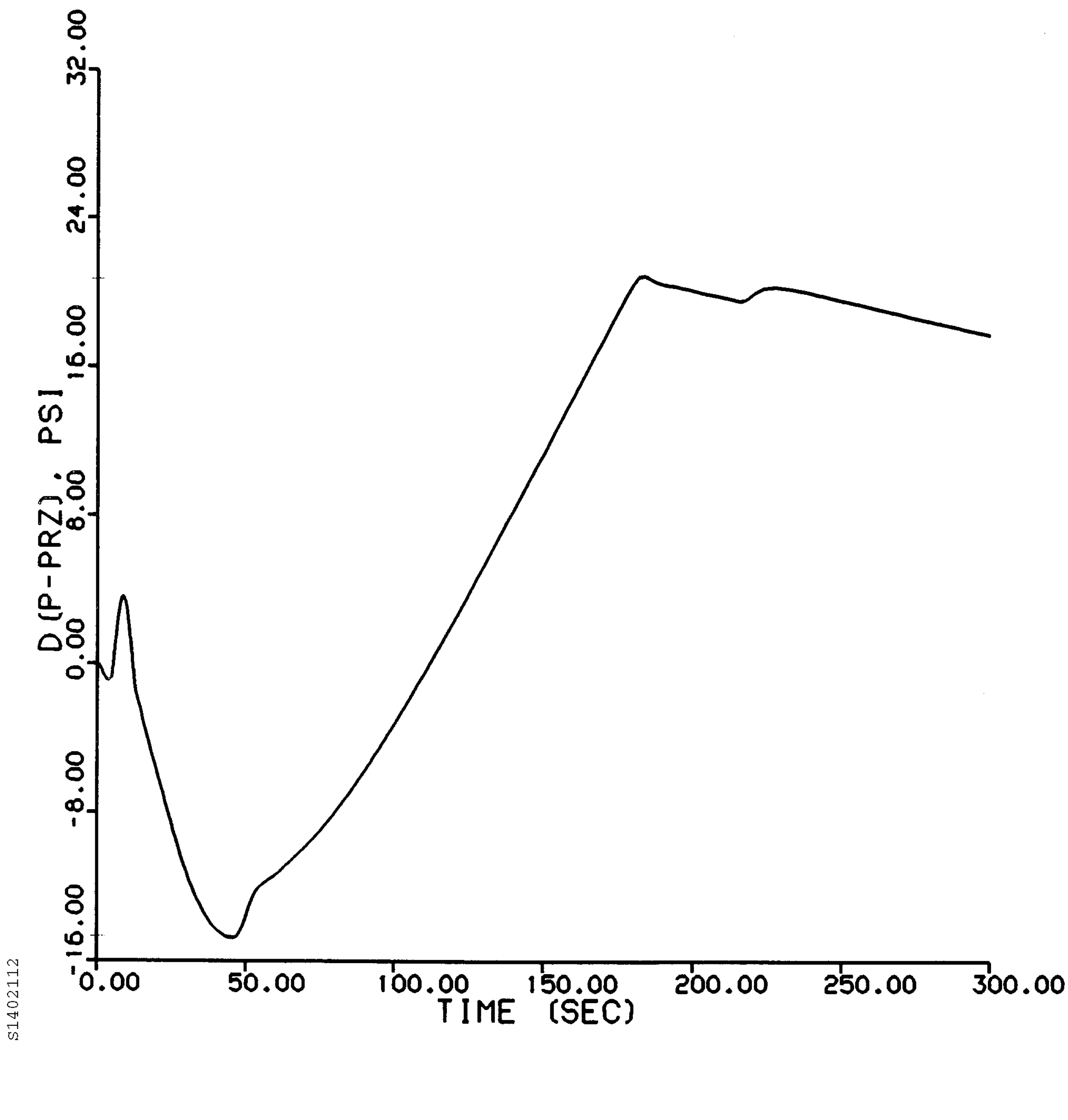
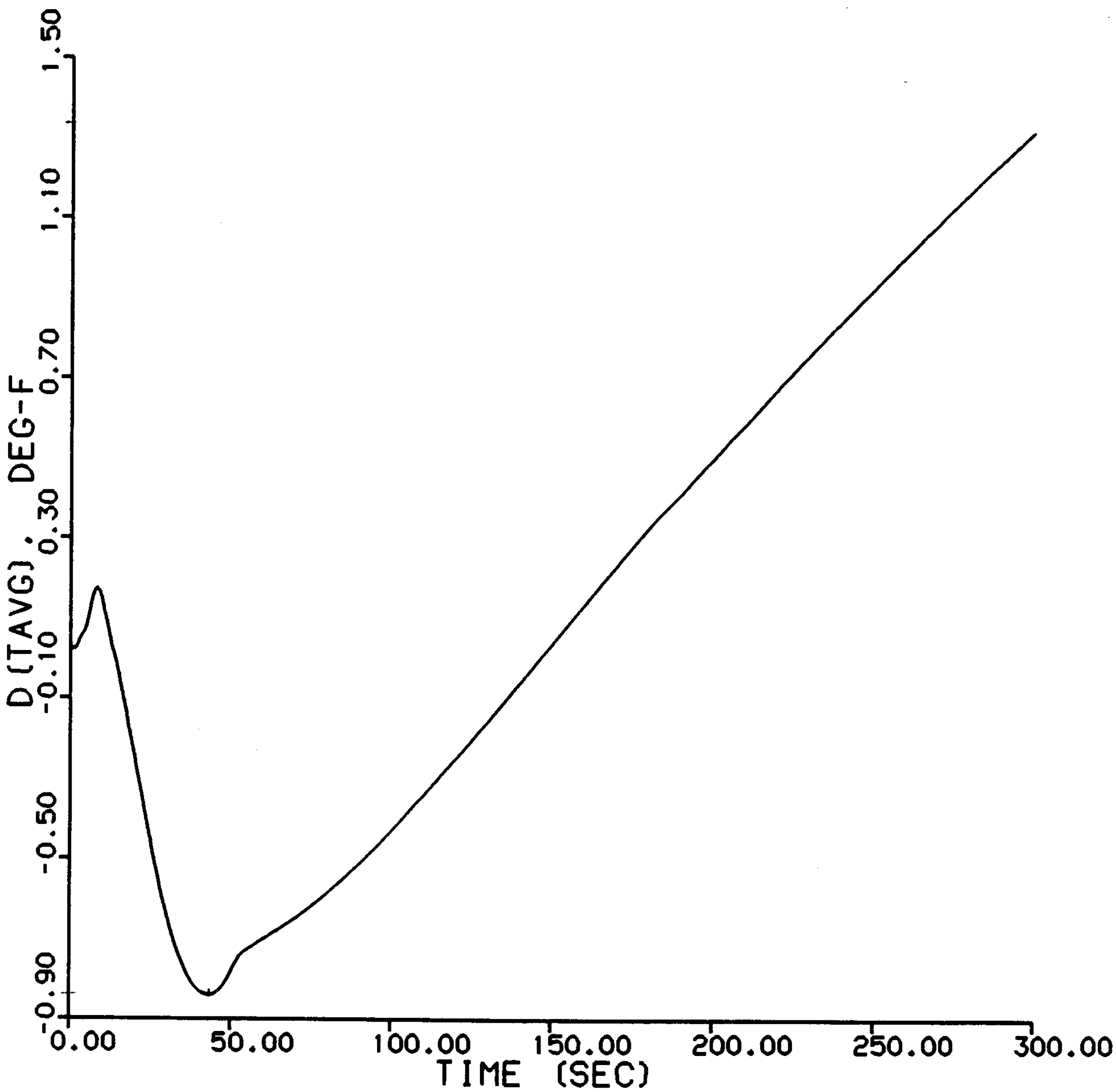


Figure 14.2-37
SURRY EXCESSIVE LOAD INCREASE HFP BOC 110% TURB FLOW
(AT 2546 MWt) (SELIBOCR) CHANGE IN T_{avg}



S1402113

Figure 14.2-38
SURRY EXCESSIVE LOAD INCREASE HFP BOC 110% TURB FLOW
(AT 2546 MWt) (SELIBOCR) CHANGE IN ΔT

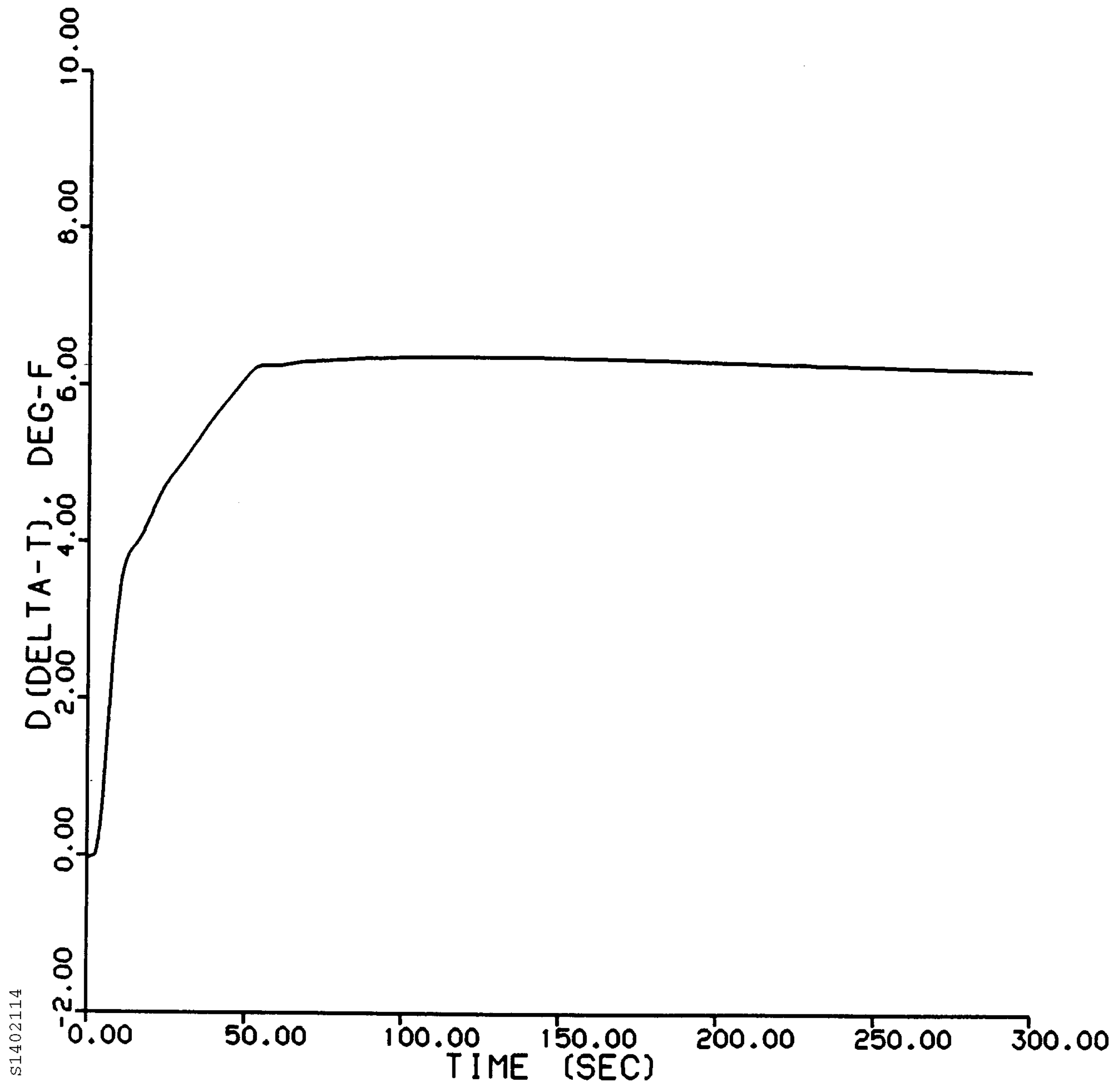


Figure 14.2-39
COMPLETE LOSS OF FLOW - UNDERVOLTAGE CASE RCS MASS FLOW RATE

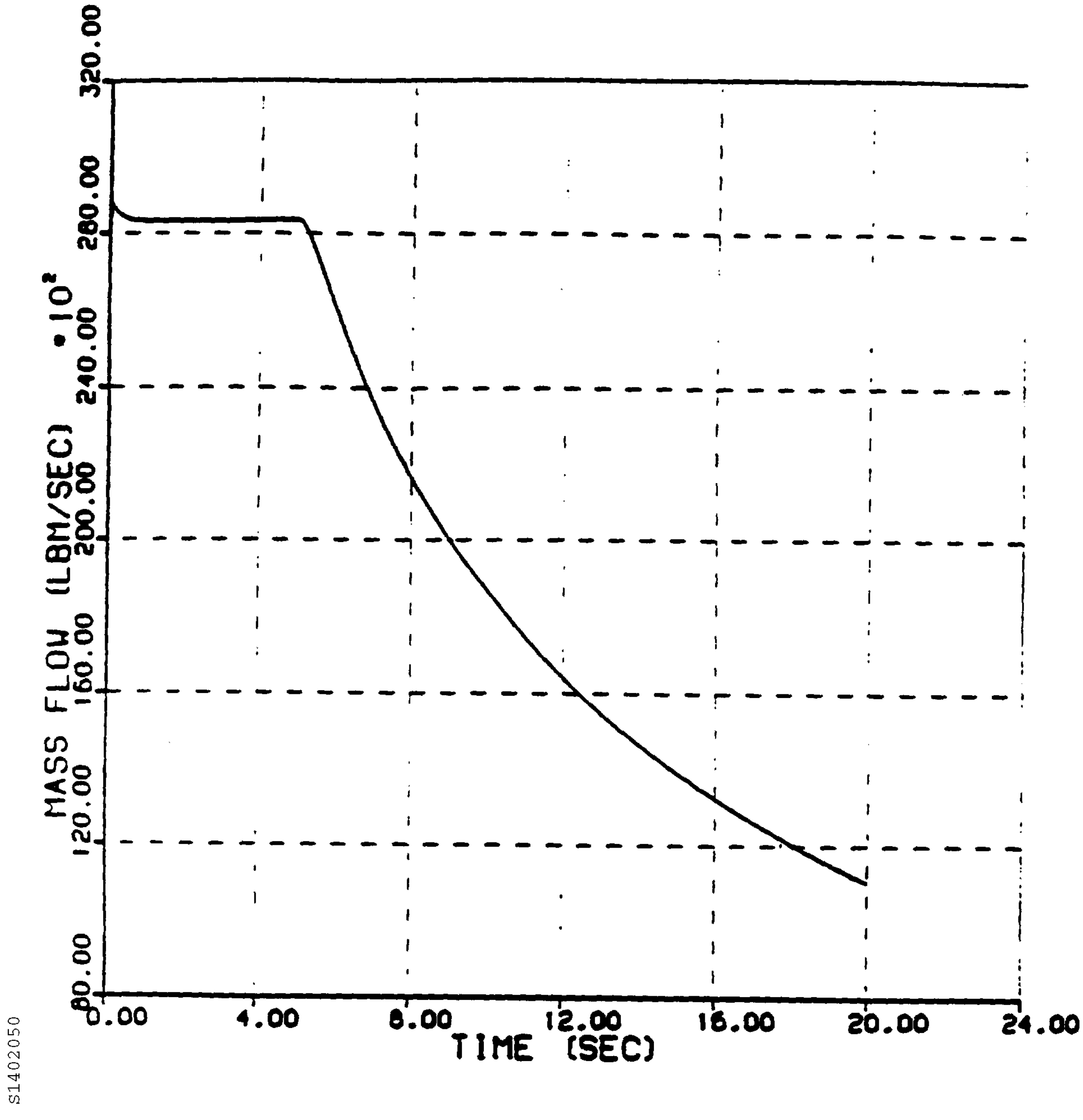


Figure 14.2-40
COMPLETE LOSS OF FLOW - UNDERFREQUENCY CASE RCS MASS FLOW RATE

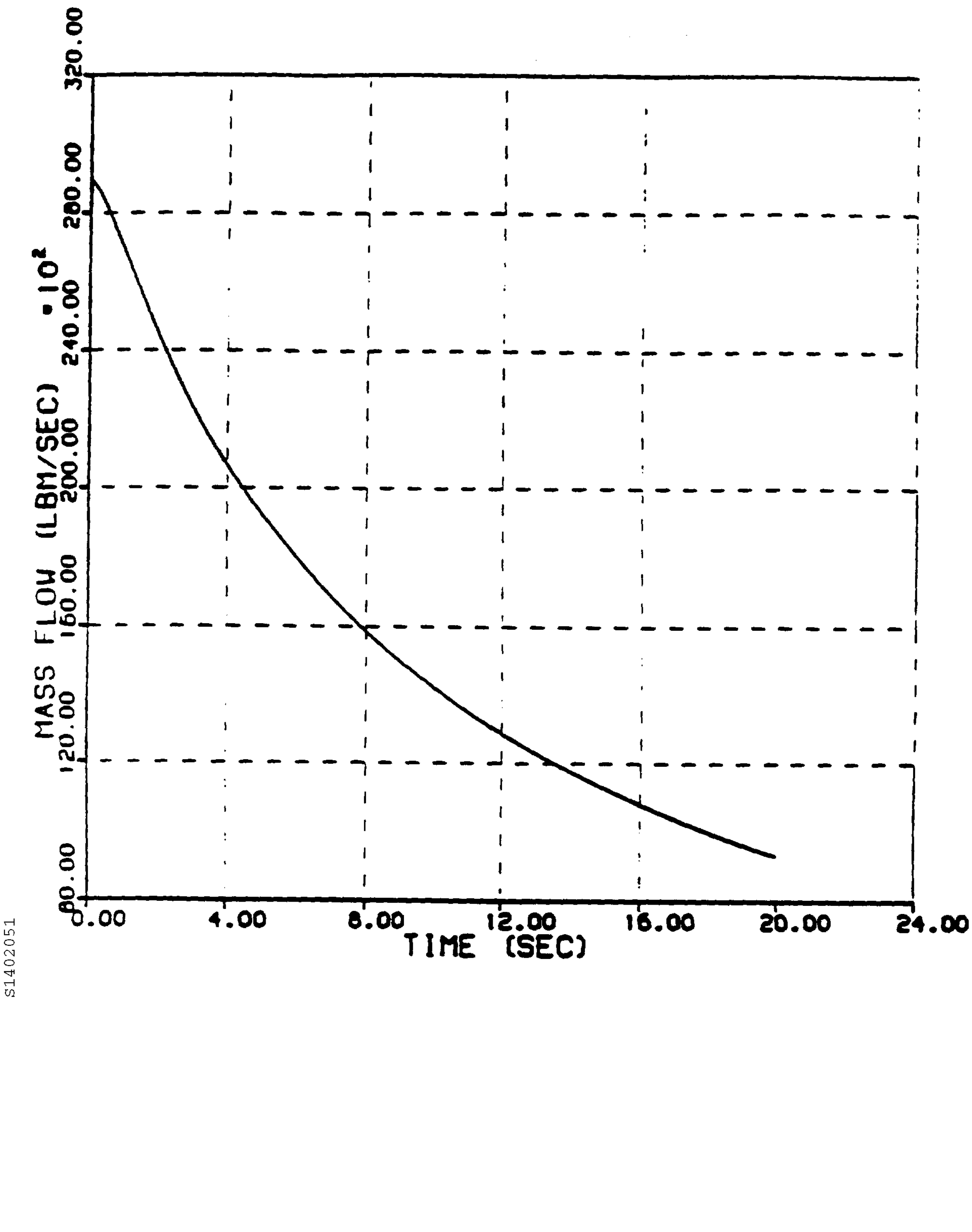


Figure 14.2-41
COMPLETE LOSS OF FLOW - UNDERVOLTAGE CASE
NUCLEAR POWER (% OF 2546 MWt)

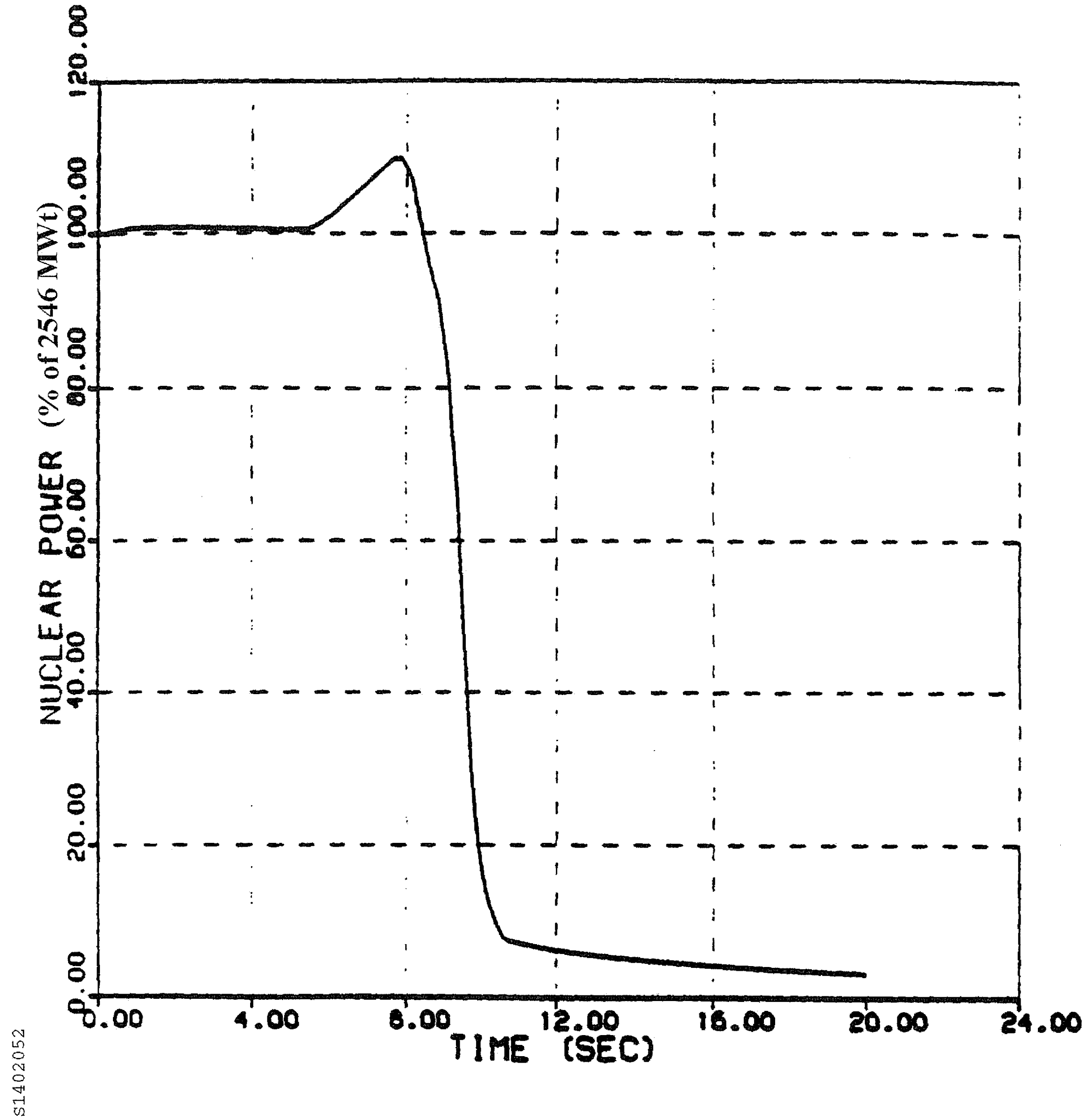
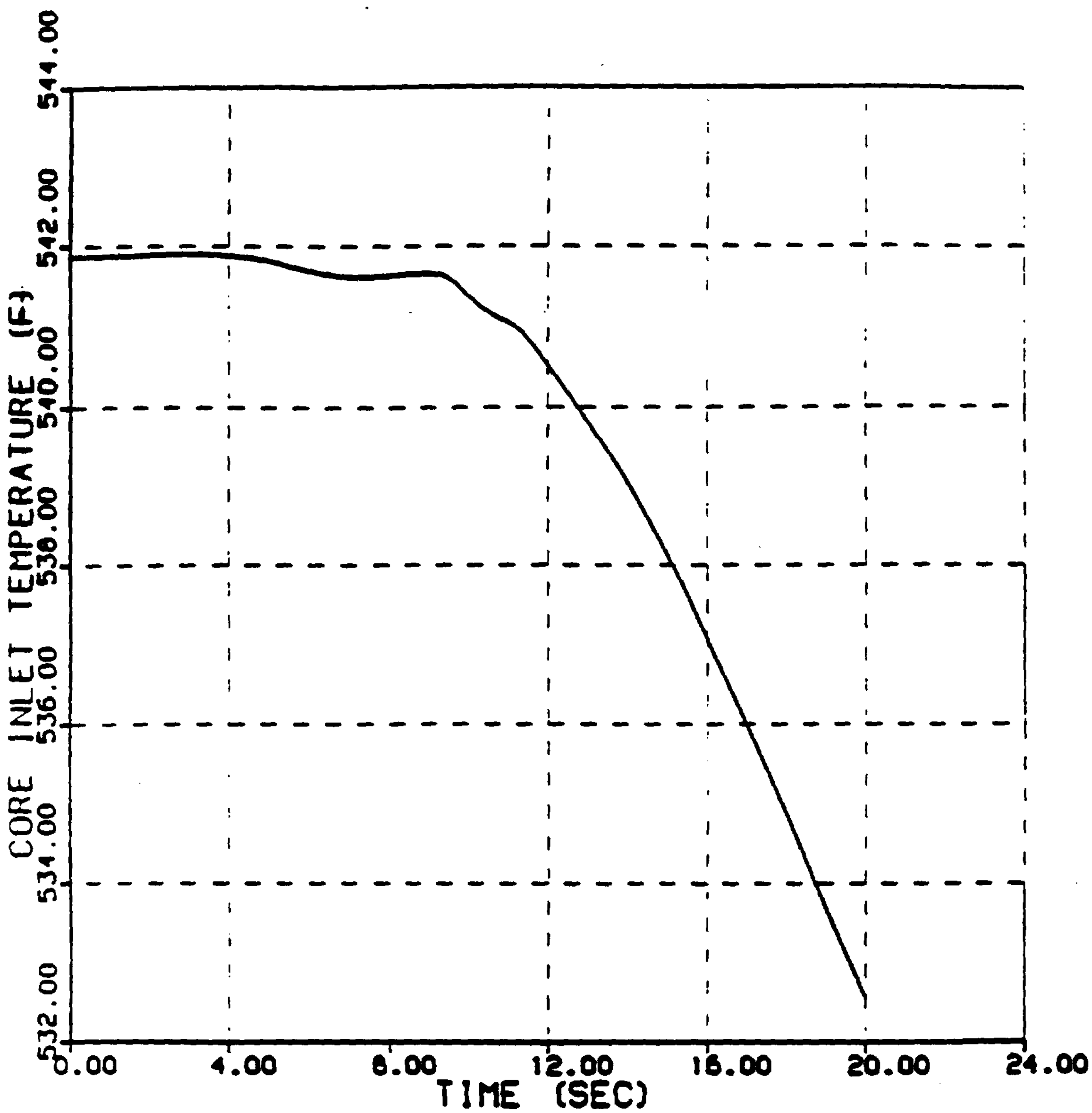


Figure 14.2-42
COMPLETE LOSS OF FLOW - UNDERVOLTAGE CASE CORE INLET TEMPERATURE



S1402053

Figure 14.2-43
COMPLETE LOSS OF FLOW - UNDERVOLTAGE CASE
RCS AVERAGE TEMPERATURE

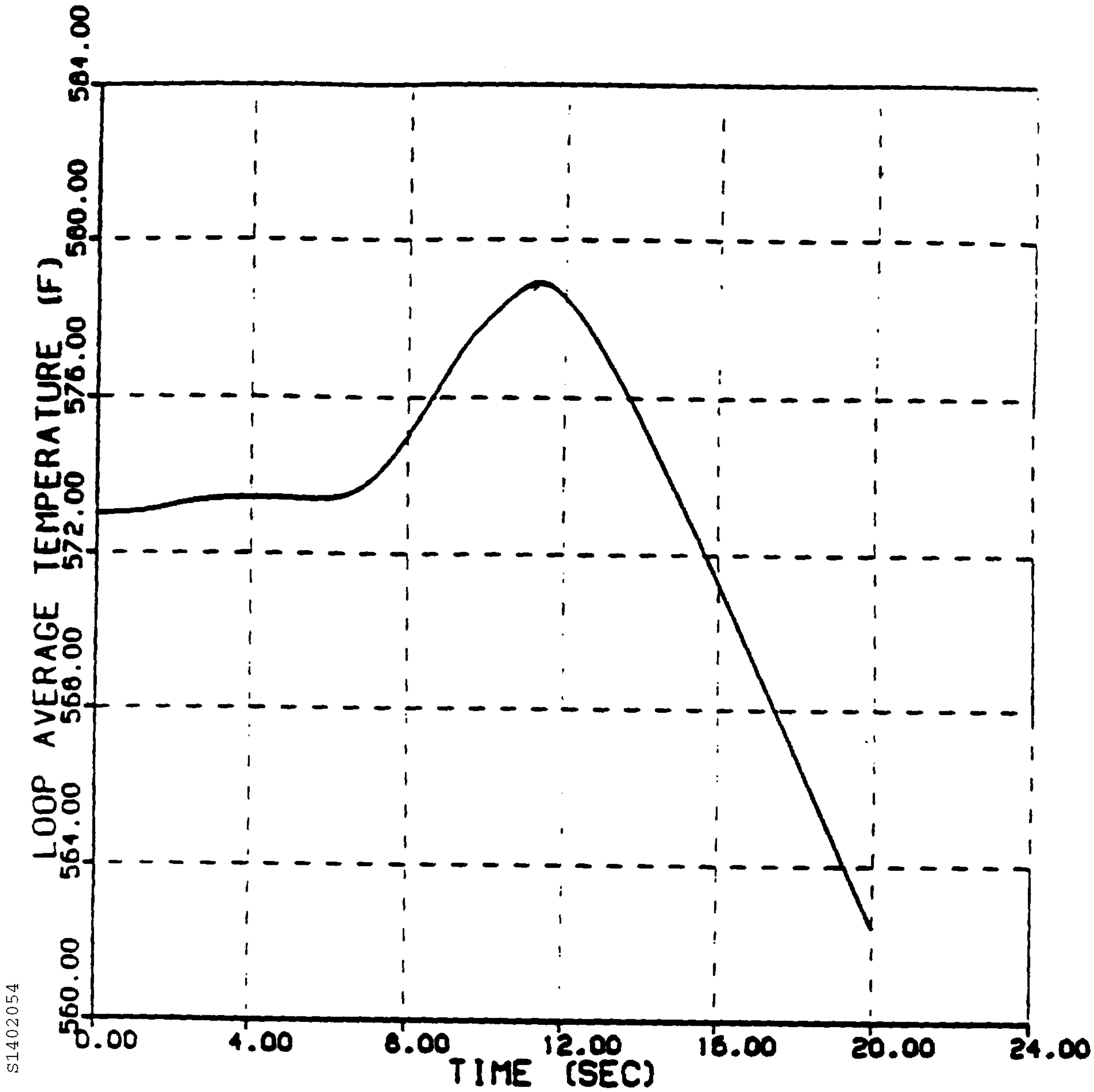


Figure 14.2-44
COMPLETE LOSS OF FLOW - UNDERVOLTAGE CASE PRESSURIZER PRESSURE

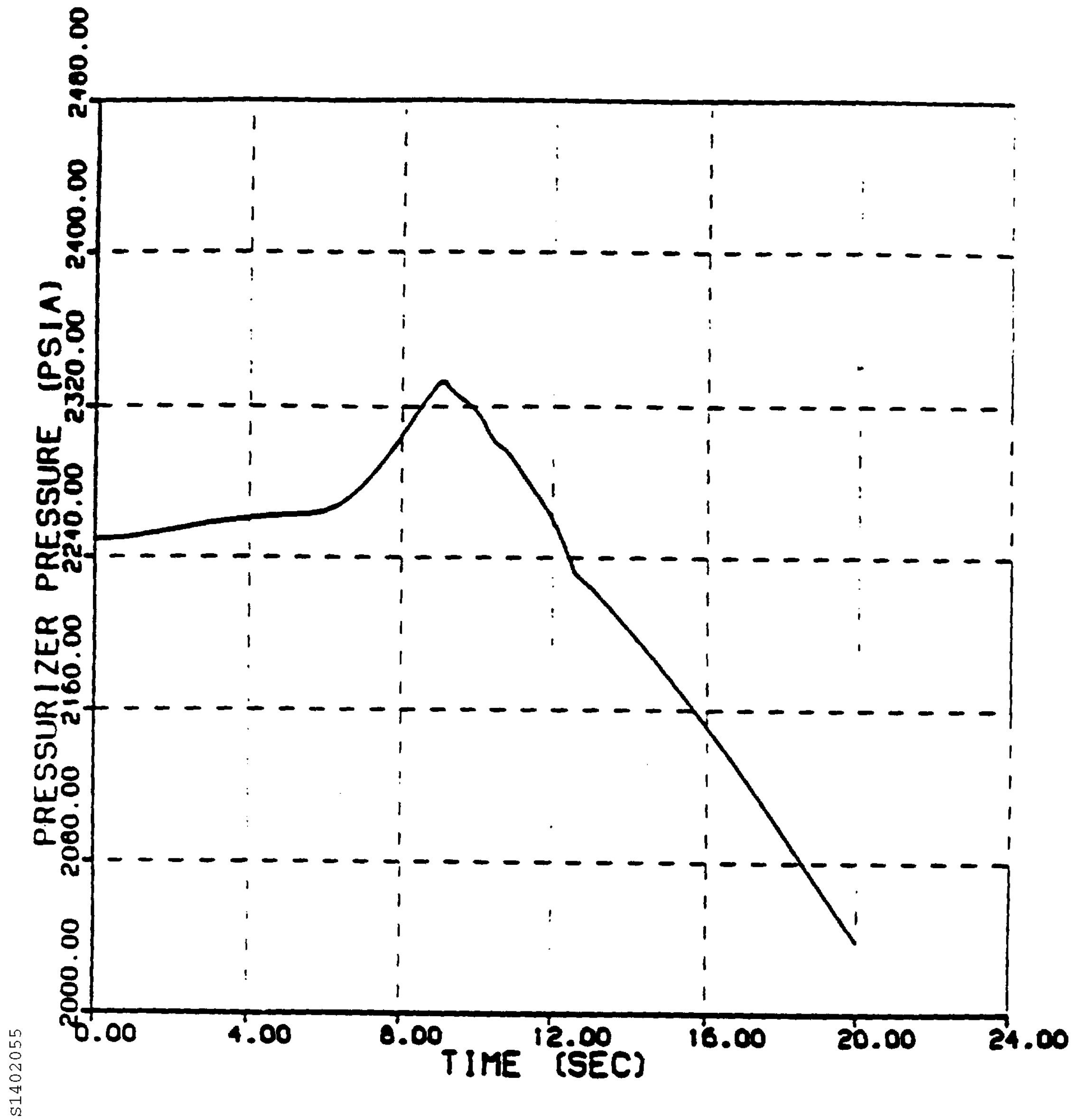


Figure 14.2-45
COMPLETE LOSS OF FLOW - UNDERFREQUENCY CASE
NUCLEAR POWER(% OF 2546 MWt)

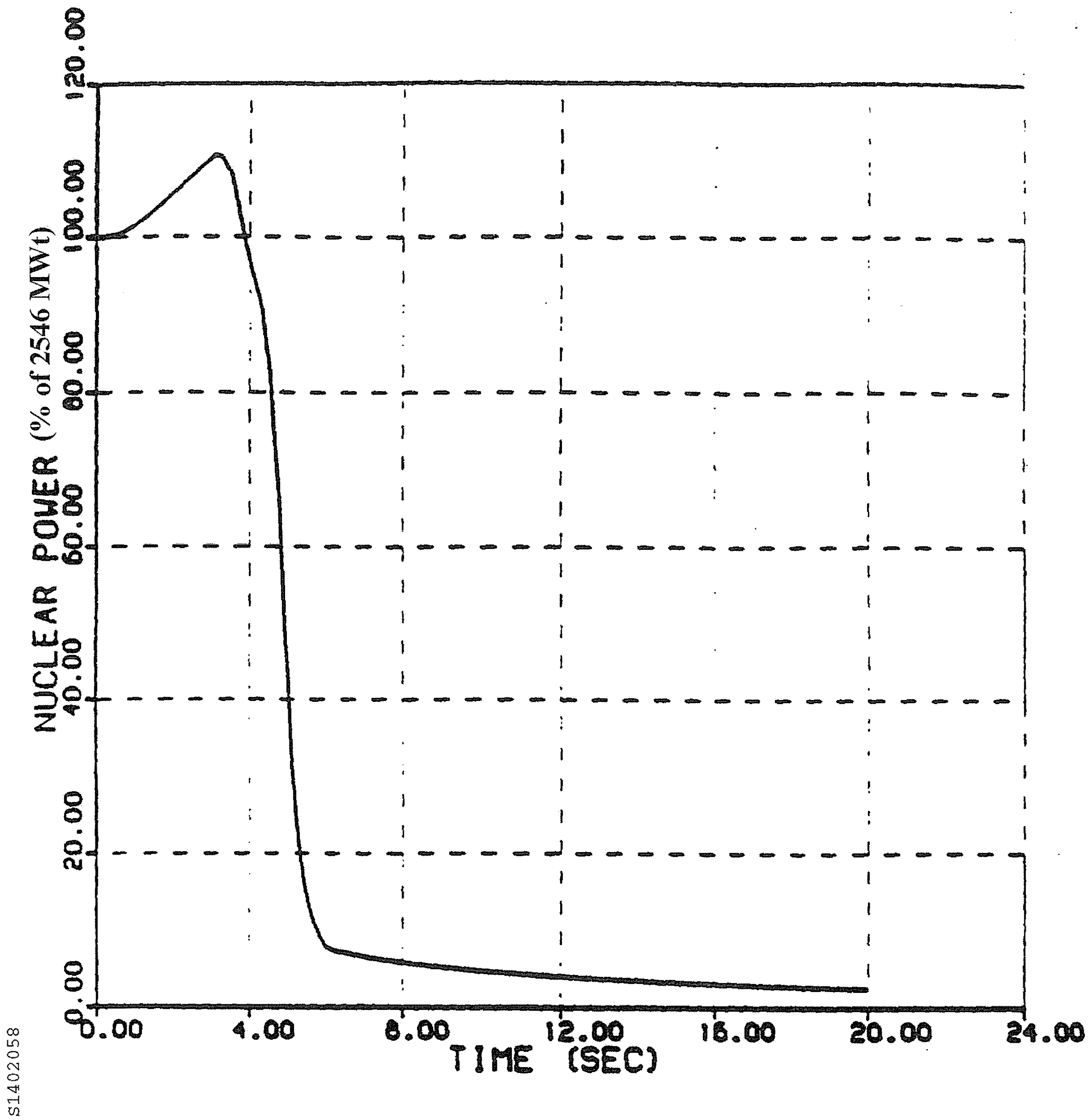


Figure 14.2-46
COMPLETE LOSS OF FLOW - UNDERFREQUENCY CASE
CORE INLET TEMPERATURE

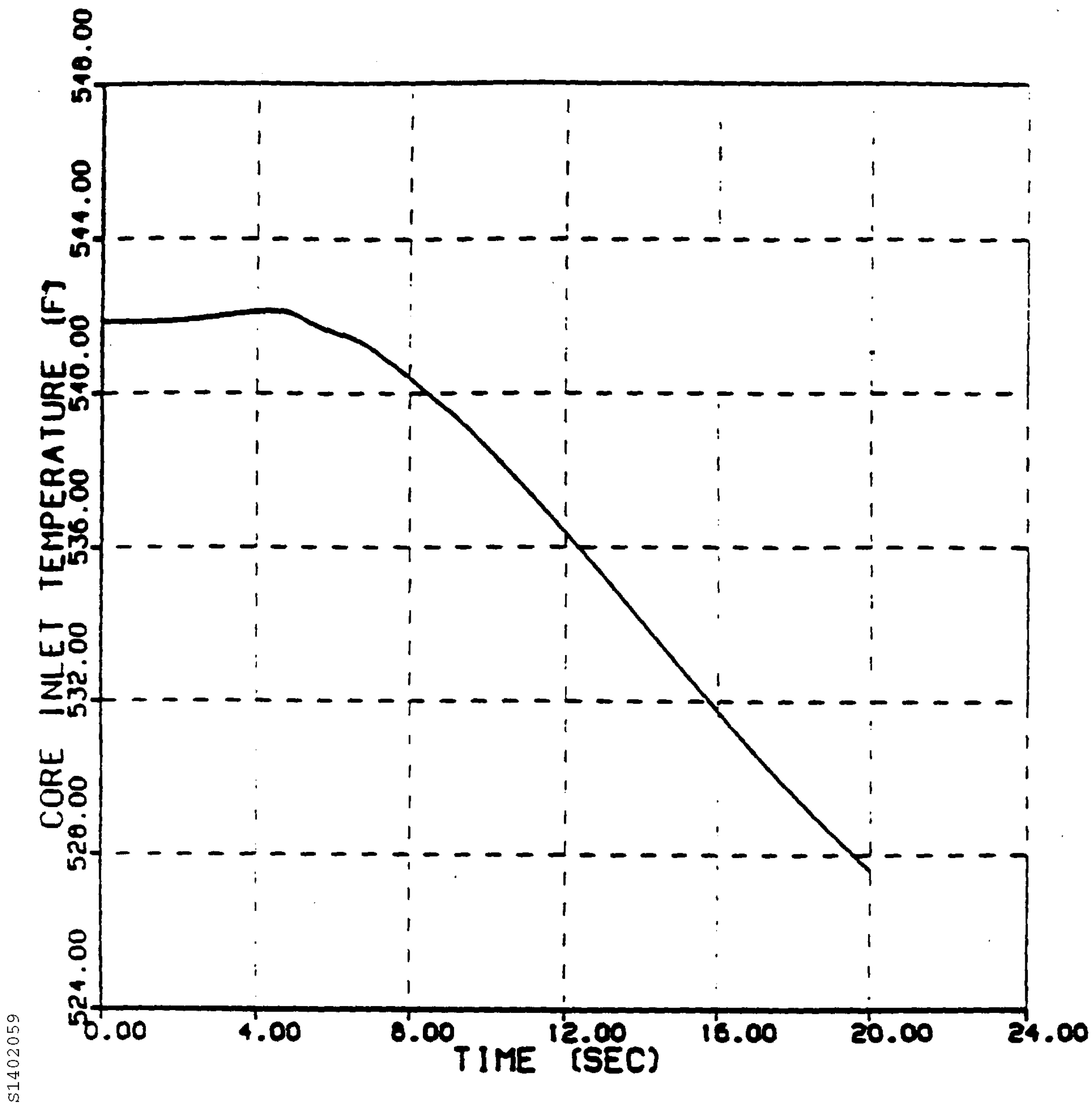
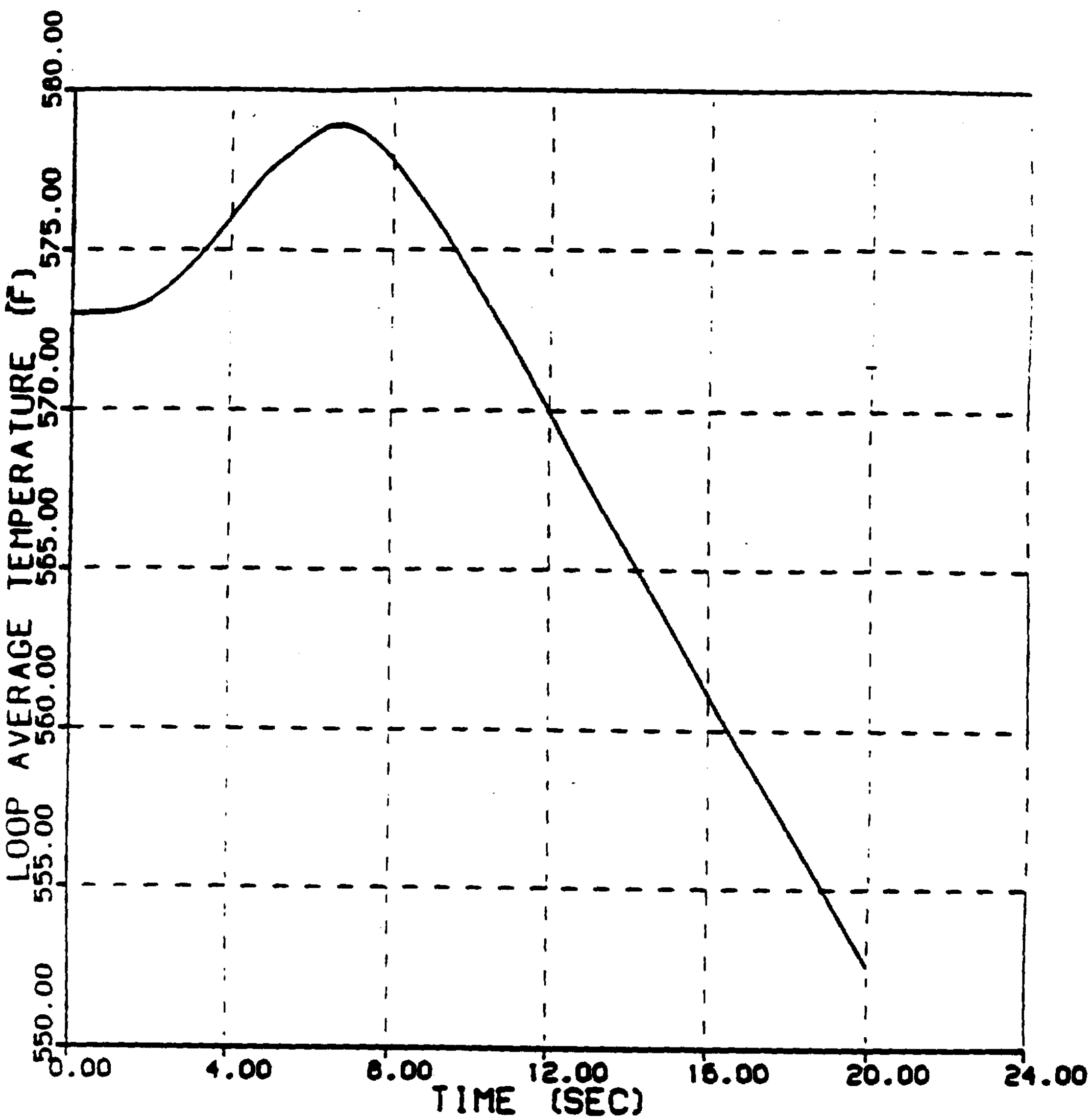


Figure 14.2-47
COMPLETE LOSS OF FLOW - UNDERFREQUENCY CASE
RCS AVERAGE TEMPERATURE



S1402060

Figure 14.2-48
COMPLETE LOSS OF FLOW - UNDERFREQUENCY CASE PRESSURIZER PRESSURE

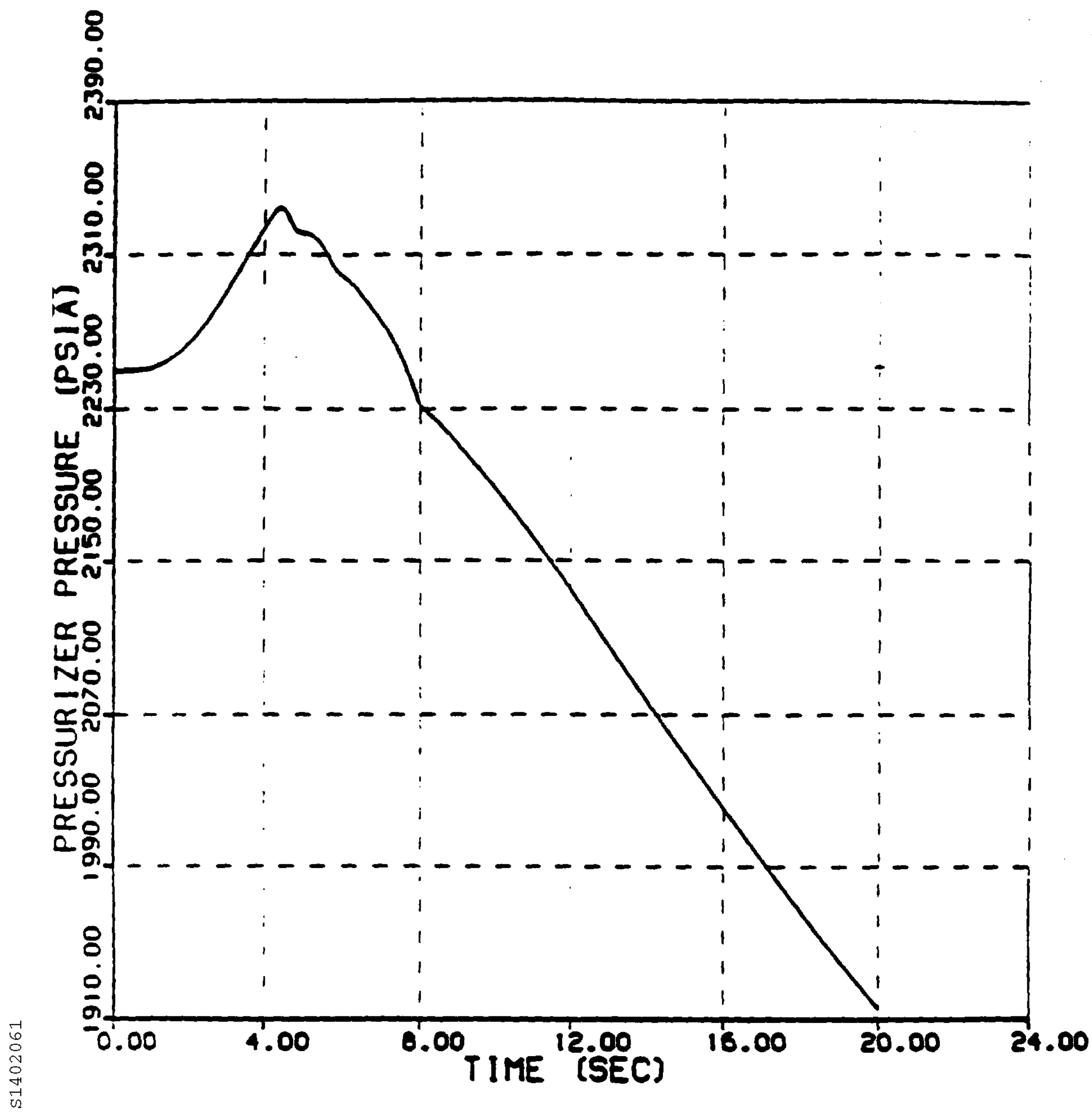


Figure 14.2-49
LOCKED ROTOR - DNBR ANALYSIS CASE CORE INLET MASS FLOW RATE

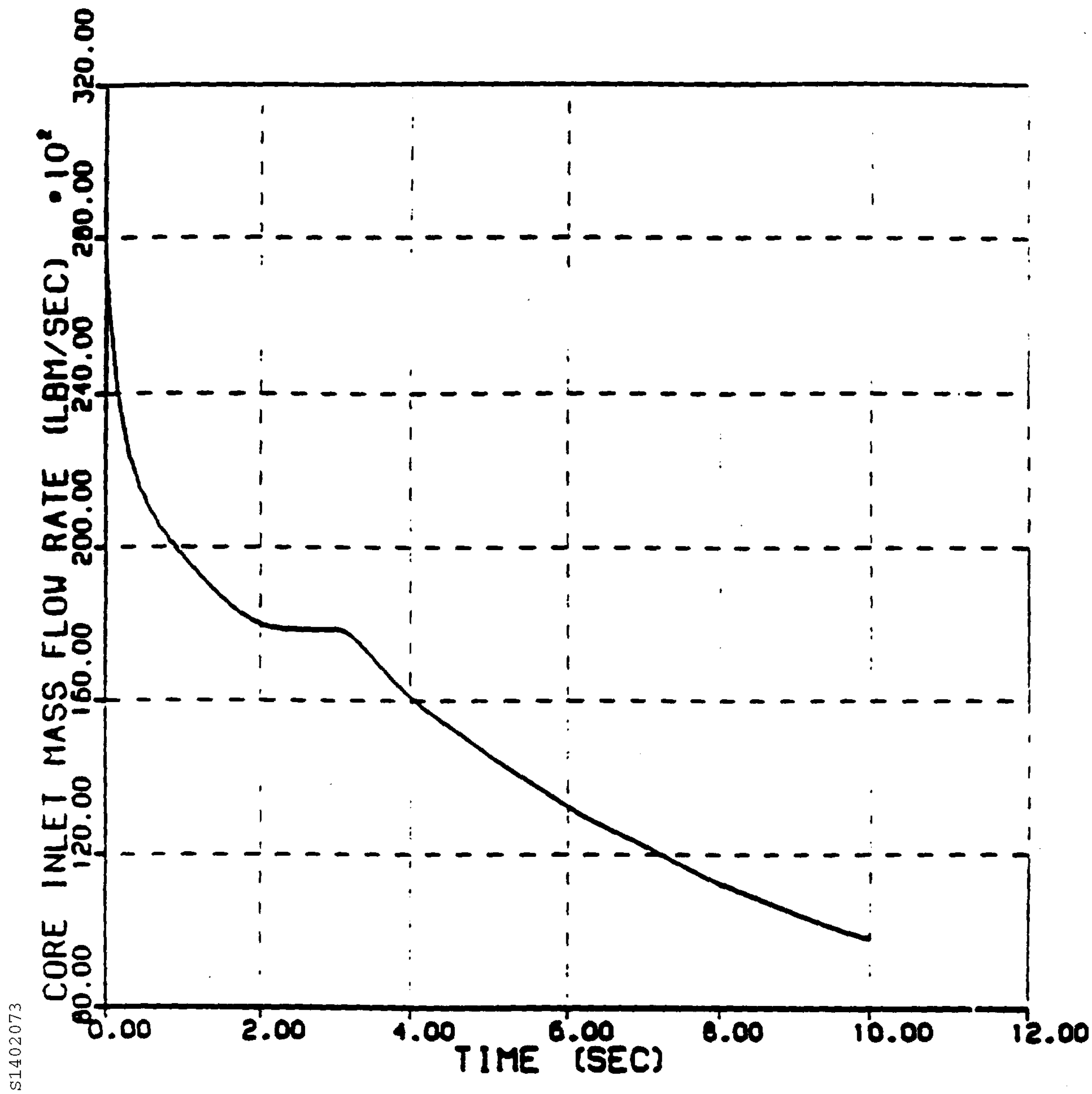


Figure 14.2-50
LOCKED ROTOR - DNBR ANALYSIS CASE CORE HEAT FLUX

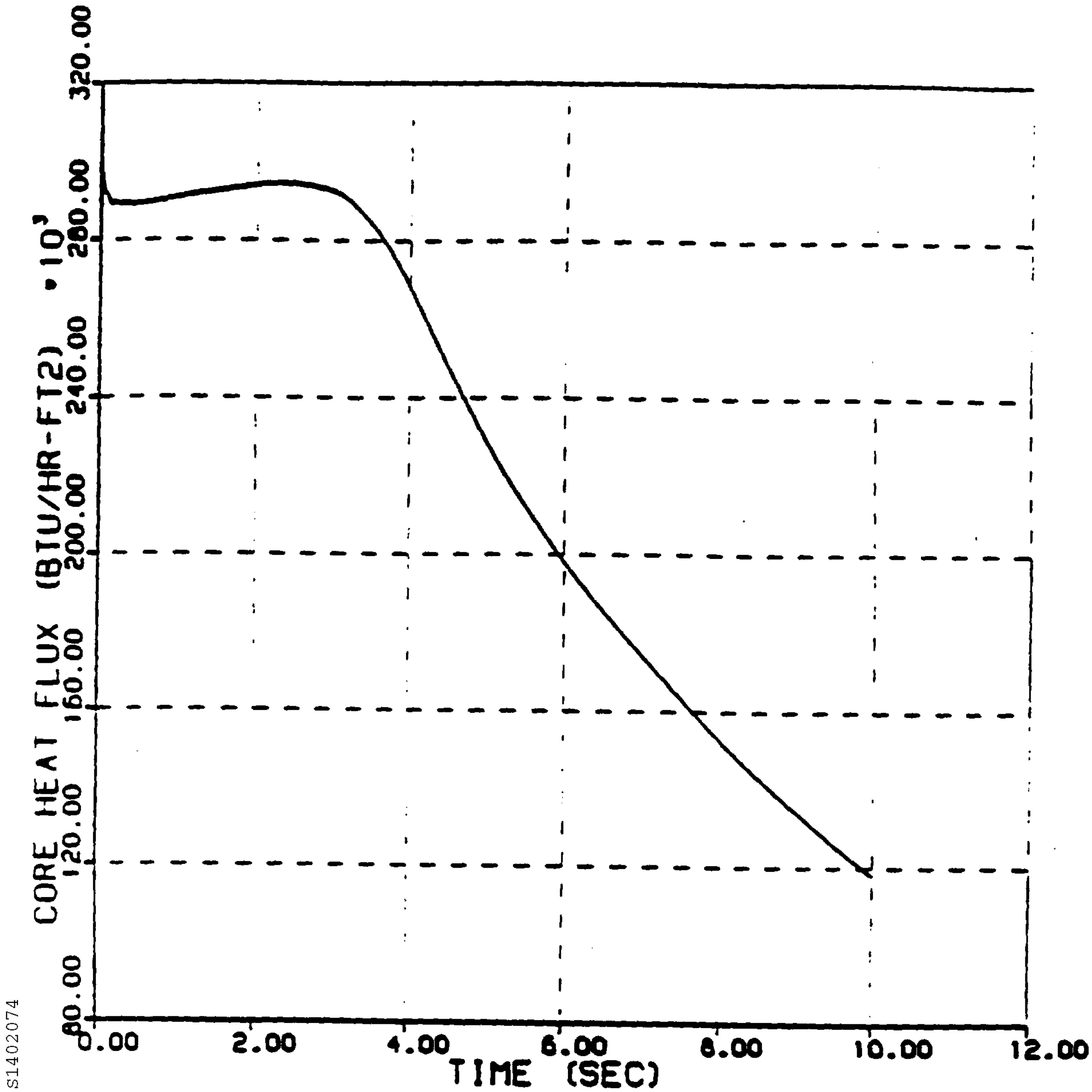


Figure 14.2-51
LOCKED ROTOR - DNBR ANALYSIS CASE CORE INLET TEMPERATURE

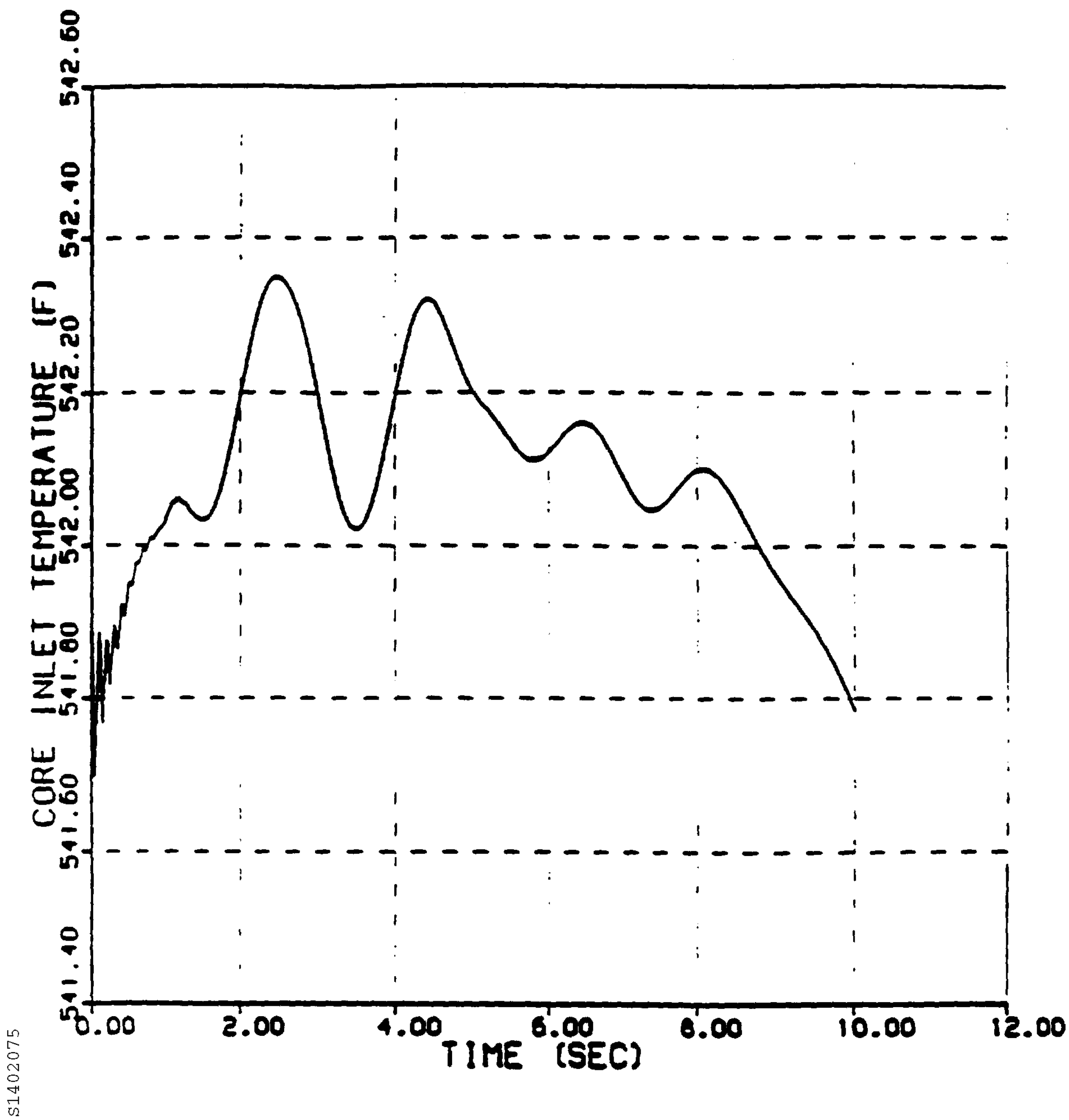
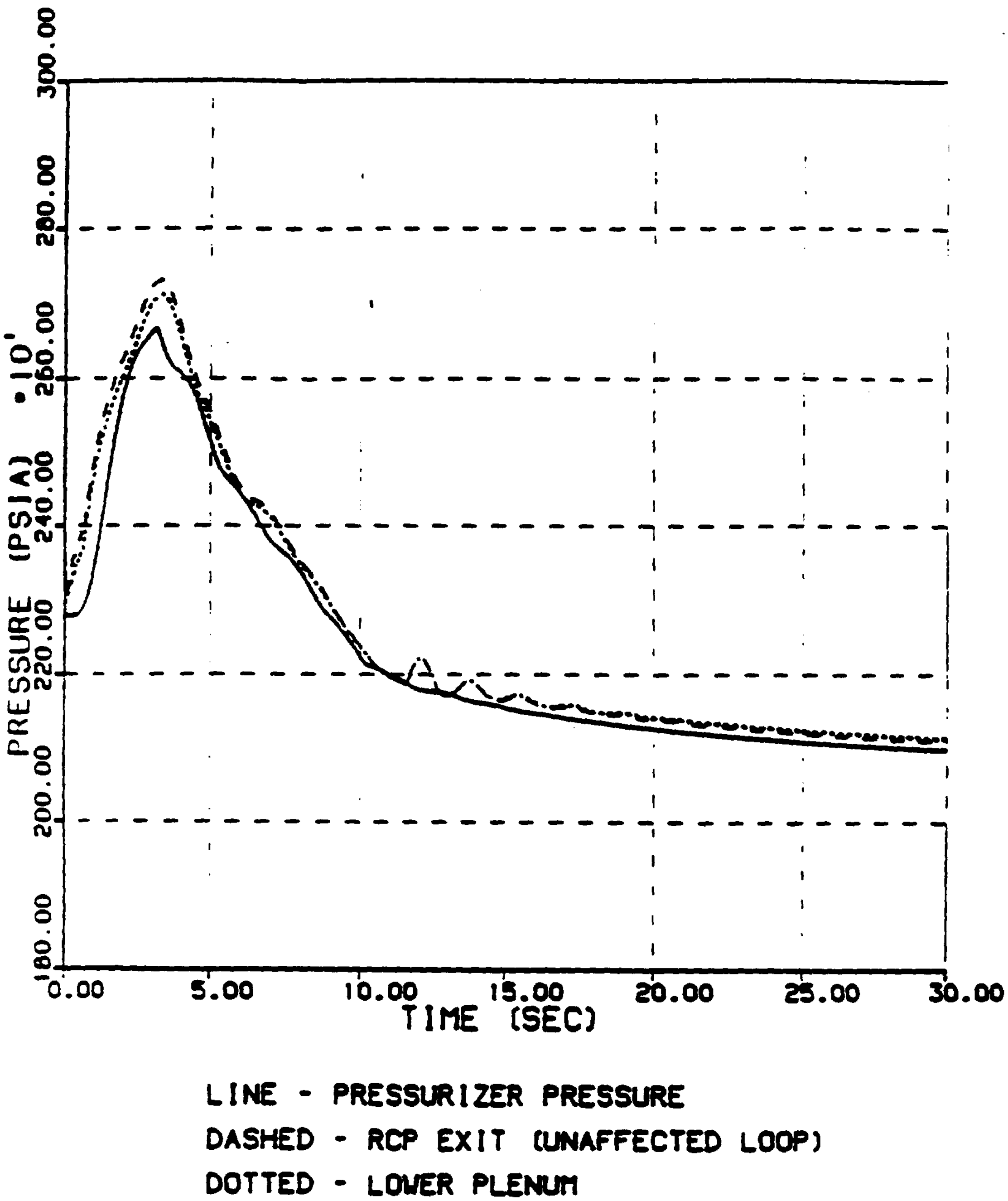


Figure 14.2-52
LOCKED ROTOR - RCS OVERPRESSURE CASE
RCS PRESSURE - PRESSURIZER, RCP EXIT, LOWER PLENUM



S1402076

Figure 14.2-53
LOCKED ROTOR - RCS OVERPRESSURE CASE STEAM GENERATOR PRESSURE

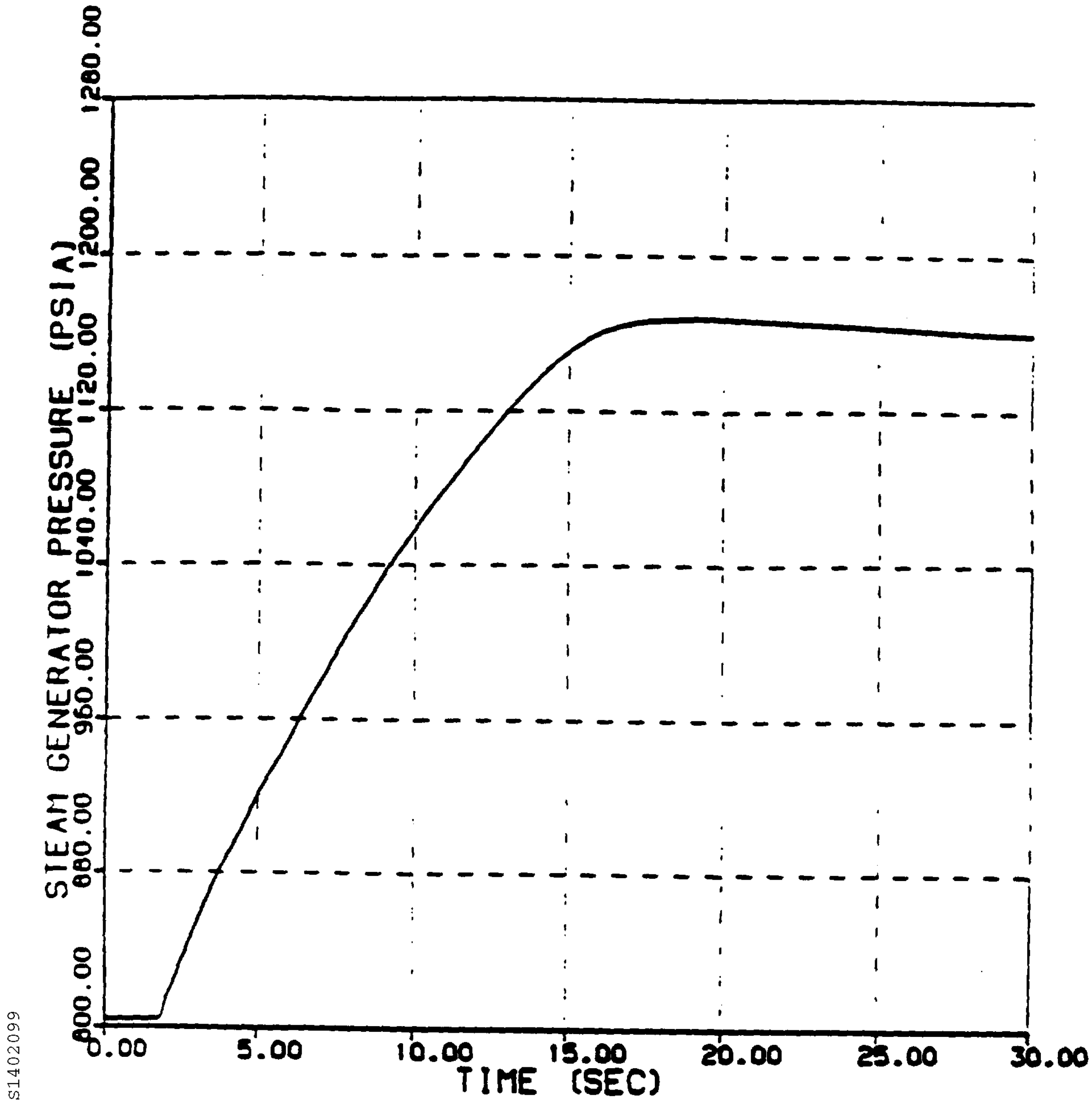


Figure 14.2-54
LOSS OF EXTERNAL LOAD - BOC WITH PRESSURIZER RELIEF & SPRAY
NUCLEAR POWER (% OF 2546 MWt)

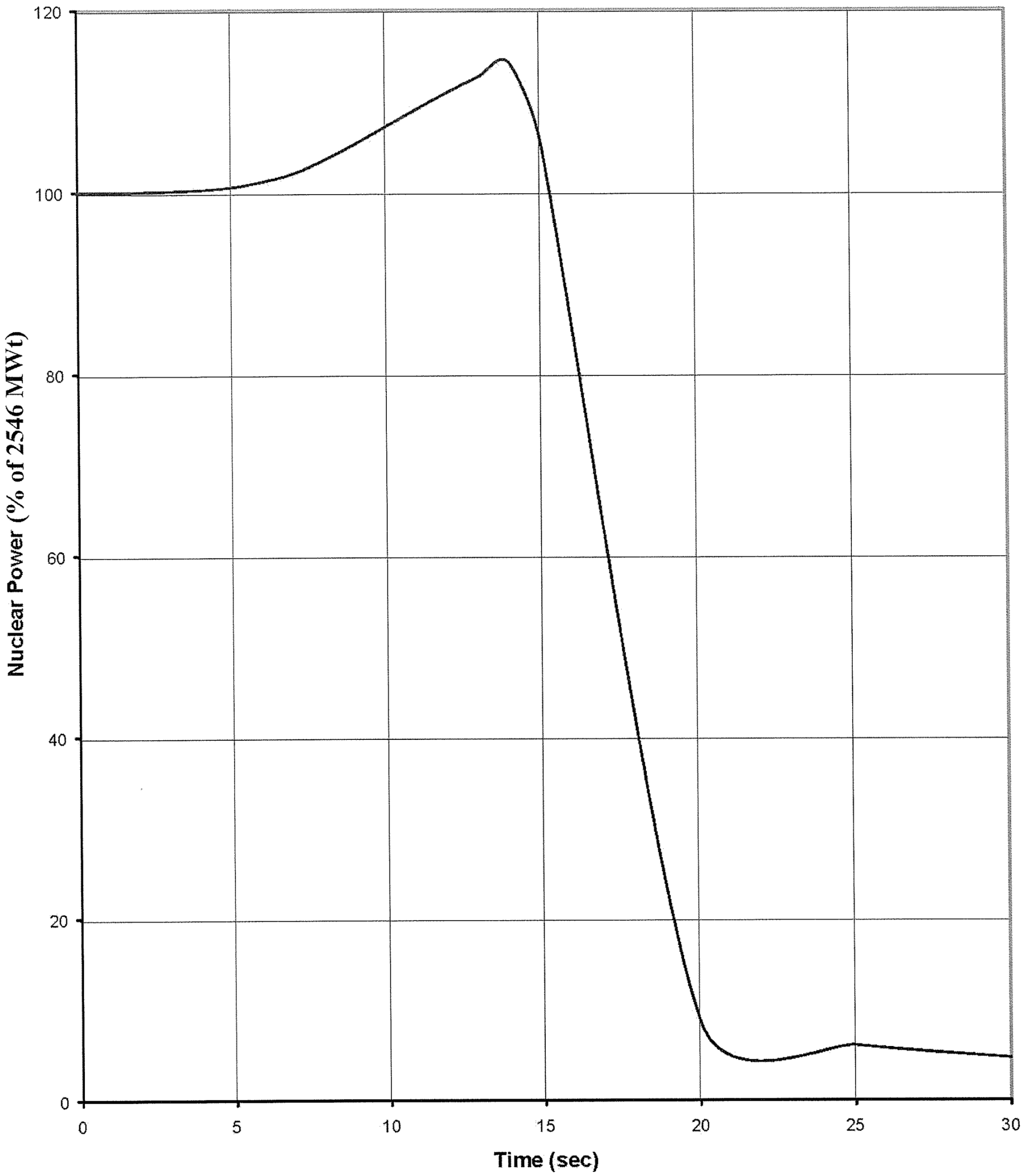


Figure 14.2-55
LOSS OF EXTERNAL LOAD - BOC WITH PRESSURIZER RELIEF & SPRAY
CORE INLET TEMPERATURE

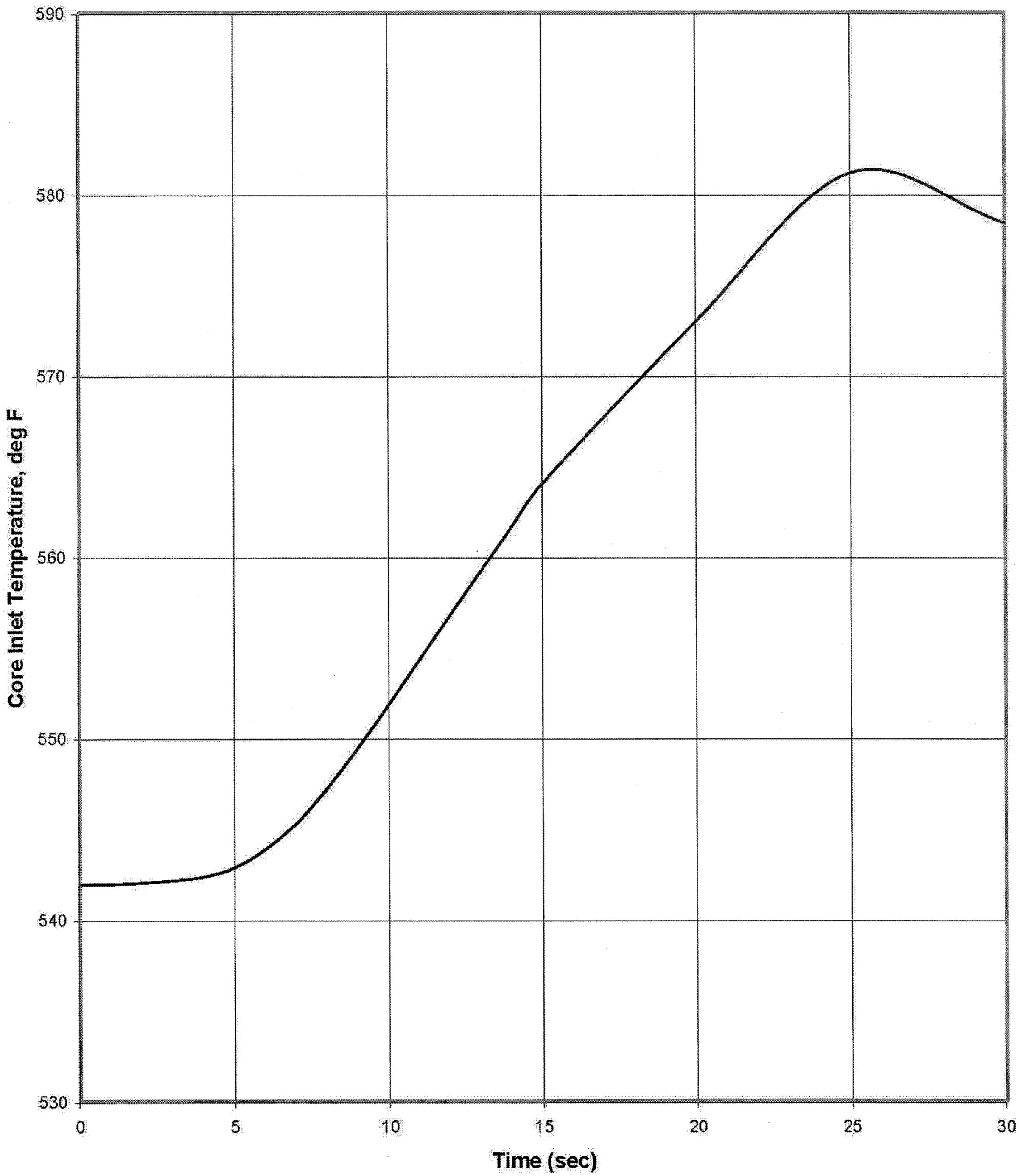


Figure 14.2-56
LOSS OF EXTERNAL LOAD - BOC WITH PRESSURIZER RELIEF & SPRAY
PRESSURIZER LIQUID VOLUME

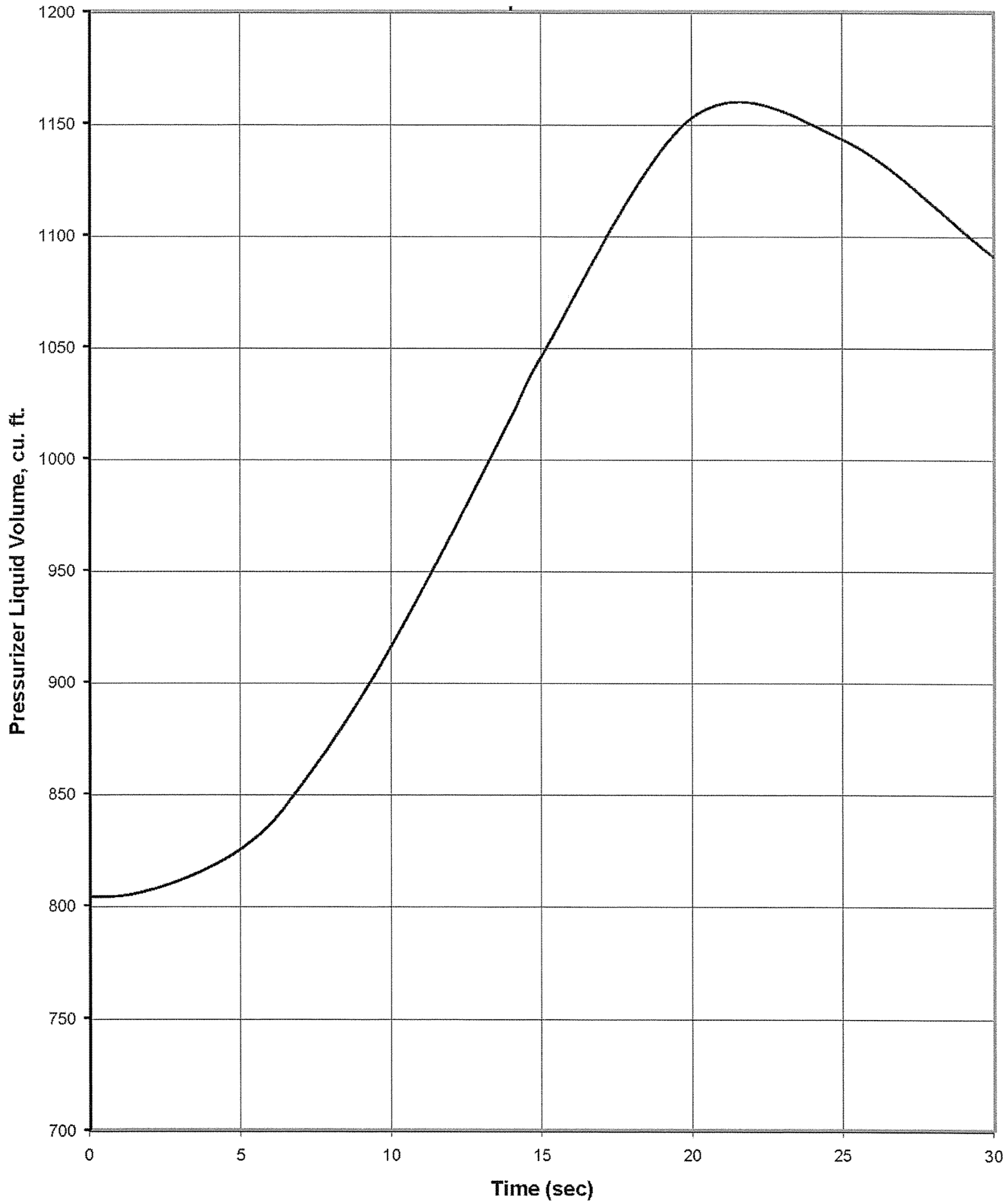


Figure 14.2-57
LOSS OF EXTERNAL LOAD - BOC WITH PRESSURIZER RELIEF & SPRAY
RCS COLD LEG PRESSURE

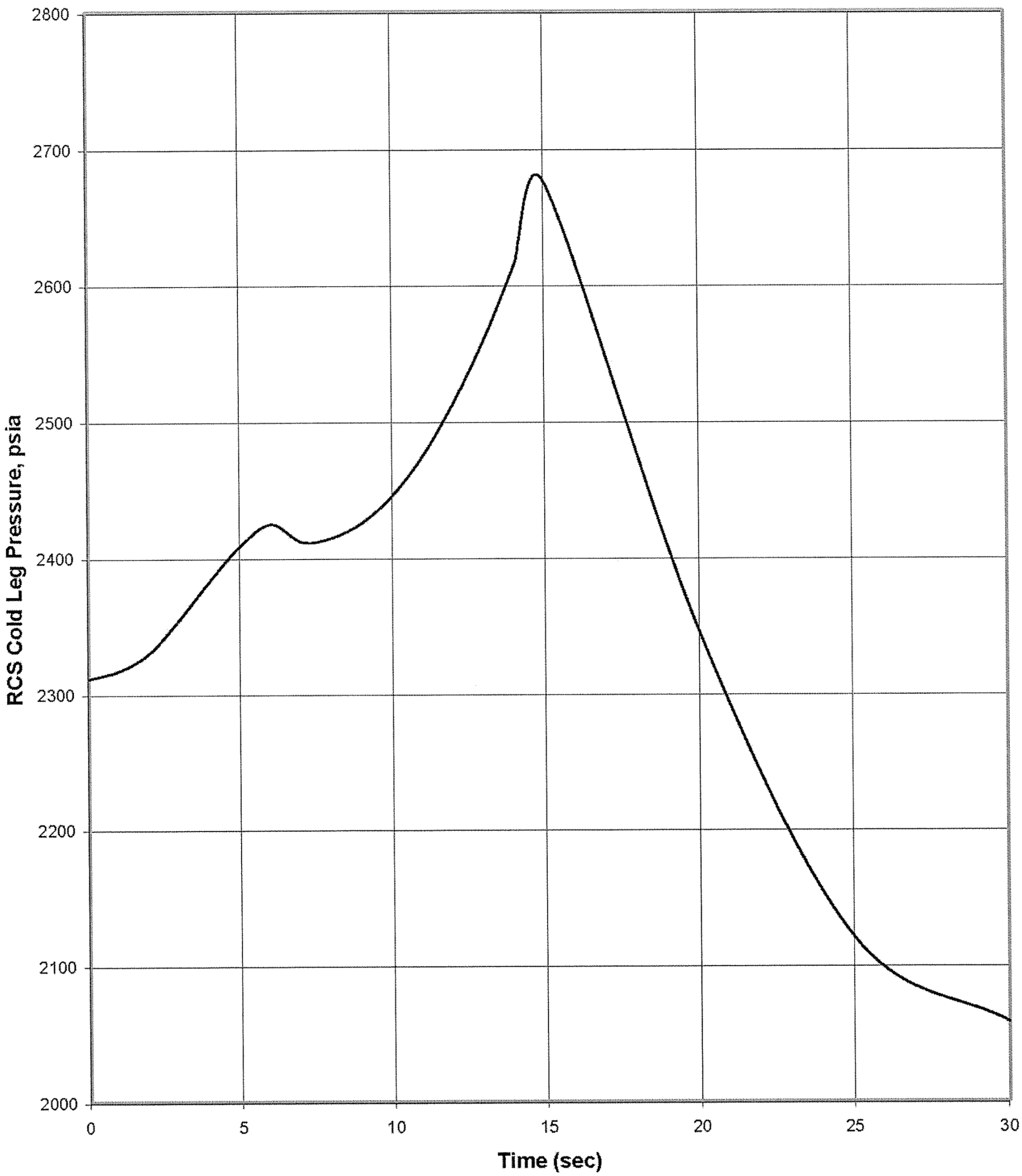


Figure 14.2-58
LOSS OF EXTERNAL LOAD - BOC WITH PRESSURIZER RELIEF & SPRAY
STEAM GENERATOR PRESSURE

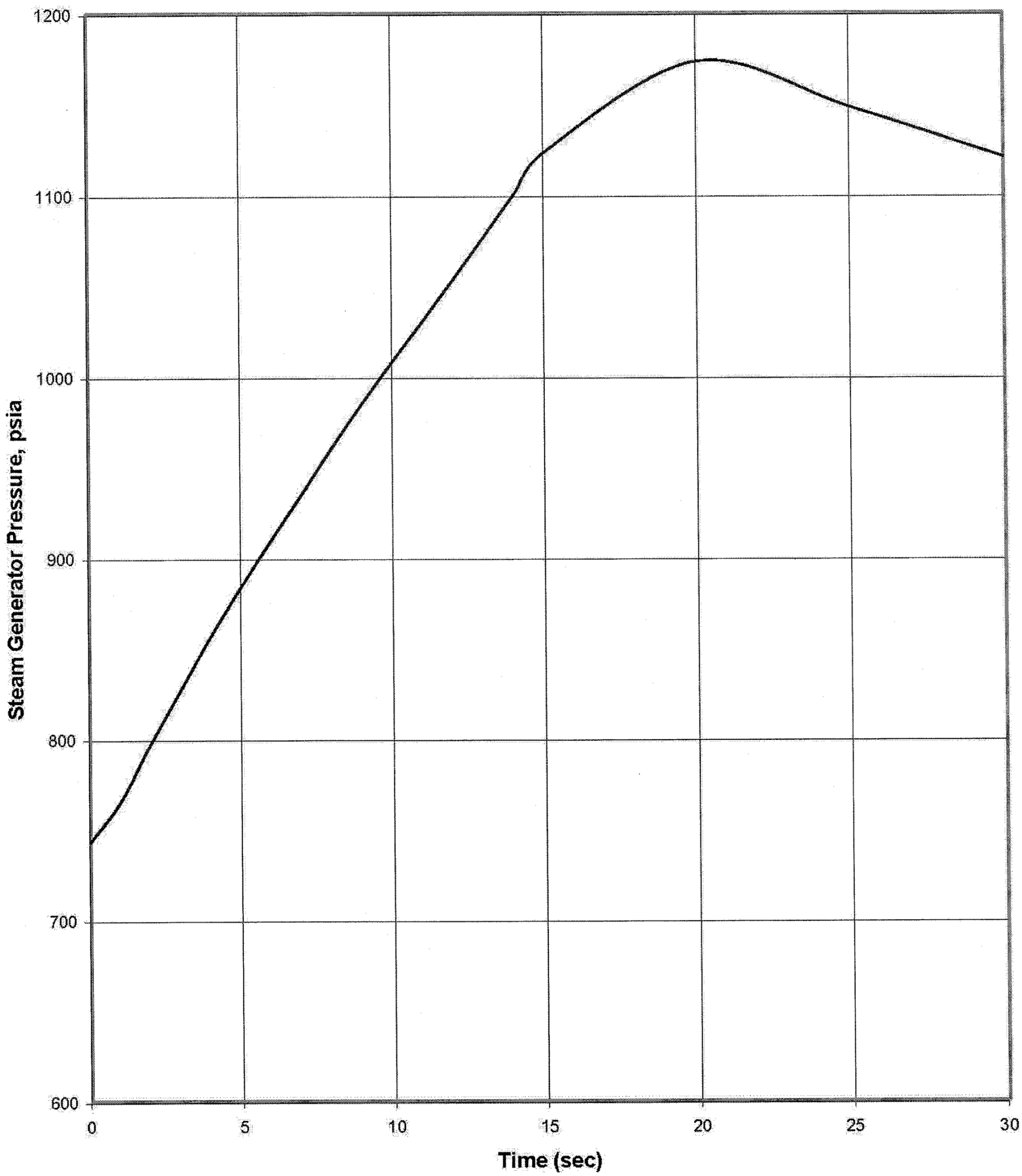


Figure 14.2-59
LOSS OF EXTERNAL LOAD - BOC WITHOUT PRESSURIZER RELIEF & SPRAY
NUCLEAR POWER (% OF 2546 MWt)

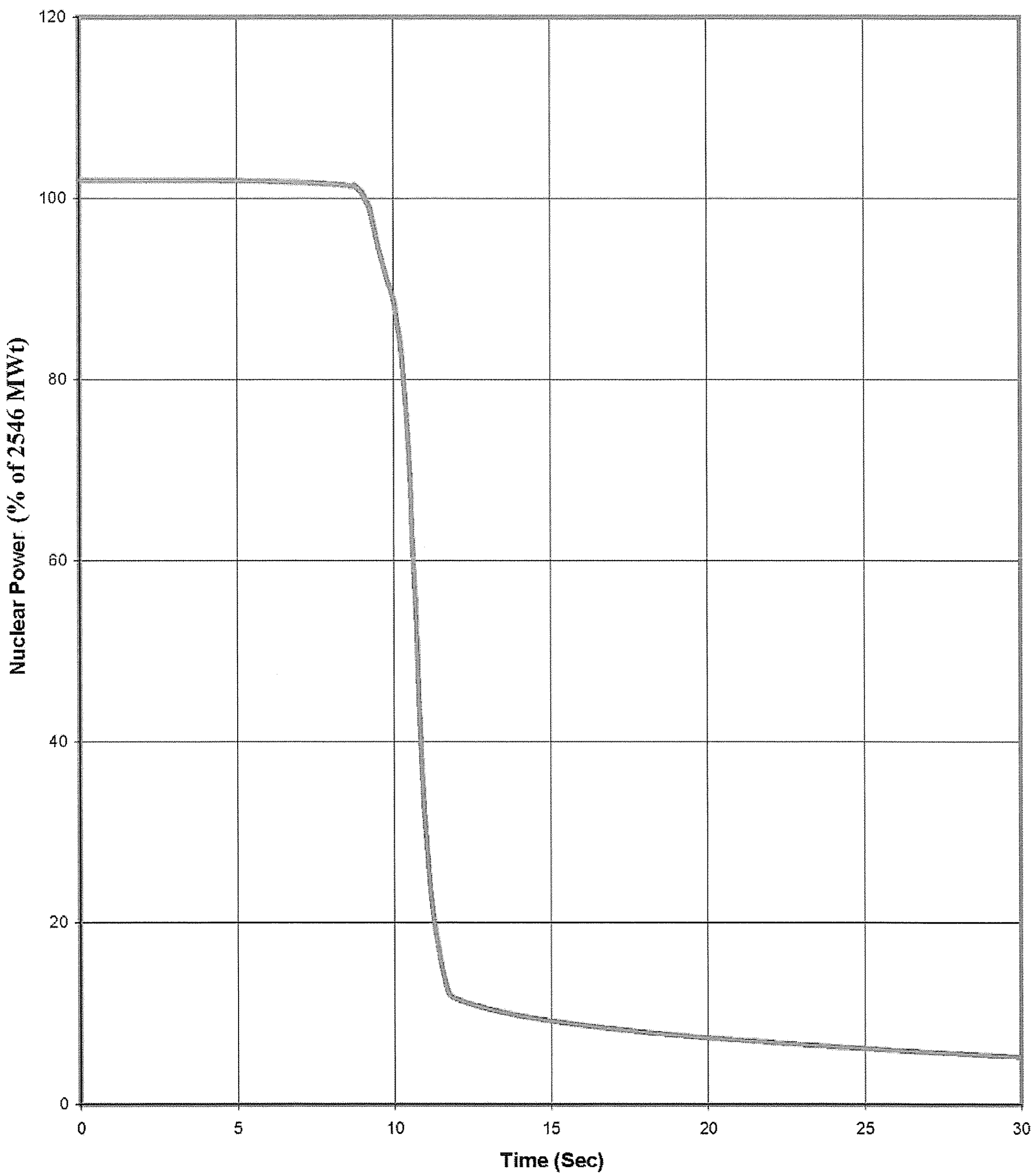


Figure 14.2-60
LOSS OF EXTERNAL LOAD - BOC WITHOUT PRESSURIZER RELIEF & SPRAY
CORE INLET TEMPERATURE

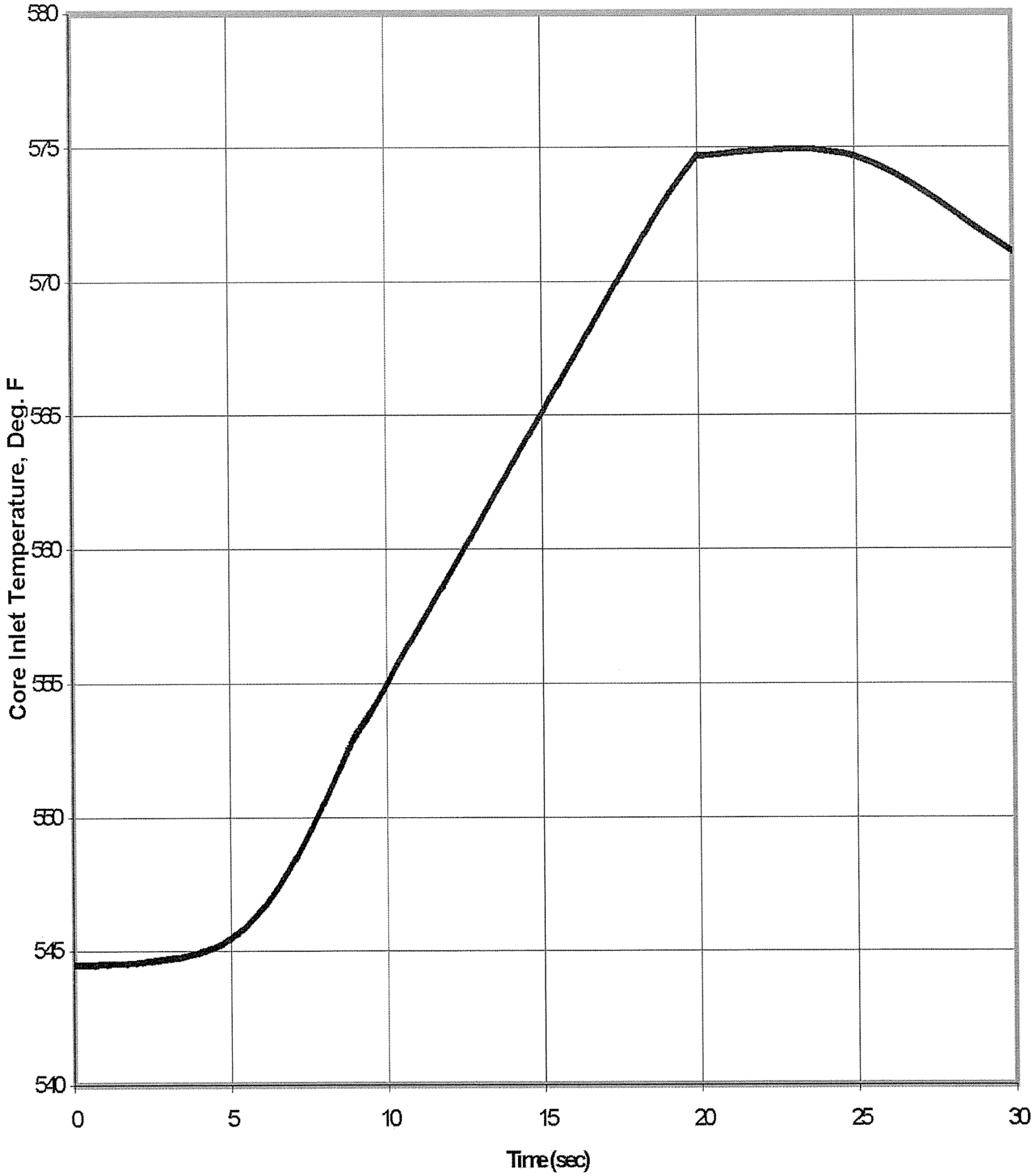


Figure 14.2-61
LOSS OF EXTERNAL LOAD - BOC WITHOUT PRESSURIZER RELIEF & SPRAY
PRESSURIZER LIQUID VOLUME

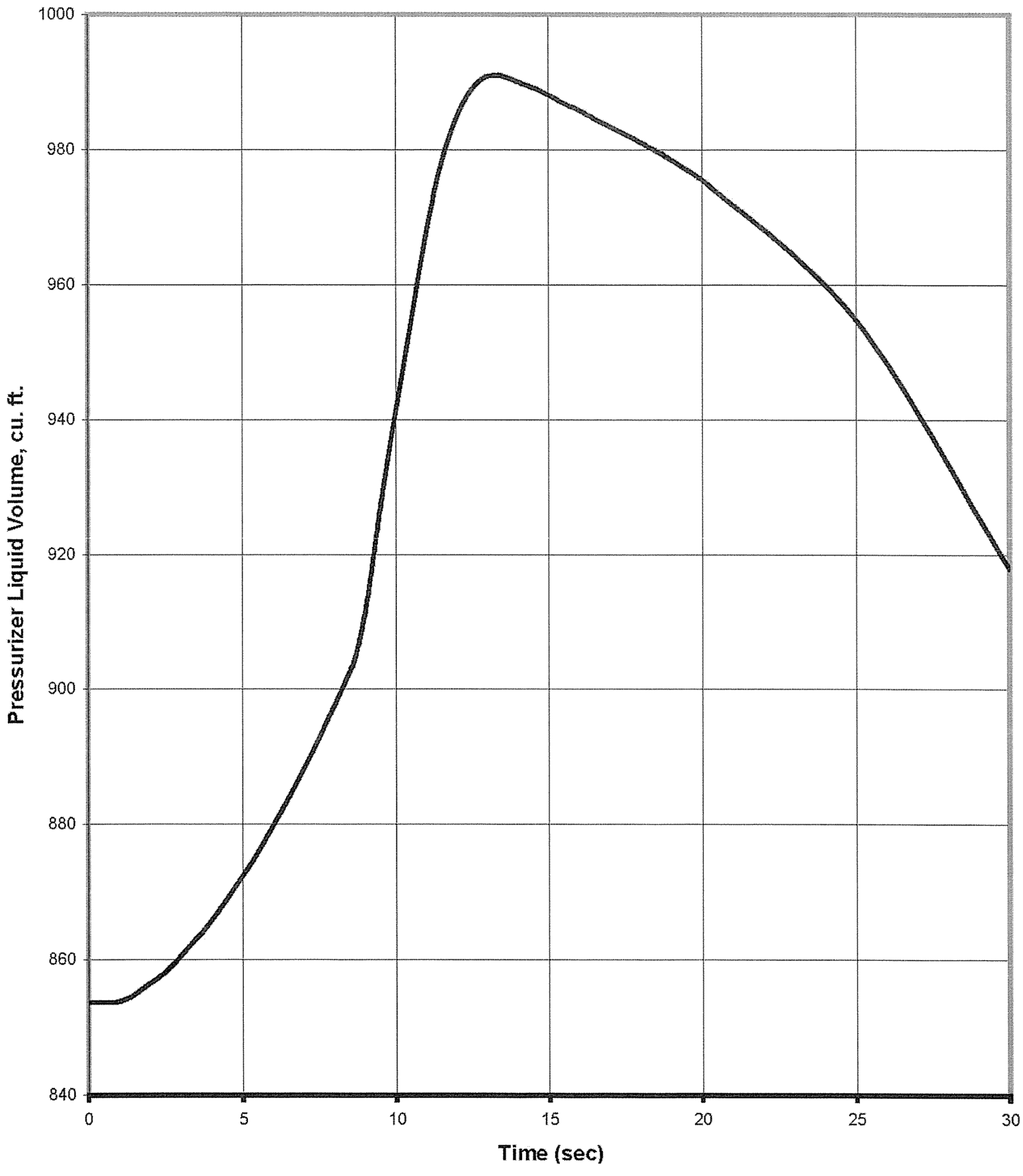


Figure 14.2-62
LOSS OF EXTERNAL LOAD - BOC WITHOUT PRESSURIZER RELIEF & SPRAY
RCS COLD LEG PRESSURE

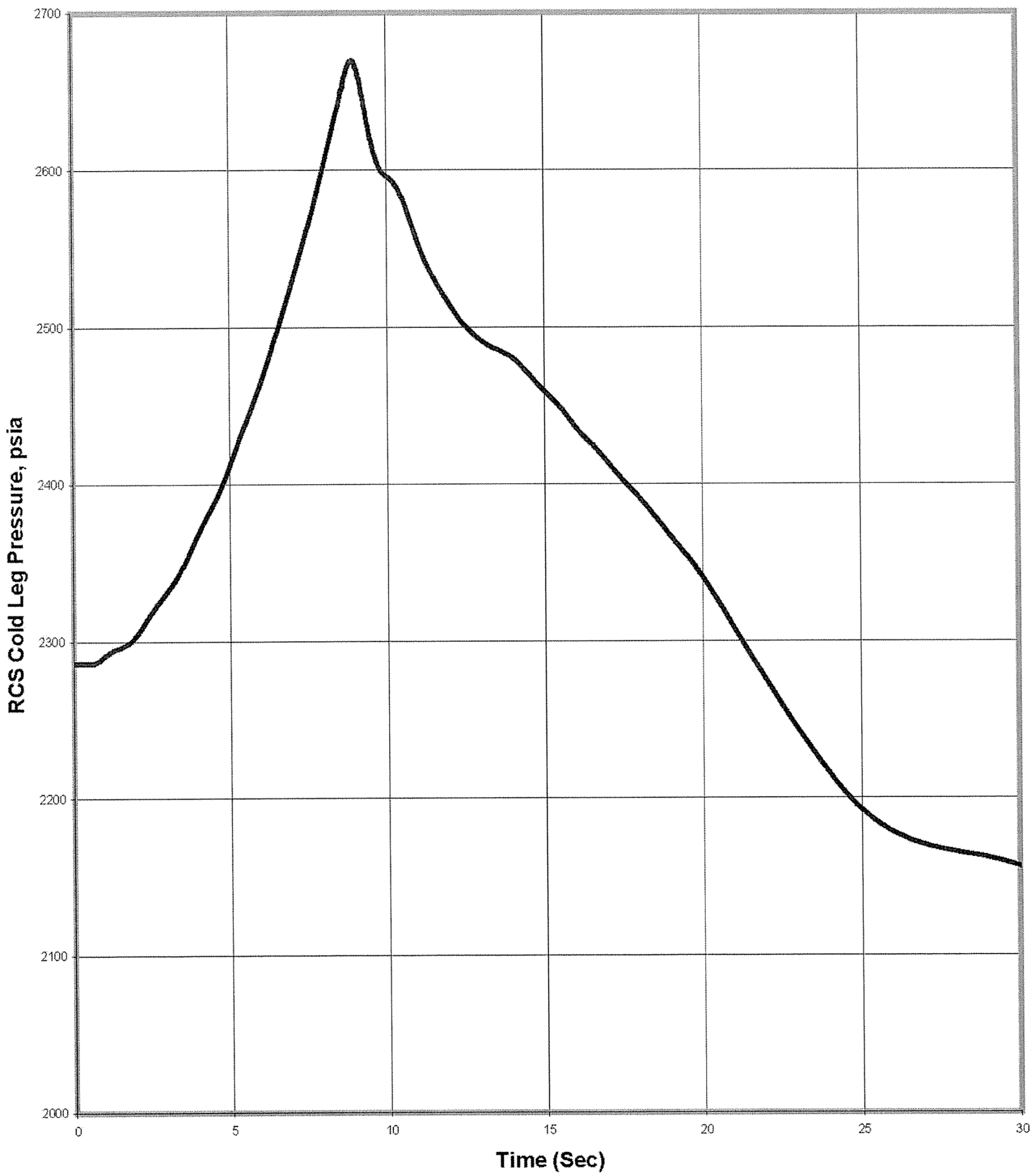


Figure 14.2-63
LOSS OF EXTERNAL LOAD - BOC WITHOUT PRESSURIZER RELIEF & SPRAY
STEAM GENERATOR PRESSURE

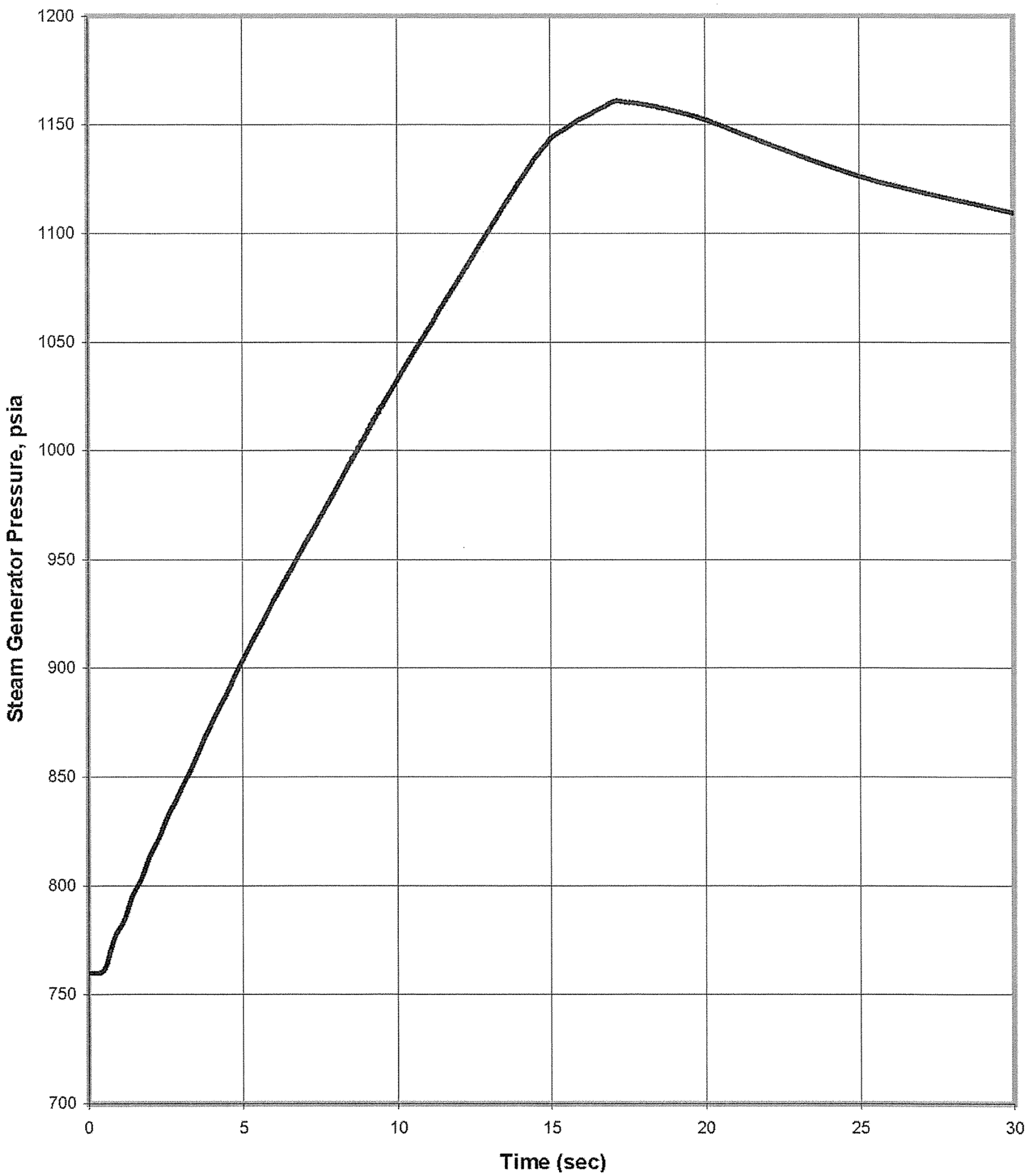


Figure 14.2-64
LOSS OF NORMAL FEEDWATER; PRESSURIZER PRESSURE
(OFFSITE POWER NOT AVAILABLE)

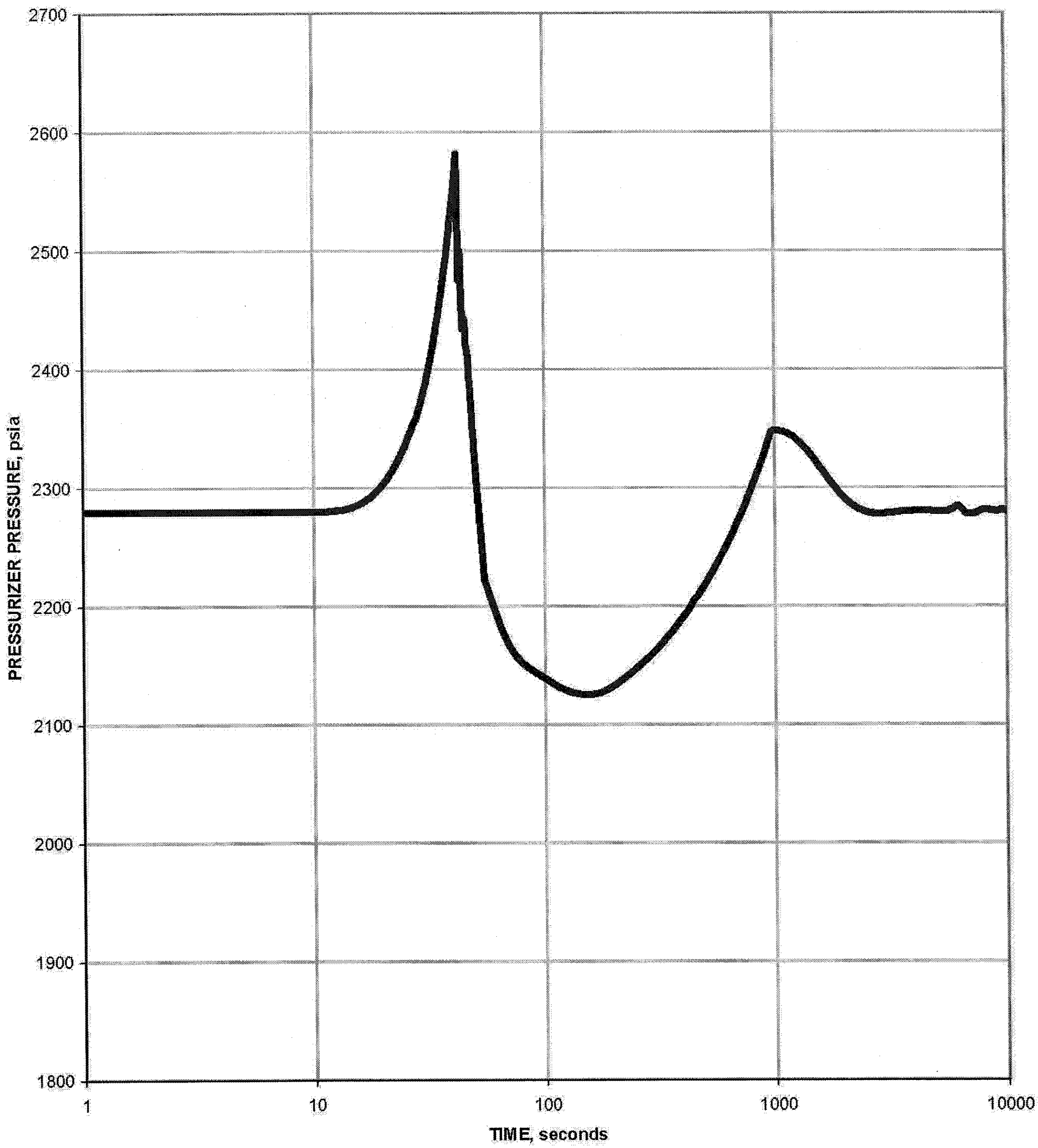


Figure 14.2-65
LOSS OF NORMAL FEEDWATER; PRESSURIZER WATER VOLUME
(OFFSITE POWER NOT AVAILABLE)

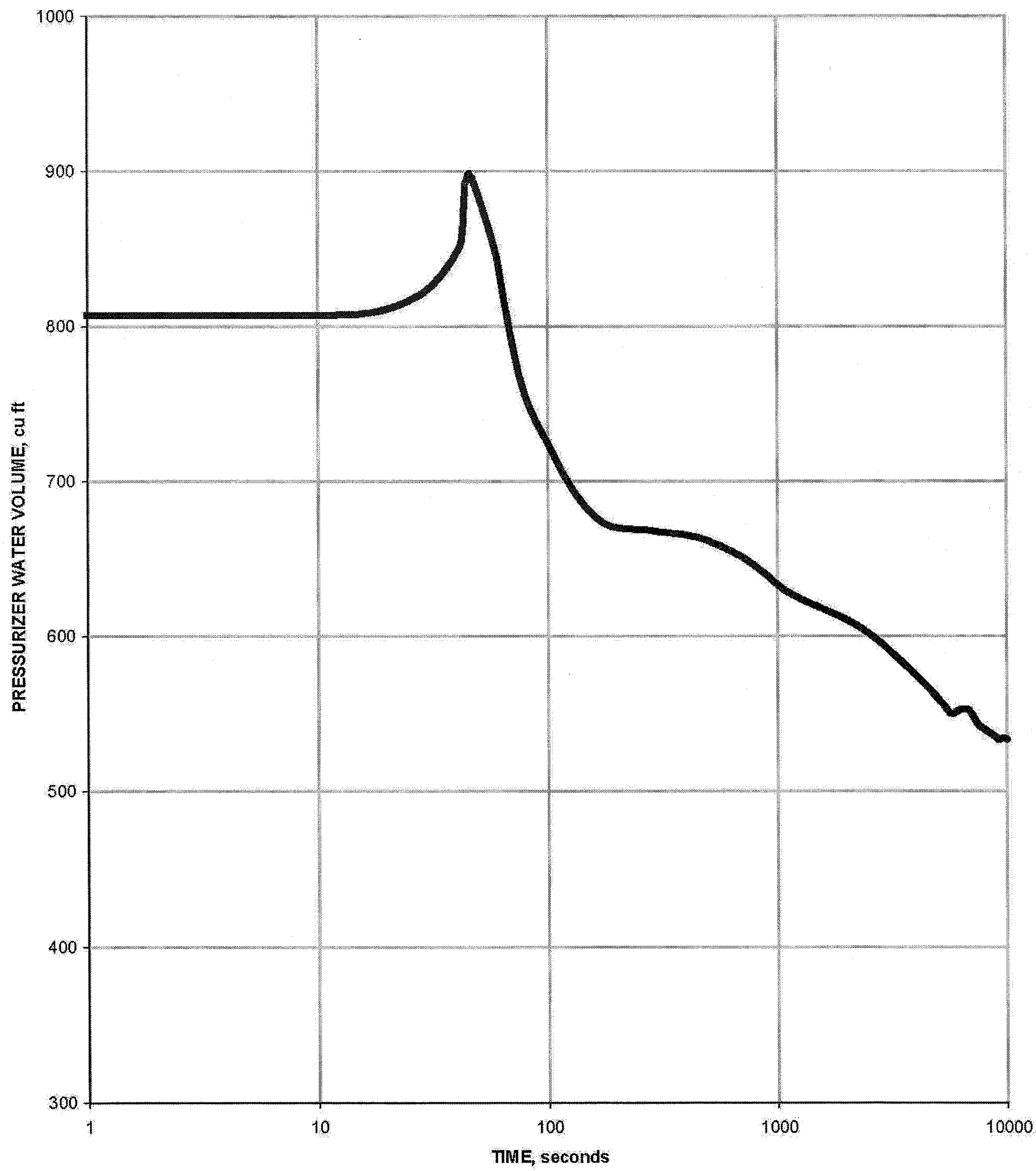


Figure 14.2-66
LOSS OF NORMAL FEEDWATER; RCS LOOP TEMPERATURE
(OFFSITE POWER NOT AVAILABLE)

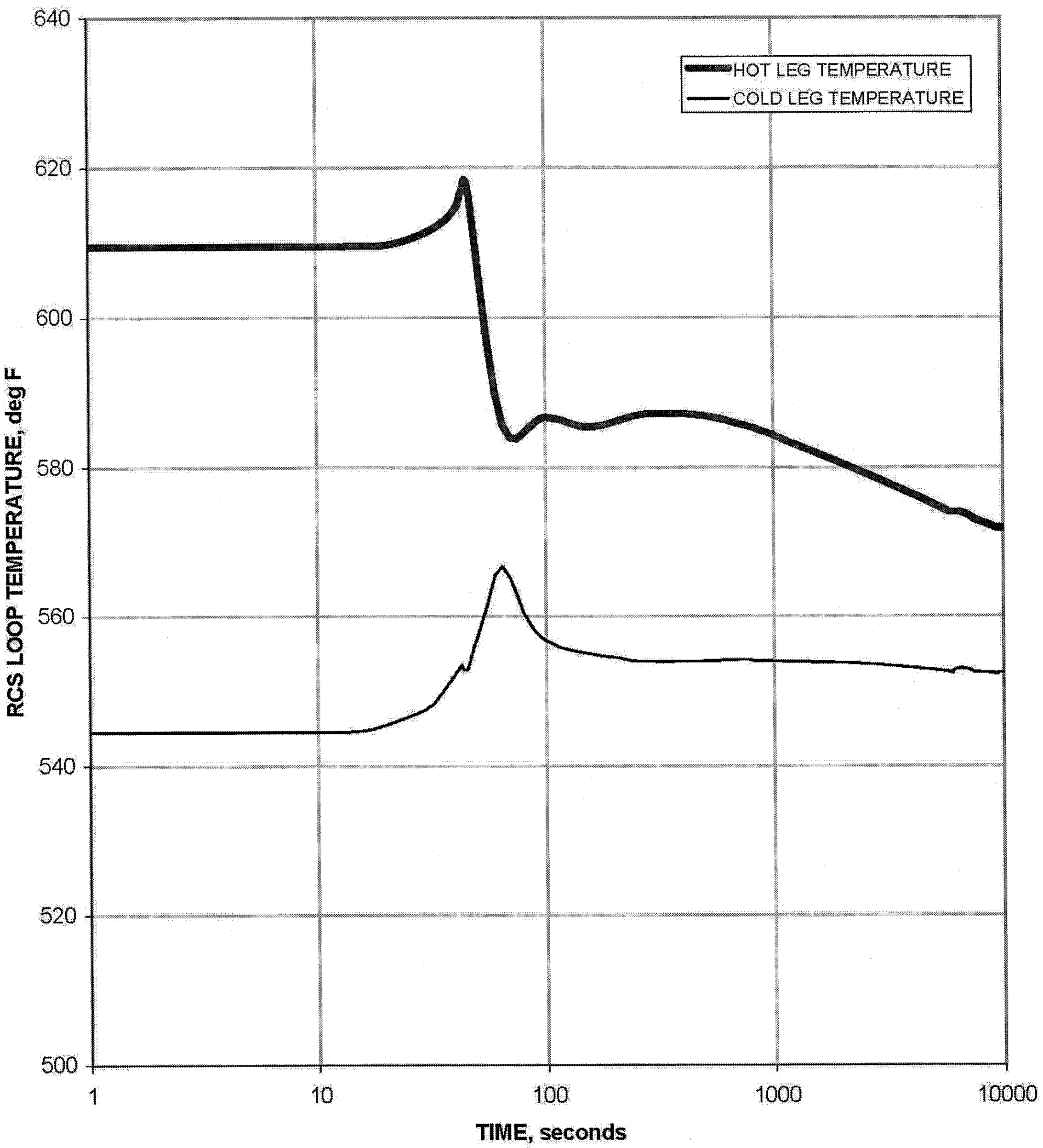


Figure 14.2-67
LOSS OF NORMAL FEEDWATER; CORE INLET FLOW
(OFFSITE POWER NOT AVAILABLE)

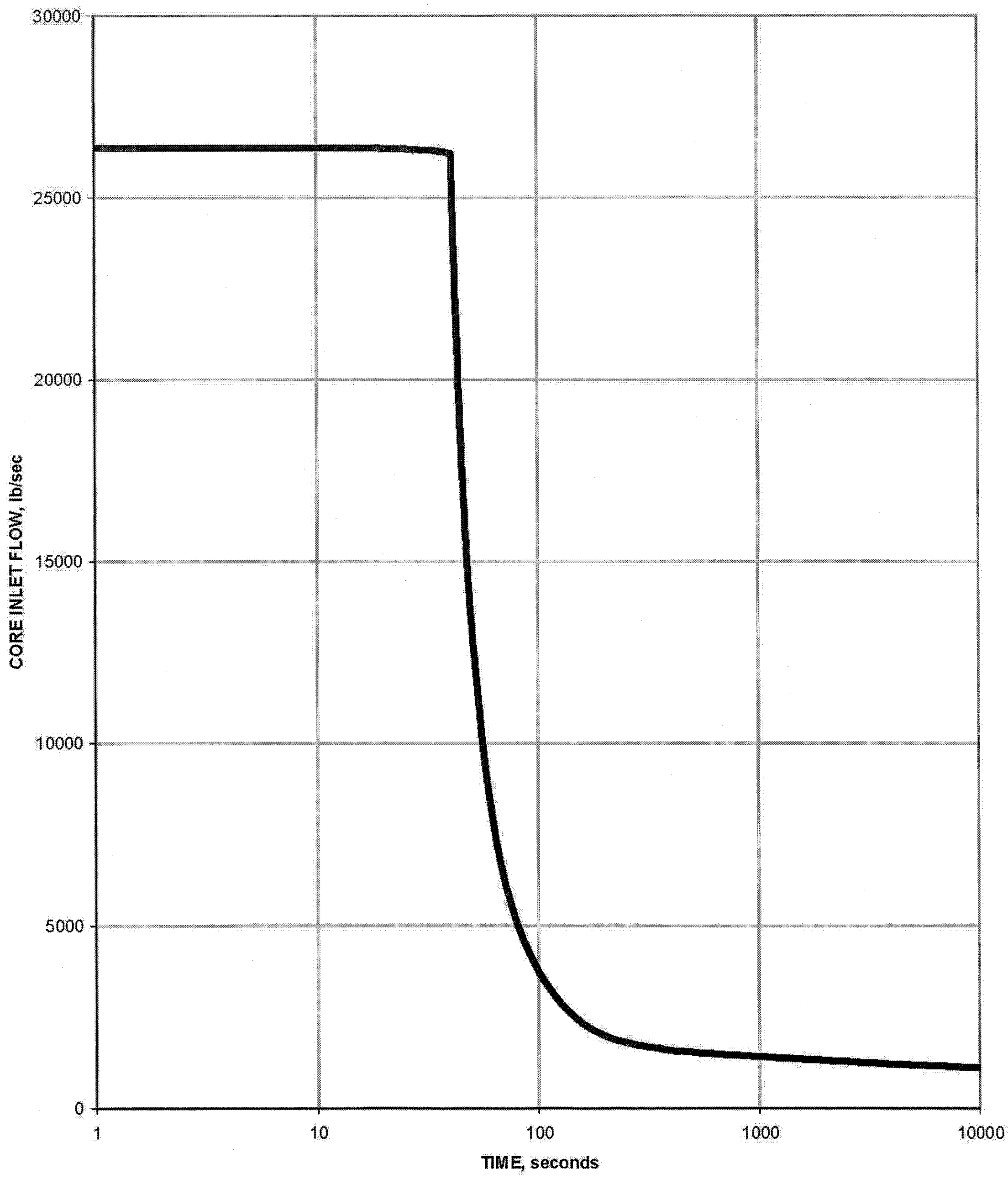


Figure 14.2-68
LOSS OF NORMAL FEEDWATER; PRESSURIZER PRESSURE
(OFFSITE POWER AVAILABLE)

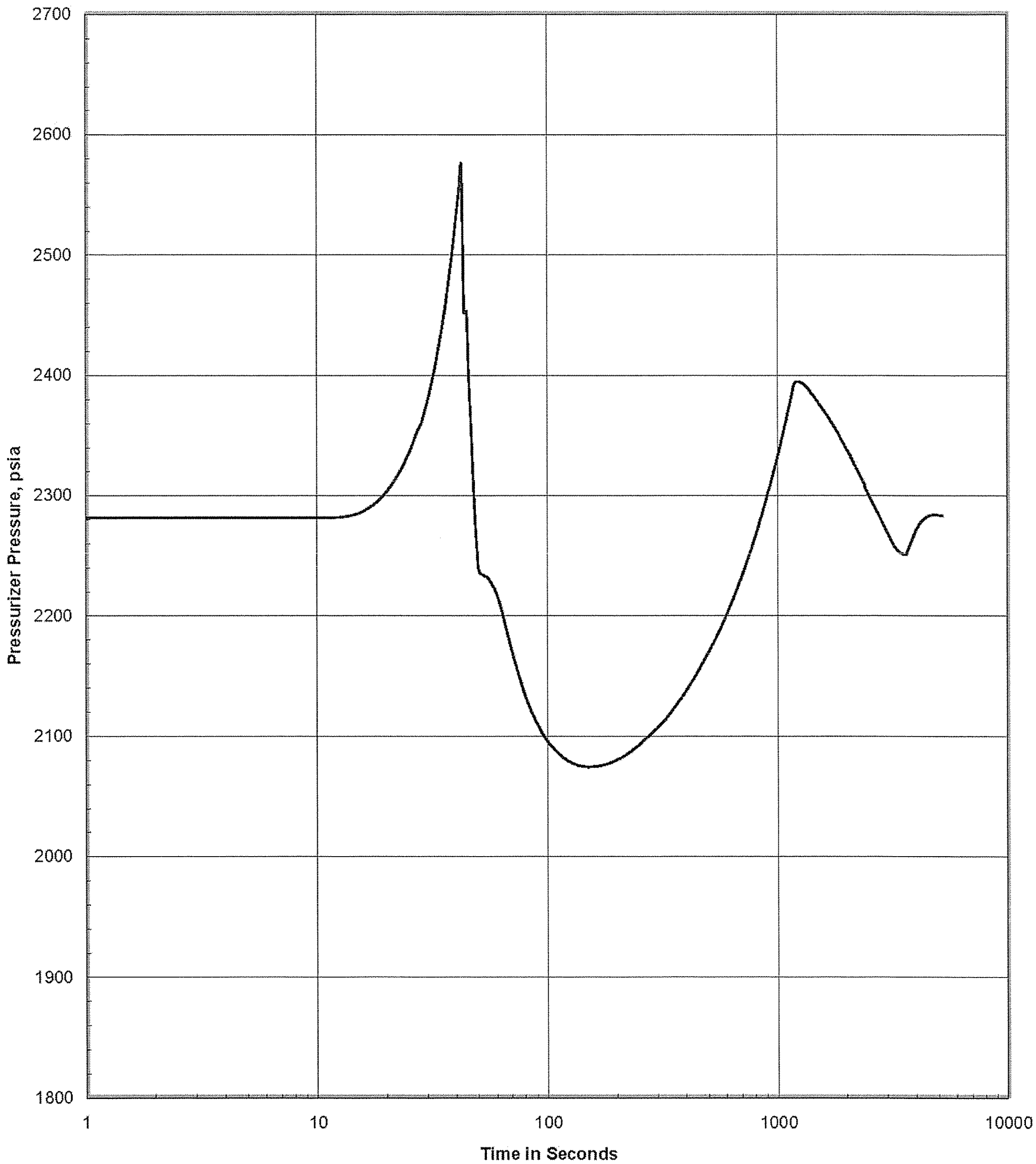


Figure 14.2-69
LOSS OF NORMAL FEEDWATER; PRESSURIZER WATER VOLUME
(OFFSITE POWER AVAILABLE)

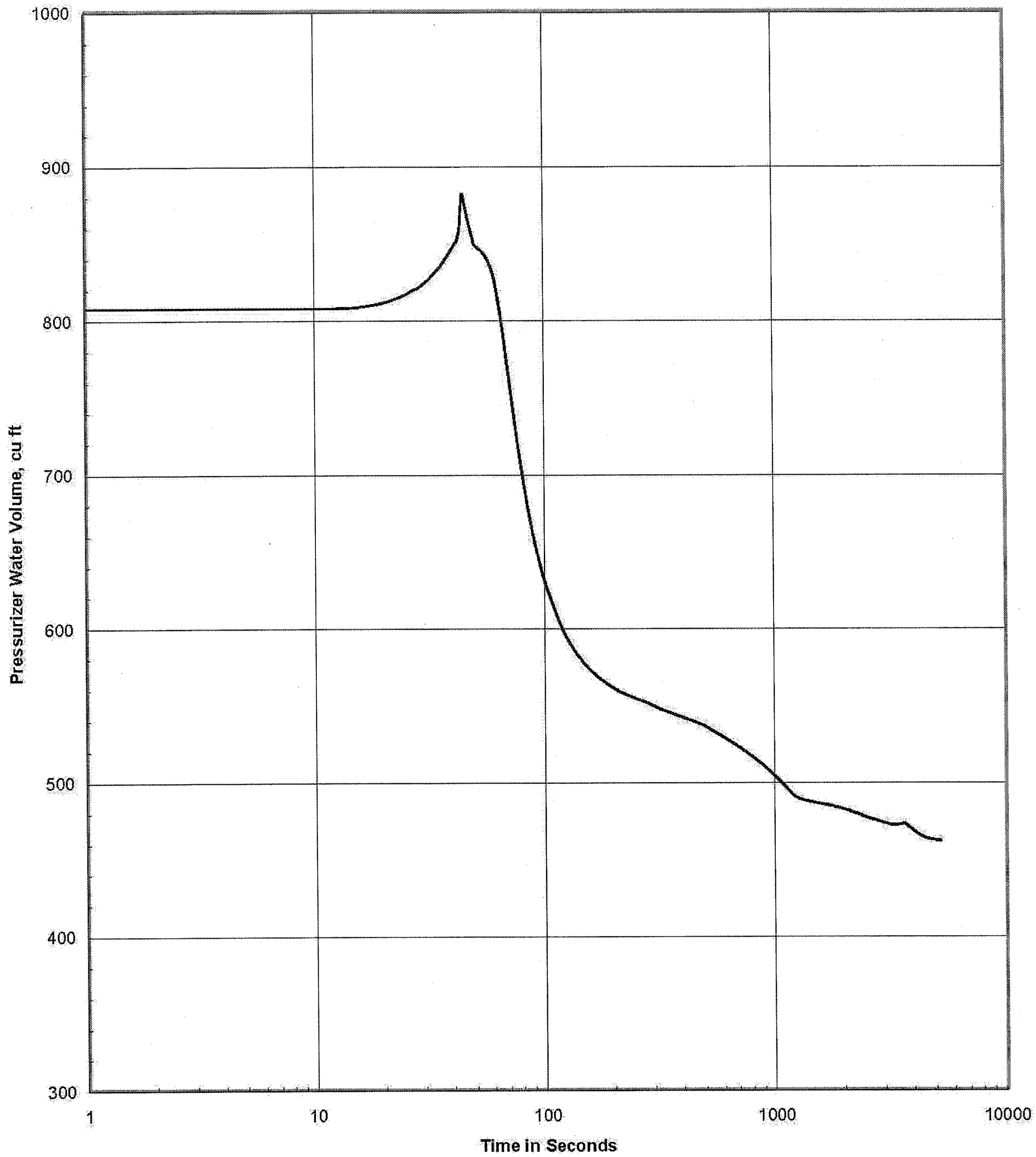


Figure 14.2-70
LOSS OF NORMAL FEEDWATER; RCS LOOP TEMPERATURE
(OFFSITE POWER AVAILABLE)

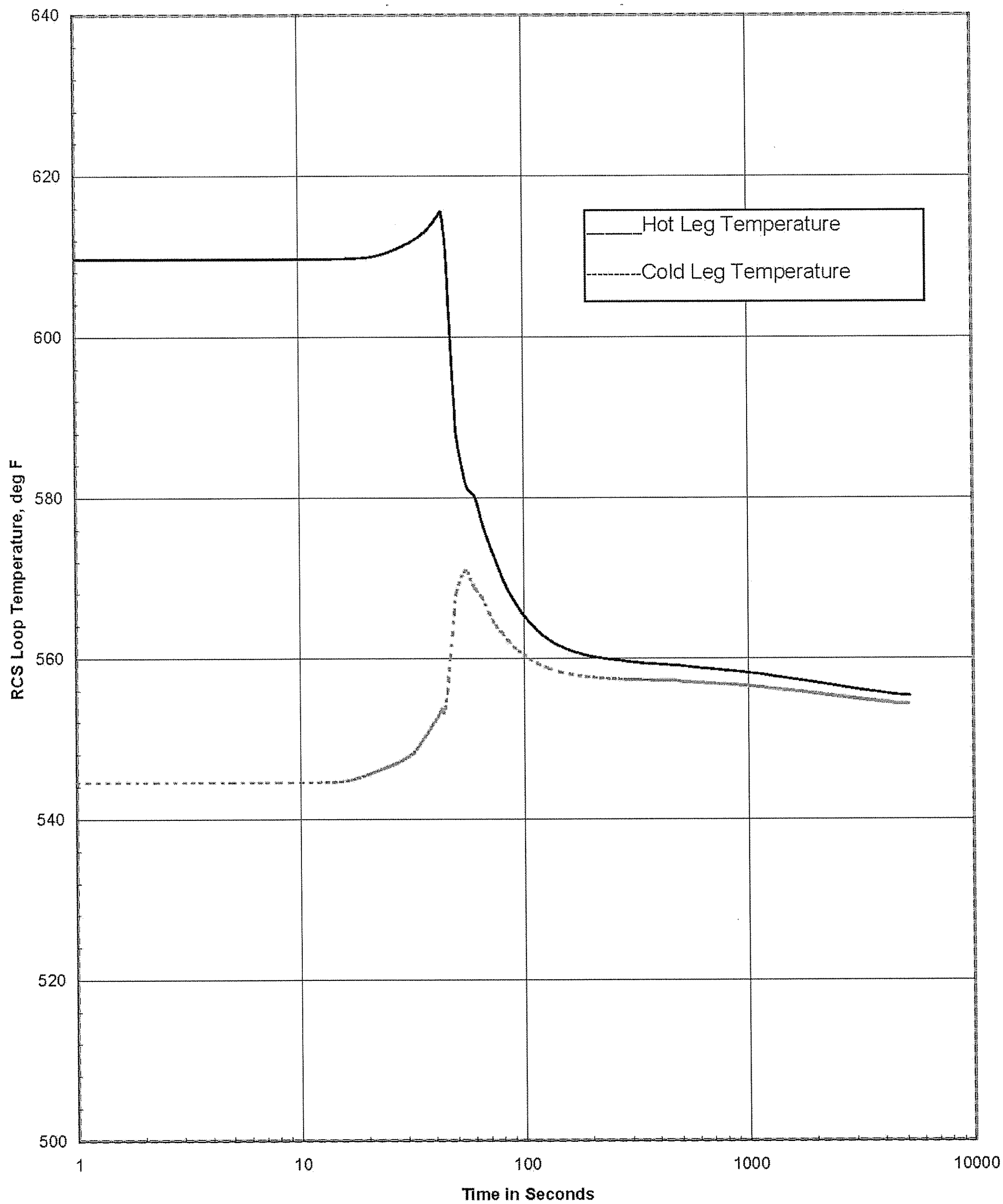


Figure 14.2-71
LOSS OF NORMAL FEEDWATER; CORE INLET FLOW
(OFFSITE POWER AVAILABLE)

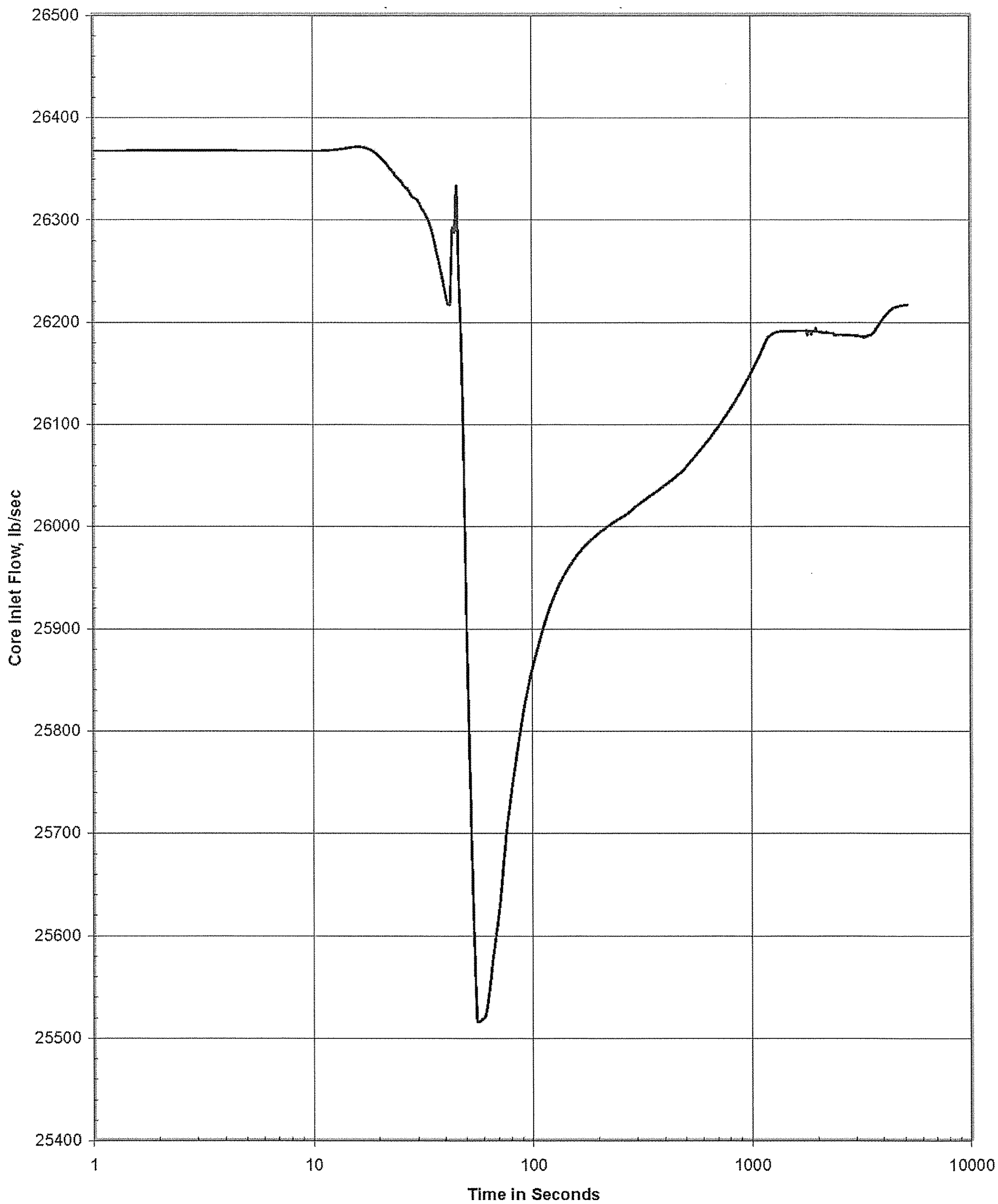


Figure 14.2-72
PROBABILITY DISTRIBUTION OF STRESS CORROSION
CRACK GROWTH RATE

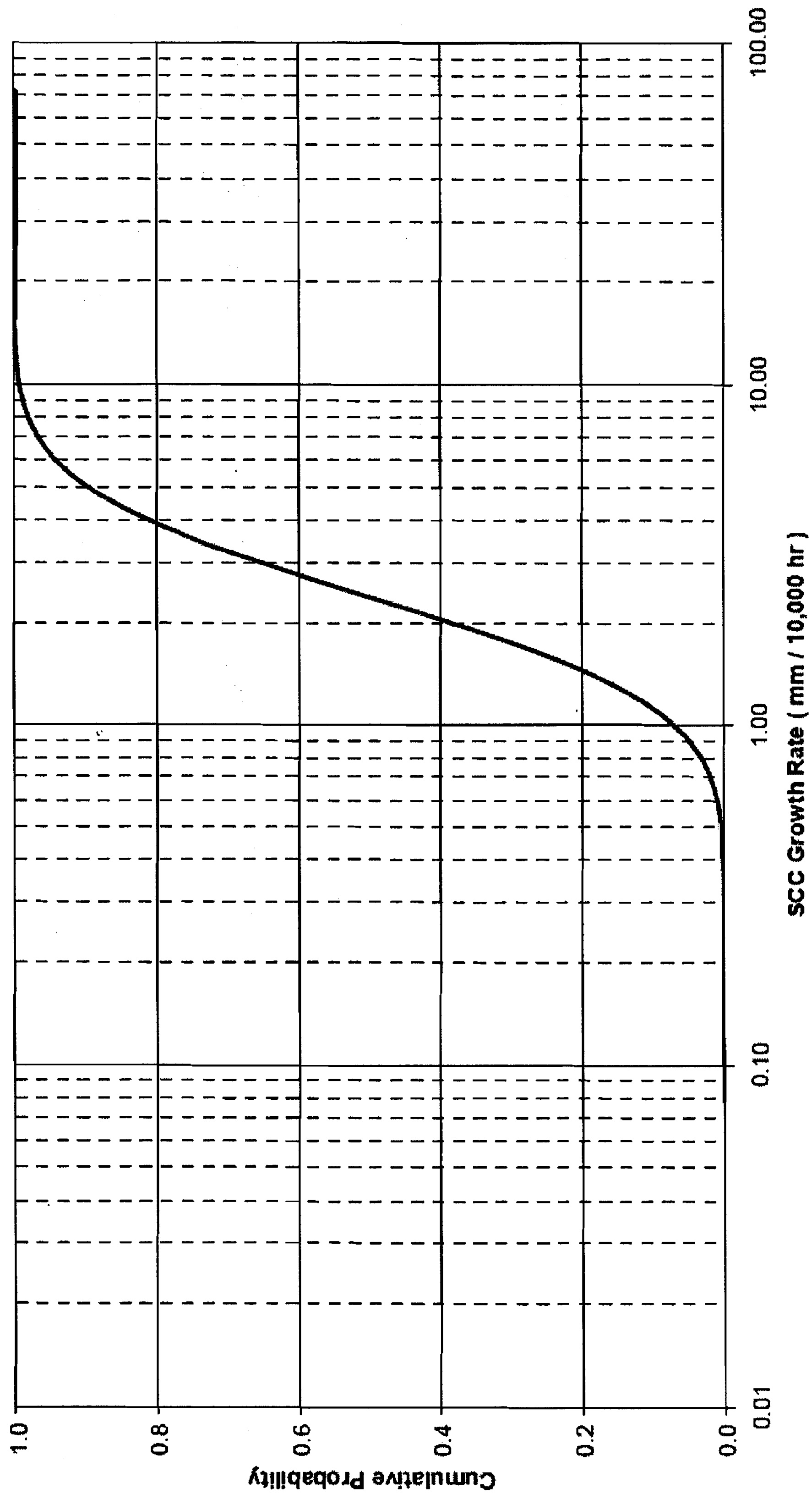


Figure 14.2-73
PROBABILITY DISTRIBUTION OF CRACK SHAPE FACTOR G

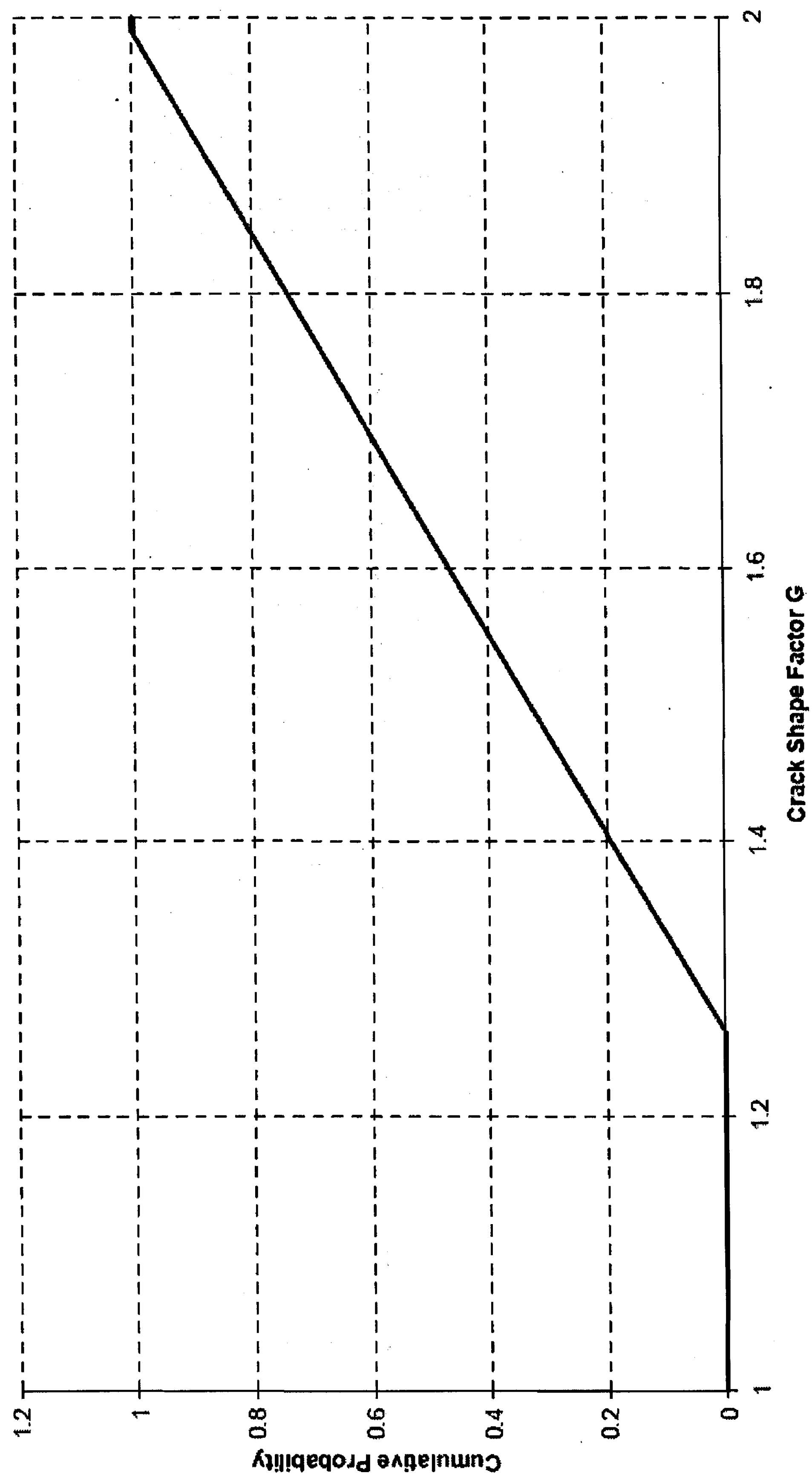
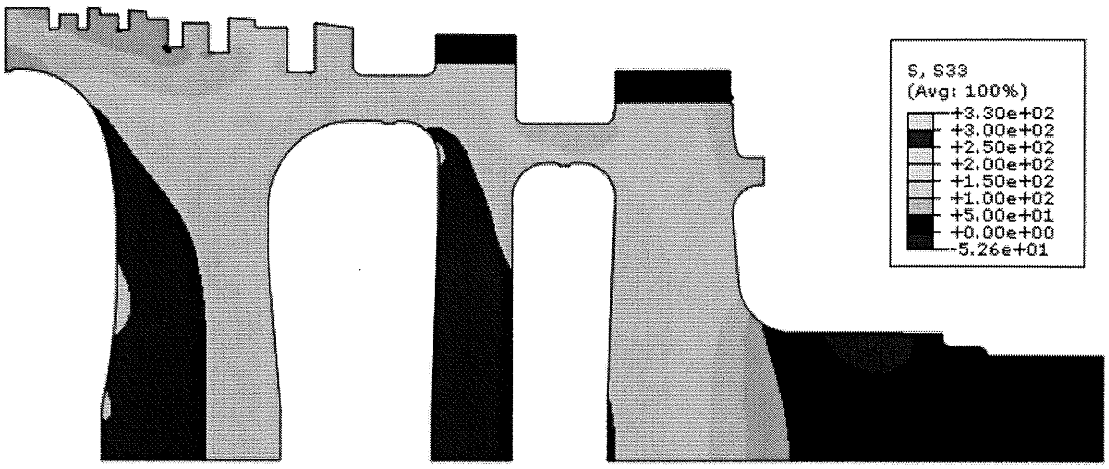
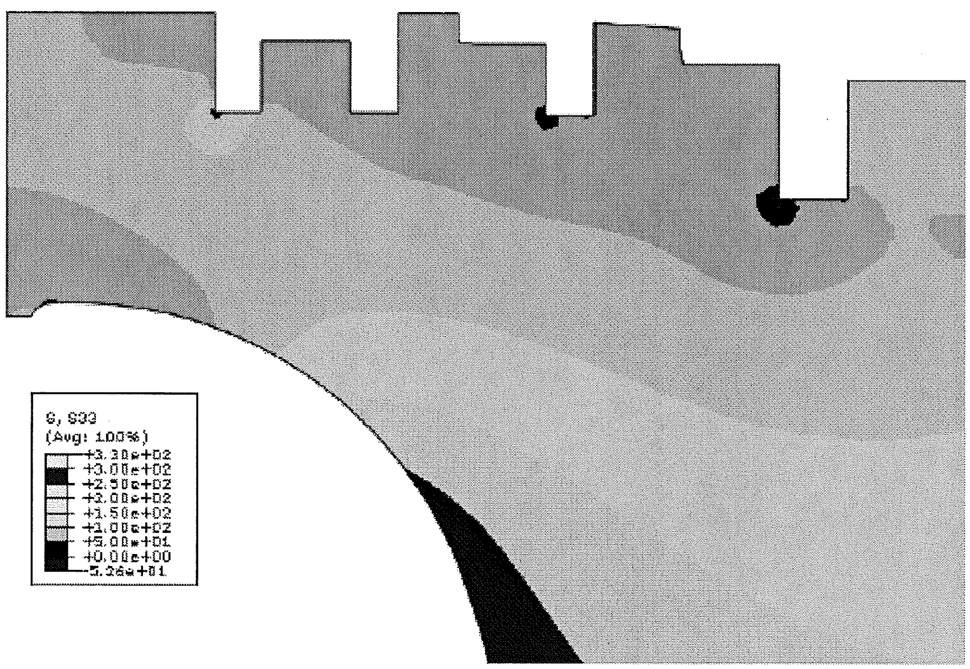


Figure 14.2-74
LP Rotor Tangential Stress Contours
LP ROTOR TANGENTIAL STRESS CONTOURS



Tangential stress contours (MPa) in steady operation



Tangential stress contours (MPa) at outside of centre disc

Figure 14.2-75
VARIATION OF CRITICAL CRACK DEPTH WITH CRACK SHAPE FACTOR G

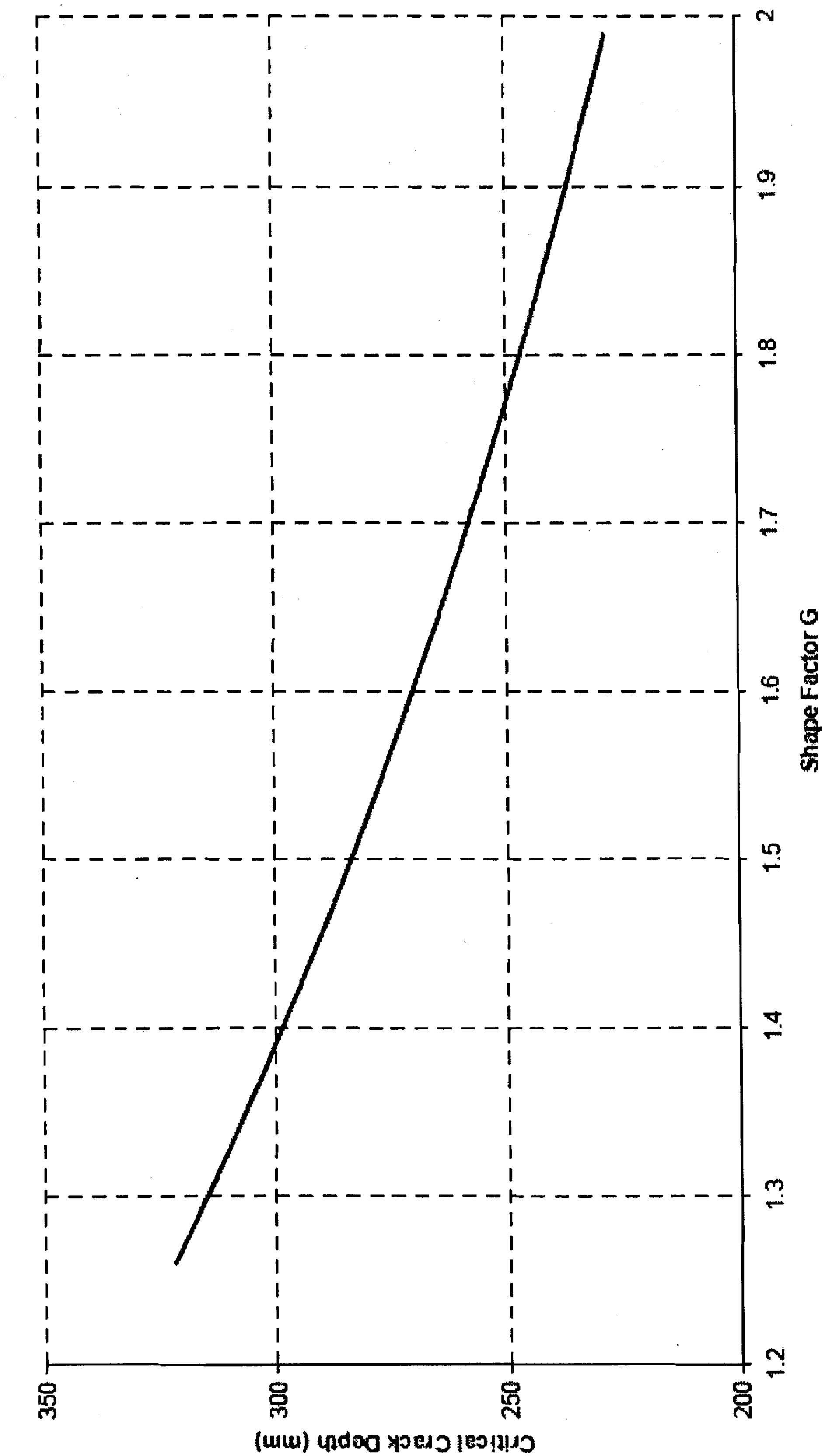
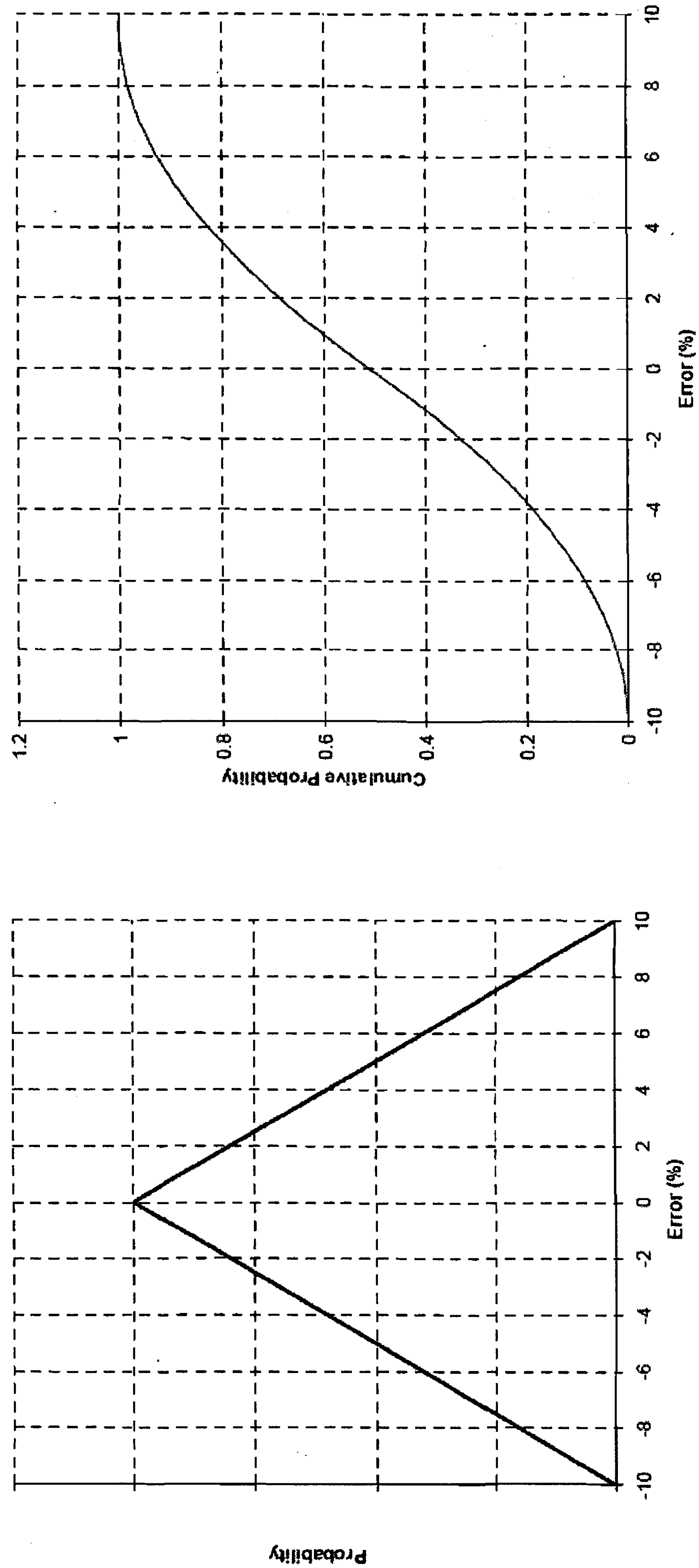


Figure 14.2-76
PROBABILITY DISTRIBUTION OF CALCULATED STRESSES



Intentionally Blank

14.3 STANDBY SAFEGUARDS ANALYSIS

14.3.1 Steam Generator Tube Rupture

14.3.1.1 Identification of Causes and Description of Accident

The accident examined is the complete severance of single steam generator tube at the limiting break location. It is assumed that the accident takes place at full power and while the reactor coolant is contaminated with the maximum concentrations allowable by the Technical Specifications, including the effects of pre-accident iodine spiking. The accident leads to the contamination of the secondary side due to the leakage of radioactive coolant from the Reactor Coolant System and, in the event of a coincidental loss of offsite power, a discharge of activity to the atmosphere through the steam generator safety valve and/or power operated relief valves and turbine driven AFW pump exhuast. The analysis presented here conservatively assumes a single power operated relief valve on the header closest to the ruptured generator sticks open following reactor trip with continued operation of the turbine driven AFW pump.

The steam generator tube material is Inconel 600, and, as the material is highly ductile, it is considered that the complete severance of a tube is extremely conservative. Surry Unit 1 and 2 steam generator tube bundles were replaced in 1979 and 1980, respectively, and operating experience since then has been extremely good.

The more probable mode of tube failure would be one or more minor leaks of undetermined origin. Activity in the Steam and Power Conversion System is subject to continual surveillance, and primary to secondary leakage during unit operation is limited to a value that is much lower than that associated with a full tube rupture. For RCS leaks in excess of 50 gpm with indications of secondary activity, the reactor is tripped, and an abnormal procedure for large steam generator tube leak is implemented which directs the operator to (a) identify and isolate secondary release paths from the ruptured generator, (SG PORVs, steam flow to the turbine driven AFW pump, etc.), (b) align the condenser air ejector discharge to containment and (c) commence unit cooldown.

Once the operator has determined a tube rupture has occurred, his first priority is to identify and isolate the affected steam generator as soon as possible in order to minimize the contamination of the secondary system and ensure the termination of any activity discharge to the atmosphere. The recovery procedure can be carried out on such a time scale as to ensure that break flow to the secondary system is terminated before the water level in the affected steam generator can rise into the main steam pipe. Sufficient indications and controls are provided to enable the operator to perform these functions satisfactorily. Training on the tube rupture accident is a significant emphasis of the licensed operator requalification program.

The following sequence of events is initiated by a tube rupture:

1. Pressurizer low pressure and low-level alarms are actuated, and, before unit trip, charging pump flow increases in an attempt to maintain the pressurizer level. On the secondary side there is a steam flow-feedwater flow mismatch before the trip as feedwater flow to the affected steam generator is reduced owing to the additional break flow that is now being supplied to that steam generator.

2. The loss of reactor coolant inventory leads to falling pressure and level in the pressurizer, and eventually a reactor trip signal is generated by overtemperature ΔT or low pressurizer pressure. Automatic unit cooldown following a reactor trip leads to a rapid change of pressurizer level, and the safety injection signal, initiated by low pressurizer pressure, follows soon after the reactor trip. The safety injection signal automatically terminates the normal feedwater supply and initiates the addition of auxiliary feedwater.

3. The steam generator blowdown liquid monitor and the air ejector radiation monitor alarm, indicating the passage of reactor coolant into the secondary system. The air ejector radiation monitor high alarm causes the air ejector exhaust from the condenser to be discharged to the containment, thereby terminating any direct atmospheric release.

4. The unit trip automatically shuts off the steam supply to the turbine and, if offsite power is available, the condenser bypass valves open to permit steam dump to the condenser. In the event of a coincidental station blackout, and loss of condenser vacuum, the condenser bypass valves would automatically close to protect the condenser. The steam generator pressure would rapidly increase and discharge steam to the atmosphere through the steam generator safety valves and/or power-operated relief valves as well as the turbine driven AFW pump exhaust.

5. Following a unit trip, the continued auxiliary feedwater supply and borated safety injection flow (supplied from the refueling water storage tank) provide a heat sink that eventually absorbs decay heat. Thus, steam bypass to the condenser, or, in the case of the loss of condenser vacuum, steam relief to the atmosphere, is discontinued on a time scale that is dependent on the exact amount of emergency equipment (safety injection pumps and auxiliary feedwater pumps) operating.

6. Safety injection flow results in an increasing pressurizer water level. The time after trip at which the operator can clearly see the returning level in the pressurizer is also dependent on the amount of operating auxiliary equipment.

14.3.1.2 **Method of Analysis and Description of the Accident**

A. Thermal-Hydraulic Analysis (Loss of Offsite Power Case)

The thermal hydraulic portion of the tube rupture accident is simulated with the Virginia Power RETRAN model (Reference 12). Key analysis assumptions were as follows:

1) A double ended tube rupture was modeled. Break flow was calculated by explicitly modeling friction losses in both segments of the ruptured steam generator tube and unchoked flow at the rupture site. This model overpredicts the actual break flows observed in the 1987 North Anna Unit 1 steam generator tube rupture. The resultant decrease in RCS pressure eventually reduces the overtemperature ΔT trip setpoint to the full power value resulting in a reactor and turbine trip.

2) Following reactor trip on overtemperature ΔT, the condenser dumps are assumed unavailable, and the secondary side pressurizes to steam generator power operated relief valve (PORV) setpoint following turbine trip.

3) The PORV on the main steam header nearest the ruptured generator is assumed to remain fully open from the time of PORV actuation until 30 minutes after event initiation. Additionally, the turbine drive AFW pump is assumed to start coincident with PORV actuation. Thus, atmospheric releases are assumed over this interval. For the normal case of condensers available, a high air ejector radiation signal diverts the air ejector exhaust to containment. Following safety injection, this exhaust path is also isolated. When offsite power and the condenser are available, the volatile species undergo two stages of partitioning (i.e., in the steam generator and the condenser) prior to being released to the atmosphere. Loss of offsite power results in loss of the condenser and in coastdown of the reactor coolant pumps, which increases the break fluid flashing fraction. Flashed break flow is a major contributor to the release of radioisotopes, as discussed in Section 14.3.1.4. Thus, the case of loss of offsite power is the limiting case from the standpoint of site boundary dose, and the analysis for this case assumes loss of the condenser and coastdown of the reactor coolant pumps after reactor trip.

4) After reactor and turbine trip, the Reactor Coolant System continues to depressurize to the safety injection setpoint. Two high head safety injection pumps are assumed to operate. The Reactor Coolant System pressure stabilizes at the point where break flow and safety injection flow are essentially equal.

5) Reactor power level used in this analysis was set at 102% of 2546 MWt or 100.38% of 2587 MWt.

B. Thermal-Hydraulic Analysis—Control Room Dose (Offsite Power Available) Case

The thermal/hydraulic analysis performed to support the calculation of control room dose is similar to that presented above. However, the calculated control room dose is more limiting under the assumption of offsite power continuing to remain available. Continued availability of offsite power would result in a potentially larger forced intake of unfiltered air from the normal control room air inlets prior to control room isolation than the case of concurrent loss of offsite power.

Therefore, the thermal/hydraulic analysis used to develop the control room calculation assumes continued operation of the reactor coolant pumps after reactor trip. However, no credit is taken for operation of the condenser dumps. As with the previous case, releases are assumed to be via a stuck open PORV on the main steam header leading from the ruptured generator along with the TDAFW exhaust.

14.3.1.3 **Results**

The thermal hydraulic results are shown in Figures 14.3-1 through 14.3-7 for the loss of offsite power case with a complete severance of a SG tube on the hot side just above the tubesheet:

Figure 14.3-1—RCS Average Temperature: Following the rupture, RCS temperature is relatively stable until the unit trips on overtemperature ΔT at 73 seconds. The turbine stop valves are assumed to close within the next 2 seconds. Temperature continues to decrease in response to addition of cold safety injection water (safety injection occurs in response to low pressurizer pressure at 223 seconds) and the release of steam through the stuck open PORV (the PORV opens at 80 seconds). In actual operating practice, additional cooldown would be imposed by the operators as directed by the emergency procedures to support primary side depressurization to reduce the break flow (assuming the affected SG's PORV was manually isolated).

Figure 14.3-2—Ruptured Loop Steam Pressure: After the reactor and turbine trip, pressure in the steam generator initially increases. The expected response would be an increase followed by stabilization at the no-load pressure of about 1005 psig, but since the analysis assumes a steam generator PORV sticks open, there is a gradual depressurization. Flow through the stuck open PORV not shown in this figure follows the same trend as the ruptured loop steam pressure in Figure 14.3-2. The flow through the stuck open PORV represents the primary potential source of radioactivity transport to the environment. Figures 14.3-4 and 14.3-5 show the integrated mass flow rate out of the faulted SG and the intact SG through the stuck open PORV and MSSV.

Figure 14.3-3—Pressurizer Pressure: The initial drop in pressurizer pressure results from excess of tube rupture flow over the charging flow. The pressurizer level controller, which would increase charging flow and tend to retard this initial depressurization, is not modeled. Immediately following reactor trip, the depressurization rate is accelerated. Safety injection is initiated on low pressurizer pressure, the depressurization drops significantly as a result.

Figures 14.3-4 and 14.3-5 – Intact and Ruptured Steam Generator Integrated Steam Releases: These figures show the integrated mass flow rate out of the faulted SG and intact SG through the open PORV, MSSV and turbine driven AFW pump exhaust. This represents the primary potential source of radioactivity transport to the environment.

Figure 14.3-6—Break Flow: The initial break flow through the two ends of the ruptured steam generator tube is about 90 lbm/sec. The flow drops off quickly in response to the RCS depressurization until safety injection is initiated. Then the flow stabilizes, as equilibrium between the break flow and safety injection is established, at about 65 lbm/sec. The slight increasing trend in mass flow beyond this point is a result of increased fluid density due to the RCS cooldown.

Figure 14.3-7—Integrated Break Flow: At one-half hour after initiation of the event, approximately 122,000 lbm of fluid has been transferred from the RCS to the secondary side of the ruptured steam generator.

14.3.1.4 Environmental Consequences of Steam Generator Tube Rupture (SGTR)

A steam generator tube rupture (SGTR) is a break in a tube carrying primary coolant through the steam generator. This postulated break allows primary liquid to leak to the secondary side of the steam generator with an assumed release to the environment through the steam generator Power Operated Relief Valves (PORVs) or the steam generator safety valves. Steam is assumed to be discharged from the affected generator to the environment until the generator is isolated at 30 minutes. The SGTR analysis used the alternative source term and followed the guidance of Regulatory Guide 1.183. Consistent with Regulatory Guide 1.183 the analysis assumed both a pre-accident iodine spike and a concurrent iodine spike.

14.3.1.4.1 SGTR Analysis Assumptions

It has been determined that tube bundle uncovery can affect doses from a Steam Generator Tube Rupture (SGTR). SGTR dose calculations follow the Westinghouse Owners Group (WOG) developed methodology (Reference 39) for this analysis. This methodology of dose calculations consists of four components:

1. Releases from secondary liquid boiling including allowance for a partition factor of 0.01 for iodine between secondary liquid and steam.
2. Releases from the fraction of primary liquid break flow that flashes to steam. A partition factor of 1 is assumed for this flashing fraction.
3. Releases from primary liquid bypassing the secondary side.
4. Releases caused by secondary moisture carryover.

As shown in Reference 39, releases from a SGTR are dominated by the first two terms above for a case with a stuck open PORV. A stuck open PORV also produces a larger radionuclide release than a cycling PORV or a PORV that fails closed, and causes the steam generator safety valves to open to relieve secondary side pressure. The RADTRAD-NAI computer model for the SGTR analysis includes terms 1, 2, and 4 discussed above.

Uncovery of the tube bundle in a SGTR does not significantly increase radionuclide releases for the stuck open PORV case. If the tube bundle is uncovered in a SGTR and the PORV is stuck open, the third release term described above increases, but it is still only a small part of the total release.

14.3.1.4.2 Initial Radioisotope Concentrations

The analyses of the SGTR accidents indicate that no additional fuel rod failures occur as a result of this transient. Thus, radioactive material releases are determined by the radionuclide concentrations initially present in primary liquid, secondary liquid and secondary steam, plus any releases from fuel rods that have failed before the transient. The analyses considered both pre-accident iodine spike cases and concurrent iodine spike cases. The discussion regarding the determination of the pre-accident and concurrent iodine spikes found in Section 14.3.2.4.2 is applicable to the SGTR as well as the main steam line break. The radionuclide inventories and concentrations for the concurrent and pre-accident iodine spike cases are shown in Tables 14.3-10 and 14.3-11, respectively.

14.3.1.4.3 Determination of χ/Q Values

The exclusion area boundary (EAB) and low population zone (LPZ) χ/Q values given in Table 14.3-13 were determined based on Regulatory Guide 1.145 methodology using meteorological data from 2009 to 2013.

During a SGTR, the condenser is conservatively assumed to be unavailable, causing the steam generators to release steam through the secondary system PORVs. Along with contaminated steam being released through the PORVs, steam is also released from the Turbine Driven Auxiliary Feed Water (TDAFW) pump exhaust. The control room χ/Q values for releases from the two steam generator release pathways to the control room normal and emergency air inlets were determined based on Regulatory Guide 1.194 methodology (Reference 34) and are given in Table 14.3-13. The control room utilizes the normal air inlet χ/Q values until the control room is isolated. After operator action is taken to actuate the emergency ventilation system, the emergency air inlet χ/Q values are used.

14.3.1.4.4 Steam Generator Tube Rupture RADTRAD-NAI Models

The RADTRAD-NAI computer code system (References 29) with Federal Guidance Report 11 and 12 dose conversion factors (References 7 & 41) was used to model the SGTR. Several RADTRAD-NAI models were created to calculate the radiological dose consequences of two cases: the pre-accident iodine spike and the concurrent iodine spike. The two cases are identical except for the initial radioisotope inventories and the inclusion of modeling of an iodine release from the fuel rods for eight hours for the concurrent iodine spike case.

The primary system mass, steam generator mass, and control room volume for the SGTR are given in Table 14.3-12. The release of the radionuclides in the steam from the intact steam generators was modeled as essentially a puff release occurring when the PORVs open. The affected steam generator release was modeled using integrated values over the time period of release (30 minutes).

The primary coolant leakage to the intact steam generators was assumed to be 1 gpm, which is conservative with respect to Surry Technical Specifications. The maximum leakage allowed by Technical Specifications is 150 gpd through any one steam generator.

For conservatism, all of this leakage was assumed to occur into the two intact steam generators. This assumption is conservative because the intact generators release steam to the environment for 10.5 hours compared to 30 minutes for the affected generator.

The break flow rates through the ruptured tube to the affected steam generator were based on the thermal hydraulic analysis of a complete double-ended tube rupture. To be consistent with the guidance in Regulatory Guide 1.183 (Reference 32), the liquid and steam break flows are modeled separately. The break flow rates and release rates to the environment are summarized in Tables 14.3-7 and 14.3-8 for the cases with and without continued availability of offsite power.

The liquid break flow through the primary system is modeled as mixing with the secondary liquid in the affected steam generator. The flow from the secondary liquid to the secondary steam is then modeled assuming a partition factor of 0.01 for iodine and moisture carryover of 1% for particulates. The fraction of the break flow that flashes to steam is modeled as being transferred to the affected steam generator steam space with no credit for scrubbing by the steam generator liquid, i.e., equivalent to tube uncovery. Once in the steam generator steam space, the radionuclides in this part of the break are almost immediately released to the environment. This technique for modeling a SGTR with uncovery of the tube bundle was developed in a generic study by the Westinghouse Owners Group (Reference 39).

The primary and secondary system releases are replaced with safety injection and auxiliary feedwater flows. Therefore, the mass of the primary and secondary liquids remains relatively constant during this transient.

The radionuclide inventory in the steam generators is modeled based on the initial inventory, the primary to secondary leakage, and the break flow rates and release rates to the environment that are discussed above. Flow through the condenser was not modeled because it was unavailable for the loss of offsite power case and because modeling the condenser reduces dose consequences.

The model for the control room ventilation system for the SGTR is set up to accurately model the timing of the sequence of events of the SGTR accident. The start of the accident is the tube rupture itself. The PORV on the faulted steam generator was determined to open 80 seconds after the break, and the SI signal is generated at 182 seconds for the case assuming continued availability of offsite power. For the case assuming loss of offsite power, the PORV on the faulted steam generator was determined to open 80 seconds after the break, and the SI signal is generated at 223 seconds. The timing of these events was extracted from the thermal-hydraulic analysis.

Prior to the isolation of the control room with offsite power available, the control room is being supplied via the normal ventilation system with a 3300 cfm intake air flow rate until loss of offsite power or control room isolation, whichever is earlier. The control room isolates automatically 20 seconds after the initiation of the SI signal. Emergency ventilation is assumed to provide a filtered breathing air supply of 900 cfm within 1 hour of the SGTR until the end of the accident. An unfiltered leakage of 0 or 250 cfm is assumed for the entire time the control room is isolated. The control room intake filter efficiency assumed is 90% and 70% for elemental and organic iodine, respectively. All other non-noble gas isotopes modeled are filtered at 99% efficiency.

14.3.1.4.5 Results of Dose Calculations for SGTR

Both pre-accident and concurrent iodine spike cases were analyzed for the steam generator tube rupture. The limiting case for the control room dose was determined to be a pre-accident iodine spike with continued availability of offsite power. This dose is shown in Table 14.3-9 and corresponds to 0 cfm of unfiltered control room inleakage. For 250 cfm of unfiltered control room inleakage the calculated dose is demonstrated to go down slightly. This result is attributed to the decreased average residence time for radionuclides in the control room with the higher inleakage.

Table 14.3-9 also shows a comparison of the doses calculated for the limiting SGTR accident scenario with the GDC-19 criteria. All calculated control room doses for the Surry steam generator tube rupture remain below the GDC-19 criteria.

The limiting case for the EAB and LPZ was determined to be a concurrent iodine spike with loss of offsite power. The EAB and LPZ doses shown in Table 14.3-9 are less than the Regulatory Guide 1.183 limits for concurrent iodine spike cases.

14.3.1.5 **Recovery Procedure**

The immediately apparent symptoms of a tube rupture accident, such as falling pressurizer pressure and level and increased charging pump flow, can also be symptoms of small steam-line breaks and loss-of-coolant accidents. It is therefore important that the operator determine that the accident is the rupture of a steam generator tube in order to carry out the correct recovery procedure. This accident is uniquely identified by a condenser air ejector radiation alarm or a steam generator blowdown radiation alarm, and the operator does not proceed with the following recovery procedure unless these alarms are observed. In the event of a relatively large rupture, such as that analyzed above and shown in Figures 14.3-1 to 14.3-6, it is clear soon after the trip that the level in one steam generator is rising more rapidly than those in the others. This indication is used in identifying the affected steam generator.

The analysis described above takes no credit for operator action for the first 30 minutes. In an actual event, within 30 minutes the operators would be expected to achieve the following:

1. Ensure that power is available to the emergency buses and that safety injection and auxiliary feedwater are actuated. Verify that main feedwater is isolated.

2. Control the reactor system cooldown to maintain no-load temperature. Stop the reactor coolant pumps if safety injection flow to the core is indicated and the minimum required RCS subcooling is not maintained.
3. If not already completed, identify the ruptured steam generator by rising water level or high steam line radiation indications and isolate flow from this steam generator. Adjust auxiliary feedwater flow to maintain the specified water levels in the affected and intact steam generators.

Completion of these steps terminates the release of radioisotopes. For the analysis case discussed above, following termination of flow from the stuck PORV in the ruptured generator, more than 15 additional minutes would elapse prior to repressurizing the steam generator to the nominal PORV relief setpoint (Reference 40), assuming no additional operator actions. In practice, upon completion of identification and isolation of the ruptured generator, the following additional actions are performed:

1. Initiate RCS cooldown through the intact steam generators by dumping steam to the main condenser or through the steamline PORV (depending on the availability of offsite power). Following a loss of offsite power, the steam generator PORVs can not be operated remotely from the main control room because the control circuits are powered from a semi-vital source. However, a backup bottled air system has been provided so that the SG PORVs can be operated from within the Containment Spray Pump House. A second backup bottled air system is also provided inside the Main Steam Valve House, which is a safety-related, seismic structure that is tornado missile protected.
2. Depressurize the RCS to minimize break flow and refill the pressurizer using the pressurizer spray or the pressurizer PORVs. Maintain the RCS pressure within the pressure-temperature limit curve for the Reactor Coolant System.
3. Terminate safety injection flow upon meeting the SI termination criteria.
4. Establish normal letdown and charging functions and control RCS pressure to minimize primary-to-secondary leakage.
5. Initiate appropriate post-SGTR cooldown procedures.

These additional actions limit the potential for any additional releases from the affected generator following the isolation step.

The generic analyses of Reference 40 show that the stuck PORV case yields higher releases than the case where the PORV on the affected generator cycles normally. For cases where less than a full double-ended tube rupture occurs, it may take the operator longer to perform the RCS depressurization step. However, for this case, the break flow rate will also be lower. Therefore, although in specific event scenarios some limited additional relief from cycling of the affected generator's PORV might occur beyond 30 minutes, the analysis cases presented here are bounding in terms of total integrated release and therefore radiological consequences. Based on observation of the relative releases cited for the stuck PORV, cycling PORV and cycling main steam safety valves in Section 9 of Reference 40, the stuck PORV analysis presented here bounds the following scenarios:

1. SGTR with the ruptured SG's PORV cycling at its nominal setpoint; releases terminated at approximately 37 minutes.
2. SGTR with the ruptured SG PORV isolated and the associated main steam safety valve(s) cycling at the nominal setpoint. Releases terminated well beyond 1 hour.
3. Any case above with a break area corresponding to less than a double-ended tube rupture (initial break flow rate of 800 gpm).

14.3.2 Rupture of a Main Steam Pipe

A rupture of a main steam pipe (the pipes that carry steam from the steam generators to the main turbine) is assumed to include any accident that results in an uncontrolled steam release from a steam generator. The release can occur as a result of either a break in a pipe line or a valve malfunction. The steam release results in an initial increase in steam flow, which decreases during the accident as the steam pressure falls. The energy removal from the reactor coolant system causes a reduction of reactor coolant temperature and pressure. With a negative moderator temperature coefficient, the cooldown results in a reduction of the core shutdown margin. If the most reactive control-rod assembly is stuck in its fully withdrawn position, there is a possibility that the core will become critical and return to power, even with the remaining control-rod assemblies inserted. A return to power following a main steam pipe rupture is a potential problem mainly because of the high hot-channel factors that exist when the most reactive rod is stuck in its fully withdrawn position. Assuming the worst combination of circumstances that could lead to the resumption of power generation following a main steam line break, the core is ultimately shut down by the boric acid in the safety injection system.

The analysis of a main steam pipe rupture is performed to demonstrate that:

1. Assuming a stuck control-rod assembly with or without offsite power, and assuming a single failure in the engineered safety features, there is no consequential damage to the primary system and the core remains in place and intact.
2. There will be no DNB or clad perforation resulting from any single active failure in the main steam system. The single active failure is the opening, with failure to close, of the largest of any single steam bypass, relief, or safety valve.
3. Energy release to containment from the worst steam pipe break does not cause failure of the containment structure.

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis shows that no DNB occurs for any rupture, even in the event that the most reactive control-rod assembly is stuck in its fully withdrawn position.

The following systems provide the necessary protection against a main steam pipe rupture:

1. Safety injection system actuation by any of the following (see Chapter 7 for logic details):
    a. Two out of three pressurizer low pressure signals.
    b. Two out of three differential pressure signals between any main steam line and the main steam header.
    c. High steam flow in two out of three main steam lines (one out of two per line) in coincidence with either low reactor coolant system average temperature (two out of three) or low main steam line pressure (two out of three).
    d. Three out of four high containment pressure signals.
    e. Manual intervention.
2. The overpower reactor trips (neutron flux and delta T) and the reactor trip occurring upon actuation of the safety injection system.
3. Redundant isolation of the steam generator feedwater lines. Sustained high feedwater flow would cause additional cooldown; thus, in addition to the normal control action that closes the main feedwater valves, any safety injection signal rapidly closes all feedwater control valves, trips the steam generator feedwater pumps, and closes the feedwater pump discharge valves.

    The feedwater isolation function is primarily accomplished by safety grade feedwater control valves and feedwater control valve bypass valves. The feedwater isolation design does not include safety grade back-up isolation capability. However, the automatic trip of the main feedwater pumps and closure of the feedwater pump isolation valves accomplishes the back-up feedwater isolation function. The reliance upon commercial grade isolation equipment as back-up feedwater isolation has been accepted as a generic industry position as documented in NUREG-0138. The failure of a feedwater control valve or bypass valve to close upon a feedwater isolation signal has been evaluated and shown to be bounded by the assumptions in the limiting analysis described in this section.
4. The trip of the fast-acting main steam line trip valves (designed to close within 10 seconds from the time the process variable reaches the trip setpoint) on:
    a. High steam flow in two out of three main steam pipes (one out of two per line) in coincidence with either low reactor coolant system average temperature (two out of three) or low steam line pressure (two out of three).
    b. Three out of four high containment pressure signals.

Each main steam line has a fast-closing trip valve and a nonreturn valve. These six valves prevent the blowdown of more than one steam generator for any break location in a main steam pipe, even if one valve fails to close. For example, for a break upstream from the trip valve in one line, the closure of either the nonreturn valve in that line or the trip valves in the other lines prevents the blowdown of the other steam generators.

All Surry steam generators are equipped with integral flow restrictors at the generator outlet. The restrictors have a smaller flow area than the main pipe and serve to reduce the largest effective break area which must be considered to 1.4 ft^2.

A special case of this event is a main steam line break in the main steam valve house (outside containment). The transient is described in Section 14B.6.

14.3.2.1 **Method of Analysis**

The analysis of the main steam pipe rupture has been performed to determine:

1. The core heat flux and reactor coolant system temperature and pressure resulting from the cooldown following the steam-line break. The analysis was performed with the RETRAN (Reference 12) computer code. The calculation describes the plant neutron kinetics, the reactor coolant system including natural circulation, the pressurizer, steam generators and feedwater system. The digital program computes pertinent variables including the break flow rate, core power and point kinetics reactivity and primary coolant temperatures.
2. The thermal and hydraulic behavior of the core following a steam-line break. The 15 x 15 Upgrade fuel design was analyzed to determine if DNB has occurred using the VIPRE-D code (Reference 42) for the core conditions computed in 1 above. These calculations solve the continuity, momentum, and energy equations of fluid flow in the core, and with the Westinghouse W-3 (Reference 2) or WLOP (Reference 42) correlations determines the DNB margin.

The following assumptions were made:

1. A 1.77% delta k/k shutdown reactivity from all but one control rod assembly at no-load conditions. This is the end-of-life design value, including design margins for the case in which the most reactive control-rod assembly is stuck in its fully withdrawn position. The actual shutdown capability is expected to be significantly greater.
2. The negative moderator coefficient corresponding to the end-of-life core with all but the most reactive control-rod assembly inserted. The variation of the coefficient with temperature has been included. In computing the power generation following a steam-line break, the local reactivity feedback from the high neutron flux in the region of the core near the stuck control-rod assembly has been included in the overall reactivity balance. The local reactivity feedback is composed of Doppler reactivity from the high fuel temperatures near the stuck control-rod assembly and moderator feed back from the high water temperature near the stuck control-rod assembly. The Doppler reactivity feedback corresponds to a most negative hot zero power Doppler temperature coefficeint. For the cases in which steam generation occurs in the high flux regions of the core, the effect of void formation on the reactivity has also been included. The effect of power generation in the core on overall

reactivity is shown in Figure 14.3-8. The curve assumes end-of-life core conditions with all control-rod assemblies in except the most reactive control-rod assembly, which is assumed to be stuck in its fully withdrawn position (completely removed from the core).

3. Minimum safety injection capability corresponding to the operation of only one high head safety injection pump. The most restrictive single failure corresponds to the flow delivered by one charging pump delivering its full flow to the cold leg header. A boron concentration of 2300 ppm was assumed in the Refueling Water Storage Tank (RWST), from which the safety injection pumps take suction. Boron enters the safety injection system after the charging pump suction switches over from the volume control tank to the refueling water storage tank upon safety injection actuation.

   The assumed single failure for the steamline break analysis is the failure of one safeguards train to function, thus maximizing the delay time for boron to reach the core. Other failures that could affect the severity of the transient are bounded by the failure of a safeguards train.

   The initial boron concentration in the Boron Injection Tank (BIT) and the associated safety injection piping is assumed to be zero. The time delays incurred prior to the delivery of the 2300 ppm boron have been included in the analysis. These time delays are conservatively based on the SI system design which included a 900-gallon boron injection tank (BIT). The BIT has been subsequently removed from the SI system on both units (Reference 4). An evaluation of this change against the criteria of 10 CFR 50.59 showed that the main effect of removing the BIT was to significantly reduce the time delay required to sweep unborated water from the SI piping following a safety injection signal, which would be a benefit from a safety analysis standpoint. Thus, the steamline break analyses based on a BIT at 0 ppm are conservative and bound the current condition with the BIT removed.

4. Hot-channel factors corresponding to one stuck control-rod assembly, i.e. the control-rod assembly giving the highest factor at the end of life. The hot-channel factors account for the void existing in the locality of the stuck control-rod assembly at the pressure that occurs during the return-to-power phase following the steam break. This void, in conjunction with the large negative moderator coefficient, partially offsets the effect of the stuck control-rod assembly. The hot-channel factors depend on the core temperature, pressure, and flow, and are therefore different for each case studied. The calculations used to obtain the hot-channel factors again assume end-of-life core conditions with all control-rod assemblies in except the most reactive control-rod assembly.

5. Three combinations of break sizes and initial unit conditions were considered in determining the core power and reactor coolant system transient:

   a. The complete severance of a main steam pipe, initially at no load conditions with offsite power available. The presence of the integral flow restrictors in the steam generators will control the steam release rates for all break locations, both inside and outside the containment.

b. Case A above with loss of offsite power immediately before the steam break.

c. A break larger than or equal to the capacity of any single steam dump or safety valve from one steam generator with offiste power available (credible break).

All the cases above assume initial hot-shutdown conditions with the control-rod assemblies inserted (except for one stuck control-rod assembly) at time zero. Should the reactor be just critical or operating at power at the time of a main steam line break, the reactor is tripped by the normal overpower protection system when the power level reaches a trip point or by the safety injection signal from the steamline break protection functions. Following a trip at power, the reactor coolant system contains more stored energy than at no load, the average coolant temperature is higher than at no load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the main steam line break before the no-load conditions of reactor coolant system temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis that assumes a no-load condition at time zero. However, since the initial steam generator mass is greatest at no load, the magnitude and duration of the reactor coolant system cooldown are less for main steam line breaks occurring at power.

1. In determination of the critical flux at which burnout could occur, the W-3 or WLOP Correlation may be used. This was considered to be the correlation that most accurately represented the range of parameters produced in the transients analyzed.
2. In computing the steam flow during a steam-line break, the Moody Critical Flow Model (Reference 3) was used.

14.3.2.2 **Results**

The results presented are a conservative indication of the events that would occur assuming a main steam line rupture, since it is postulated that all of the conditions above occur simultaneously.

14.3.2.2.1 Core Power and Reactor Coolant System Transient

Figures 14.3-9 through 14.3-13 show the reactor coolant system transient and core heat flux following a main steam pipe rupture (complete severance of a pipe) at initial no-load conditions (Case A). The break assumed is the largest break that can occur anywhere in the system. Offsite power is assumed available such that full reactor coolant flow exists. The transient shown assumes that the control-rod assemblies are inserted at time 0 (with one control-rod assembly stuck in its fully withdrawn position) and steam is released from only one steam generator after closure of the steamline trip valves. Should the core be critical at near zero power when the rupture occurs, the initiation of safety injection by high differential pressure between any steam generator and the main steam header or by high steam flow signals in coincidence with either low reactor coolant system temperature or low steam-line pressure. The current bounding main steam line break analysis assumes a 5-second delay from the time the measured process variables (e.g., steam line flow, steam line pressure) reach the main steam line setpoints to the initiation of main steam trip valve motion, followed by an additional 5-second ramp closure of the valves.

The acceptance criteria for a satisfactorily full closure test of a trip valve is defined in the Basis of Technical Specification 4.7-2 (Reference 26). With the high flow existing during a main steam line rupture, the valves will close considerably faster since their closure is flow assisted.

Tables 14.3-1 through 14.3-3 outline the sequence of events and Tables 14.3-4 and 14.3-5 the transient statepoint parameters for the three main steamline break cases. Figures 14.3-9 through 14.3-23 plot the transient results for several key parameters in the offsite power case, loss of offsite power case, and credible break case, respectively.

As shown in Figure 14.3-9 through 14.3-13, the core attains criticality with the control-rod assemblies inserted (with the design shutdown, assuming one stuck control-rod assembly) before boron solution enters the reactor coolant system from the safety injection system. The delay time consists of the time to receive and actuate the safety injection signal and the time to completely open or realign valve trains in the safety injection lines. The safety injection pumps are then ready to deliver flow. At this stage a further delay time is incurred before boron solution can be injected to the reactor coolant system, due to 0% boron concentration water being swept from the safety injection lines. No credit was taken for any boron in the safety injection lines entering the reactor coolant system prior to the 2300 ppm boric acid from the refueling storage tank. The case attains a peak core power well below the nominal full power value.

The calculation assumes the boric acid is mixed with and diluted by the water flowing in the reactor coolant system before entering the reactor core. The concentration after mixing depends on the relative flow rates in the reactor coolant system and in the safety injection system. The variation of mass flow rate in the reactor coolant system due to water density changes is included in the calculation, as is the variation of flow rate in the safety injection system due to changes in the reactor coolant system pressure. The safety injection system flow calculation includes the line losses in the system as well as the pump head curve.

Figures 14.3-14 through 14.3-18 show the responses of the core parameters for Case B, which corresponds to the case discussed above with loss of offsite power at the time the main steamline break occurs. The safety injection system delay time includes 10 seconds to start the diesel and 10 seconds for the safety injection pump to reach full speed. Criticality is reached later in the transient and the core power increase is slower than in the similar case with offsite power available. The ability of the emptying steam generator to extract heat from the reactor coolant system is reduced by the decreased flow in the reactor coolant system. The peak core power remains well below the nominal full power value.

It should be noted that, following a main steam-line break, only one steam generator blows down completely. Thus, two steam generators are still available for the dissipation of decay heat after the initial transient is over. In the case of loss of offsite power, this heat is removed to the atmosphere, the atmospheric safety valves having been sized to cover this condition.

Figures 14.3-19 through 14.3-23 show the responses of the core parameters resulting from a steam release with an initial steam flow typical of the capacity of any single steam dump or safety valve. In this case, safety injection is initiated automatically by low pressurizer pressure. The limited cooldown resulting from the stuck open valve results in the transient reaching criticality much later in the transient than in the other cases. Sufficient negative reactivity remains to limit the peak heat flux to approximately 7% of the rated power. With the reactor coolant pumps still providing full flow, the case is bounded in terms of minimum DNBR by the offsite power case in Case A, severance of a main steam pipe.

The evaluation of Reference 5 demonstrates that even with 0 ppm boron in the BIT, the containment design bases are met for steam line break. As discussed previously, removal of the BIT provides an analysis benefit with respect to the case of 0 ppm in the BIT, by reducing the time delay for introducing borated water to the core. This reduced time delay will result in a more rapid shutdown and, therefore, reduced mass and energy release to the containment.

14.3.2.3 **Margin to Critical Heat Flux**

Using the transients shown in Figures 14.3-9 through 14.3-23, the 15 x 15 Upgrade fuel design is analyzed with the VIPRE-D/W-3 code/correlation pair or the VIPRE-D/WLOP code/correlation pair (Reference 42) to determine the margin to DNB. Carefully chosen points from each transient were examined, and the results showed that all three cases have a minimum DNBR greater than the applicable SAL (Section 3.2.3). The power and flow statepoint conditions are shown together with pressure and inlet core temperature in Table 14.3-4 and 14.3-5.

14.3.2.4 **Environmental Consequences of a Main Steam-Line Break (MSLB)**

A Main Steam Line Break (MSLB) involves the postulated double ended failure of one of the steam lines carrying steam from a steam generator to the turbine generator. Two cases have to be considered: Loss of Offsite Power (LOOP) and Offsite Power Available (no-LOOP). Both cases assume that the break occurs in the turbine building to maximize does consequences. The no-LOOP case models the turbine building as recirculating the air in the building at the maximum capability of the emergency exhaust fans. The LOOP case assumes that the exhaust fans do not have power in order to operate. Therefore, only natural recirculation is modeled in the LOOP case. The MSLB analysis used the alternative source term and followed the guidance of Regulatory Guide 1.183.

Because the MSLB releases are assumed to occur in the turbine building, the normal χ/Q methodology used for the control room does not apply. χ/Q is used to determine the concentration of a radioisotope χ in Ci/m^3 from the release rate Q in Ci/sec. The control room χ/Q is normally determined with the methodology of Reference 34 based on the distance between release and receptor points and site meteorology. Depending on the type of release, building wake effects may also be considered. For the MSLB, the releases occur in the same building as the control room emergency inlet, so the ARCON96 χ/Q methodology does not apply. Therefore, the direct pathway from the steam line break to the turbine building was modeled along with the intake of control room air from the turbine building.

14.3.2.4.1 MSLB Analysis Assumptions

There is no control room χ/Q defined for a situation when the releases are into the same building where the inlet to the control room is located. Therefore, for the MSLB it was necessary to use a different approach to model the transport of radioactive steam releases from the broken steam line to the control room. (Normal χ/Q methodology is applicable to the modeling of the releases through the intact steam generators.)

The control room is modeled in the RADTRAD-NAI computer code as having three intakes: two intakes from the environment (filtered and unfiltered) and one directly from the Turbine Building. The intake pathways from the environment utilize time-dependent χ/Q values, while the intake pathway from the Turbine Building does not. This modeling approach accounts for the assumption that the release is in the same building as the inlet to the control room.

As a starting point for the MSLB analysis, the concentrations of each radioisotope in the primary and secondary liquid were determined. Radionuclides are released with the steam from these sources through the break. These MSLB release rates are shown in Table 14.3-14.

The flow rates used in this analysis considered the volume expansion that occurs when pressurized liquid or steam is discharged from the steam generator to the turbine building. The flow rate from the steam generator to the turbine building was based on the density of steam or liquid inside the steam generator, while the flow rate from the turbine building to the environment was based on the expansion of steam to atmospheric pressure inside the turbine building. This MSLB model is summarized below.

14.3.2.4.2 Initial Radioisotope Concentrations

For the MSLB, the radioactive material releases are determined by the initial radionuclide concentrations present in primary and secondary liquid, plus any releases from failed fuel rods. The amount of activity in the primary and secondary coolant at the initiation of the MSLB is assumed to be the maximum levels allowed by the plant Technical Specifications.

Consistent with RG 1.183 (Reference 32), both a pre-accident iodine spike and a concurrent iodine spike were considered for the MSLB. For Surry, the maximum iodine concentration allowed in Surry Technical Specifications for an iodine spike is 10 μCi/gm dose equivalent I-131. RG 1.183 defines a concurrent iodine spike as an accident initiated increase in the release rate of iodine from failed fuel rods to a value 500 times the release rate corresponding to the Technical Specification dose equivalent iodine limit for normal operations. (For the SGTR accident, the concurrent spike release rate of iodine from failed fuel rods is set to a value 335 times the release rate corresponding to the Technical Specification dose equivalent iodine limit for normal operations.) In addition to the Technical Specification dose equivalent iodine concentrations and to bound the release rate expected during normal operations; the release rate was determined assuming hot full power conditions, a letdown flow rate of 120 gpm, a primary system leak rate of 11 gpm (10 gpm identified and 1 gpm unidentified), primary-to-secondary leakage of 450 gpd (150 gpd per steam generator) and a letdown decontamination efficiency of 100%. The concurrent iodine spike term of 500 times the release rate is also known as the concurrent iodine spike appearance rate. A concurrent iodine spike is more likely than a pre-accident spike since the pressure change caused by an accident can increase iodine releases from failed fuel rods. A pre-accident iodine spike is unlikely, since some independent event would have had to occur shortly before the accident to cause the spike.

The primary coolant Technical Specification activity concentrations are given in Table 14.3-10. The total primary and secondary radionuclide inventories are derived from these values using the masses of the respective systems. The secondary coolant radionuclide concentrations are assumed to be 10 percent of the primary coolant activity. This accounts for the secondary coolant activity Technical Specification limit being a factor of 10 less than the primary Technical Specification limit. The pre-accident spike activity and the concurrent iodine spike rate are given in Table 14.3-11. The secondary side activity levels are initially the same (at the Technical Specification secondary activity limit) for the pre-accident and concurrent spike cases. Only the primary liquid activities differ. The concurrent iodine spike case assumes the primary coolant activity is initially at the steady state activity limit of 1 μCi/gm dose equivalent I-131 shown in Table 14.3-10, with iodine added at the appearance rates shown in Table 14.3-11. The pre-accident spike case assumes the primary coolant iodine activity is initially at the short term Technical Specifications limit of 10 μCi/gm dose equivalent I-131 and the remainder of the primary coolant isotopes are at the steady state activity limit of 1 μCi/gm dose equivalent I-131 shown in Table 14.3-10. The isotopic concentrations and iodine spike values in Tables 14.3-10 and 14.3-11 are derived from RCS 1% Failed Fuel concentrations shown in Table 14.3-16, which are based on a core power of 2605 MWt and nominal 18 month operating cycles, by normalizing to the Technical Specifications limits for primary and secondary liquid dose equivalent I-131 using CEDE dose conversion factors from FGR 11. These inventories were input to the RADTRAD-NAI code system to calculate doses from an MSLB. The masses of the primary liquid, secondary liquid and secondary steam used in this MSLB dose analysis are listed in Table 14.3-12.

14.3.2.4.3 Determination of χ/Q Values

The EAB and LPZ atmospheric dispersion factors (χ/Q) are given in Table 14.3-13 and were determined based on Regulatory Guide 1.145 methodology using meteorological data for 2009 to 2013.

The intact steam generators are assumed to release steam through the secondary system steam relief valves and Turbine Driven Auxiliary Feed Water (TDAFW) pump exhaust. Using the ARCON96 methodology, the control room χ/Q values shown in Table 14.3-13 were determined for releases from the intact generators.

14.3.2.4.4 Main Steam Line Break RADTRAD-NAI Models

The RADTRAD-NAI computer code system (Reference 29) with Federal Guidance Report 11 and 12 dose conversion factors (References 7 & 41) was used to model the MSLB. RADTRAD models were created to calculate the radiological dose consequences of two cases: the pre-accident Iodine spike and the concurrent accident spike. The two models are identical except for the initial radioisotope inventories and the inclusion of modeling of an iodine release from the fuel rods for eight hours for the concurrent iodine spike case.

The flow rates from the primary coolant to the steam generators prior to the start of the accident were based on conservatively assumed leak rates with respect to Technical Specifications. The maximum leakage from one generator was assumed to be 500 gpd into the generator affected by the steam line break. The maximum leak rate allowed by the Technical Specifications is 150 gpd through any one steam generator.

The affected steam generator was modeled as discharging through the turbine building, while the other two generators were modeled as discharging directly to the environment. The flow rates from the affected steam generator liquid to the turbine building and from the turbine building to the environment are summarized in Table 14.3-14.

All of the iodine being released is conservatively assumed to be airborne. In practice, some of the steam generator discharge would be as water, which would retain some of the iodine in the liquid phase.

The mass release in thirty minutes (Table 14.3-14) is several times the initial mass of the affected steam generator. The mass released from the affected steam generator to the turbine building was increased above the calculated values to ensure that substantially all of the radionuclides initially present in the affected steam generator were released.

Because the affected steam generator is essentially emptied of liquid during the MSLB, no partitioning of iodine between the liquid and steam is assumed for discharges from the affected generator. A partition factor of 0.01 for the iodine isotopes and a moisture carryover of 1% for the particulate isotopes were assumed for the intact generators. The flow rate from the turbine building to the environment considered the expansion of the steam as the pressure is reduced to atmospheric in the turbine building. In addition, because the turbine building is not a sealed building, air flow through the building was considered. The building has a forced ventilation system capable of approximately one volume exchange every six minutes.

However, this forced ventilation system would not function after a loss of offsite power. One volume exchange per hour is a reasonable air flow rate for the turbine building without forced ventilation. For conservatism, the LOOP case assumed a 0.2 volume/hour air flow rate. A forced ventilation of 12 volumes/hour was used in the no-LOOP case when forced ventilation is available.

The model for the control room ventilation system for the MSLB is set up to accurately model the timing of the sequence of events of the MSLB accident. The start of the accident is the steam line break itself. Steam is released from the intact steam generators safety relief valves during the first 11 seconds of the MSLB. The SI signal is generated at 16 seconds for the case assuming continued availability of offsite power and at 19 seconds for the case assuming loss of offsite power. The timing of these events was extracted from the thermal-hydraulic analysis.

Prior to the isolation of the control room with offsite power available, the control room is being supplied via the normal ventilation system, with a 3300 cfm intake air flow rate. The control room isolates automatically 20 seconds after the initiation of the SI signal. For the LOOP case, the normal ventilation system is assumed to not be operating. Emergency ventilation is assumed to provide a filtered breathing air supply of 900 cfm within 1 hour of the MSLB until the end of the accident. An unfiltered inleakage of 250 cfm is assumed for the entire control room is isolated. The control room intake filter efficiency assumed is 90% and 70% for elemental and organic iodine, respectively. All other non-noble gas isotopes modeled are filtered at 99% efficiency.

14.3.2.4.5 Results of Dose Analysis for MSLB

The control room, EAB and LPZ doses calculated for the MSLB are shown in Table 14.3-15. The limiting accident scenario for the calculation of the doses was determined to be a concurrent iodine spike case. The calculated control room dose from a MSLB is below the GDC-19 criteria. The doses calculated for a MSLB at the EAB and LPZ are less than the RG 1.183 limits for concurrent iodine spike cases.

14.3.2.5 **Conclusions**

Although DNB and possible clad perforation (no clad melting or zirconium-water reaction) following a steam pipe rupture are not necessarily unacceptable, the above analysis, in fact, shows that DNB does not occur for any rupture, assuming the most reactive rod stuck in its fully withdrawn position.

The minimum DNBRs determined in the analysis of the steamline break are greater than the applicable SAL (Section 3.2.3).

14.3.3 Rupture of a Control Rod Drive Mechanism Housing (Control Rod Assembly Ejection)

14.3.3.1 **Identification of Causes and Accident Description**

This accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of a rod cluster control assembly and drive shaft. The consequence of this mechanical failure is a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

14.3.3.1.1 Design Precautions and Protection

Certain features in Westinghouse pressurized water reactors are intended to preclude the possibility of a rod-ejection accident, or to limit the consequences if the accident were to occur. These include a sound, conservative mechanical design of the rod housings, a thorough quality control (testing) program during assembly, and a nuclear design that lessens the potential ejection worth of rod cluster control assemblies and minimizes the number of assemblies inserted at power.

14.3.3.1.1.1 Mechanical Design. The mechanical design is discussed in Section 3.5. Mechanical design and quality control procedures intended to preclude the possibility of a rod cluster control assembly (RCCA) drive mechanism housing failure sufficient to allow a rod cluster control assembly to be rapidly ejected from the core are listed below:

1. Each Unit 1 control rod drive mechanism housing is completely assembled and shop-tested at 3450 psig. Each Unit 2 control rod drive housing is hydrostatically tested at the shop at 3107 psig.
2. The mechanism housings are checked during the system leak test of the reactor coolant system.
3. Stress levels in the mechanisms are not affected by anticipated system transients at power, or by the thermal movement of the coolant loops. Moments induced by the design-basis earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class A components.
4. The Unit 1 latch mechanism housing and rod travel housing are each a single length of forged type 304 stainless steel. The Unit 2 latch mechanism housing and rod travel housing are each a single length of forged type 316 stainless steel. These materials exhibit excellent notch toughness at all temperatures that will be encountered.

The Unit 1 joints between the latch mechanism housing and head adapter, and between the latch mechanism housing and rod travel housing, are threaded joints reinforced by canopy-type rod welds. The Unit 2 joints between the latch mechanism housing and head adapter housing are threaded joints reinforced by canopy type welds. The Unit 2 joints between the latch mechanism housing and rod travel housing are butt welds. Administrative regulations require periodic inspections of these (and other) welds.

14.3.3.1.1.2 Nuclear Design. Even if a rupture of a rod cluster control assembly (RCCA) drive mechanism housing is postulated, the operation of a plant using chemical shim is such that the severity of an ejected rod cluster control assembly is inherently limited. In general, the reactor is operated with the RCCAs inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated for by boron changes. Further, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of a RCCA-ejection accident. Therefore, should a rod cluster control assembly be ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may occasionally be desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the rod cluster control assemblies above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all rod cluster control assemblies is continuously indicated in the control room. An alarm will occur if a bank of rod cluster control assemblies approaches its insertion limit or if one assembly deviates from its bank. There are low-low-level insertion monitors with visual and audio signals.

14.3.3.1.1.3 Reactor Protection. The reactor protection in the event of a rod-ejection accident has been described in Reference 13. The protection for this accident is provided by the high-neutron-flux trip (high and low setting). This protection function is described in detail in Section 7.2.

14.3.3.1.1.4 Effects on Adjacent Housings. A control-rod drive mechanism assembly is shown in Chapter 3. The operating coil stack assembly of this mechanism has a 10.718-inch by 10.718-inch cross section and is 39.875 inch in length. The position indicator coil stack assembly is located above the operating coil stack assembly. It surrounds the rod travel housing over nearly its entire 163.25-inch length. The rod travel housing outside diameter is 3.75 inch and the inside and outside diameters of the position indicator coil stack assembly are 3.75 and 7 inches, respectively. This assembly consists of a Micarta tube surrounded by a continuous stack of copper-wire coils. This assembly is held together by two end plates, an outer sleeve, and four axial tie rods.

14.3.3.1.1.4.1 Effects of Rod Travel Housing Longitudinal Failures. Should a longitudinal failure of the rod travel housing occur, the region of the Micarta tube opposite the break would be stressed by the reactor coolant pressure of 2250 psia. The most probable leakage path would be the radial deformation of the position indicator coil assembly, resulting in the growth of axial flow passages between the rod travel housing and the Micarta tube. The development of a radial free-water jet would be unlikely because of the small clearance between the Micarta tube and the rod travel housing, and the considerable resistance of the combination of the Micarta tube and the position indicator coils to internal pressure.

Calculations based on experimental data on the mechanical properties of Micarta and copper at reactor operating temperature show than an internal pressure of at least 2500 psia would be necessary for the combination of the Micarta tube and the coils to start leaking in a radial direction between the Micarta glass filaments.

The normal operating environment of the Micarta tube is strictly controlled during unit operation, and thus no deterioration of the Micarta is expected. Should for unknown reasons the mechanical strength of the Micarta tube be reduced and a longitudinal crack occur in a control-rod assembly housing, weepage flow between the Micarta filaments and the copper coil wires might take place, but no free jet should be formed. The formation of a free jet implies a cracking of the Micarta tube, which could occur only with internal pressure substantially in excess of reactor operating pressure. Prolonged exposure to hot water might cause a deterioration of the Micarta and radial leakage might increase; even under these conditions, however, a net radial free jet would be improbable.

A position indicator coil assembly has to maintain its integrity after a housing failure only until the remaining control-rod assembly can be tripped into the core. Should for unknown reasons a failure of the position indicator coil assembly occur after reactor trip, the resulting free radial jet from the failed housing could cause the housing to bend and come into contact with adjacent rod travel housings. If the adjacent housings were on the periphery, they could conceivably bend outward from their bases. The housing material is quite ductile and plastic hinging without cracking could be expected. Rod travel housings adjacent to a failed housing in locations other than the periphery would not be bent because of the rigidity of multiple adjacent housings.

14.3.3.1.1.4.2 Effect or Rod Travel Housing Circumferential Failures. If a circumferential failure of a rod travel housing were to occur, the broken-off section of the housing would be ejected vertically because the driving force is vertical. The position indicator coil stack assembly and the drive shaft would tend to guide the broken-off piece upward during its travel. Travel would be limited to less than 3 feet (Unit 1) or about 15 inches (Unit 2, due to the integral missile shield) by the missile shield, thereby limiting the projectile acceleration. When the projectile reached the missile shield, it would partially penetrate the shield and dissipate its kinetic energy. The water jet from the break would continue to push the broken-off piece against the missile shield.

If the broken-off piece of the rod travel housing were short enough to clear the break when fully ejected, it would rebound after impact with the missile shield. The top-end plates of the position indicator coil stack assemblies would prevent the broken piece from directly hitting the rod travel housing of a second drive mechanism. Even if a direct hit by the rebounding piece were to occur, the low kinetic energy of the rebounding projectile would not be expected to cause significant damage.

14.3.3.1.2 Limiting Criteria

Due to the extremely low probability of a RCCA-ejection accident, limited fuel damage is considered an accepatable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy have been carried out as part of the SPERT project by the Idaho Nuclear Corporation (Reference 14). Extensive tests of Zirconium-clad UO_2 fuel rods representative of those in pressurized-water-reactor-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 15) results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreases by about 10% with fuel burnup. The clad failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise), even for irradiated rods, did not occur below 300 cal/gm.

In view of the above experimental results, conservative criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

1. Average fuel pellet enthalpy at the hot spot below 225 cal/gm for unirradiated fuel and 200 cal/gm for irradiated fuel.
2. Peak clad temperature at the hot spot below the temperature at which clad embrittlement may be expected (2700°F). (Reference 25).
3. Peak reactor coolant pressure less than 3000 psi, which is much less than that which would cause damage to the reactor coolant system.
4. Fuel melting limited to less than 10% of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of criterion 1 above.

14.3.3.2 **Analysis of Effects and Consequences**

14.3.3.2.1 Method of Analysis

Previous analyses of this event are documented in the original FSAR, and in References 9 and 16 through 21 and 27. The initial FSAR analysis was performed by Westinghouse. The calculation was done in two stages: an average core calculation, and then a hot region calculation. The nuclear power transients for the average core calculation were calculated using the CHIC-KIN code developed by the Bettis Atomic Power Laboratory (Reference 22) to solve the point kinetics equations. A detailed heat transfer code, which employed the Tong, Sandberg and Bishop correlation (Reference 23) to determine the film boiling heat transfer coefficient after DNB, was then used for the hot region calculations.

References 16 and 17 updated the original analysis to accommodate the higher end of life (EOL) ejected rod worths and peaking factors realized for Cycle 2 operation at both units.

The Reference 18 analysis was performed to reflect a positive moderator temperature coefficient at beginning of cycle (approximately 3 pcm/F at zero power, decreasing to 1.5 pcm/F at full power). These calculations were done by Westinghouse using the TWINKLE code for the nuclear power transient and the FACTRAN code for the hot spot heat transfer calculations. The method of analysis is given in WCAP-8117 (Reference 24), and the basis for the calculation and the Westinghouse limit criteria is given in WCAP-7588 (Reference 10).

These same models and methods were used for the reanalyses in References 19 and 20. These evaluations were performed because the Cycle 3 reload core design for each unit resulted in violations of one or more of the following design limits: the ratio of the rod worths to the delayed neutron fraction, the peaking factors; maximum ejected rod worths, or minimum delayed neutron fractions.

The analysis in Reference 9 was performed to establish new design limits when the minimum delayed neutron fractions for the Surry 1 Cycle 5 reload design were less than the applicable limits. The Westinghouse models and methods were again used for this analysis.

The rod ejection analysis in Reference 21 was performed to evaluate the impact of the increased drop time associated with the SIF assemblies.

The rod ejection analysis in Reference 27 was performed to establish new design limits to accommodate trends toward higher peaking factors. For the analysis of the rod ejection event, it was determined that the use of ZIRLO cladding results in a small reduction in both the fraction of fuel melting at the hot spot and the fuel peak stored energy when compared with the results for Zircaloy clad fuel (Reference 28). The use of Optimized ZIRLO cladding associated with the 15 x 15 Upgrade fuel design has a negligible effect on the results as compared to ZIRLO cladding (Reference 43). The analysis described below is therefore applicable for all of these clad materials.

A rod ejection analysis was performed to establish design limits for the moderator temperature coefficient. A subsequent rod ejection analysis was performed to support the implementation of Integral Fuel Burnable Absorber (IFBA) fuel. The implementation of IFBA fuel core loading patterns at Surry resulted in several core physics parameters exceeding values previously analyzed. The current analysis employs increased key core physics parameter inputs which accommodate the predicted core behavior for IFBA core reload patterns. The current analysis is applicable for both IFBA and non-IFBA fuel types at Surry and is bounding for the 15 x 15 Upgrade fuel design. Also, consistent with the PAD5 fuel performance code, WCAP-17642-P-A, Rev. 1, (Reference 30), the effects of fuel thermal conductivity degradation with burn up are accounted for in the current analysis.

The analysis of the RCCA ejection accident is performed in two stages: first, an average core nuclear power transient calculation, and then a hot-spot heat transfer calculation. The average core power calculation is performed using point neutron kinetics methods to determine the average power generation with time, including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core power generation by the hot-channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is conservatively assumed to persist throughout the transient.

A detailed discussion of the method of analysis can be found in Reference 25.

14.3.3.2.1.1 Average Core Analysis. The point kinetics model of the RETRAN computer code (References 12 and 25) is used to perform the average core transient analysis. This code includes the simulation of prompt and delayed neutrons (using the six group model), the thermal kinetics of the fuel and moderator and the balance of the NSS primary and secondary coolant system. Thermal feedback effects are modeled via temperature dependent reactivity coefficients with a detailed multiregion, transient fuel-clad-coolant heat transfer model. Reactivity insertion from the ejection of the control rod and the subsequent reactor trip are accounted for.

Since both the axial and radial dimensions are missing, it is necessary to use very conservative methods (described below) of calculating the ejected-rod worth and hot-channel factor.

14.3.3.2.1.2 Hot-Spot Analysis. The average core energy addition, calculated as described above, is multiplied by the appropriate hot-channel factors, and the hot-spot analysis is performed using a detailed fuel and clad transient heat transfer model of the RETRAN code termed the Hot Spot Model (Reference 25). This model calculates the transient temperature distribution in a cross section of a metal-clad UO_2 fuel rod and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power generation is used within the fuel rod.

The RETRAN Hot-Spot Model uses the Thom subcooled boiling correlation to determine the film heat transfer before departure from nucleate boiling, and the Bishop-Sandberg-Tong correlation (Reference 23) to determine the film-boiling coefficient after departure from nucleate boiling. The DNB heat flux is not calculated; instead, the code is forced into departure from nucleate boiling by specifying a conservative DNB heat flux. The gap heat transfer coefficient is adjusted to force the full-power steady-state temperature distribution to agree with that predicted by design fuel heat transfer codes presently used by Westinghouse.

For full-power cases, the design initial hot-channel factor (Fqt) is input to the code. The hot-channel factor during the transient is assumed to increase from the steady-state design value to the maximum transient value in 0.1 second and remain at the maximum for the duration of the transient. This is conservative, since detailed spatial kinetics models show that the hot-channel factor decreases shortly after the nuclear power peak due to the power flattening caused by the preferential feedback in the hot channel (Reference 10).

14.3.3.2.1.3 System Overpressure Analysis. Because safety limits for the fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot-spot heat flux versus time. Using these heat flux data, a THINC calculation is conducted to determine the volume surge. Finally, the volume surge is simulated in a plant transient computer code. This code calculates the pressure transient, taking into account fluid transport in the system, heat transfer to the steam generators, and the action of the pressurizer spray and pressure relief valves. No credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing (Reference 10).

Due to the very conservative method of analysis, the peak surge rate is high enough to cause the reactor coolant pressure to exceed the pressurizer safety valve actuation pressure. However, this condition exists only for a few seconds; consequently, the pressurizer water volume does not change significantly (less than 150 ft^3). Therefore, the transient is not sensitive to the initial pressurizer level, and the programmed value is used.

14.3.3.2.2 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The more important parameters are discussed below. Table 14.3-6 presents the parameters used in this analysis. The MUR uprate does not impact 0% power initial condition case results and is bounded by analysis at 102% of 2546 MWt or 100.38% of 2587 MWt initial core power.

14.3.3.2.2.1 Ejected-Rod Worths and Hot-Channel Factors. The values for ejected-rod worths and hot-channel factors are calculated using a synthesis of one-dimensional, two-dimensional and three-dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux-flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculations.

The total transient hot-channel factor, Fqt, is then obtained by combining the axial and radial factors.

Appropriate margins are added to the results to allow for calculational uncertainties, including an allowance for nuclear power peaking due to fuel densification.

14.3.3.2.2.2 Reactivity Feedback Weighting Factors. The largest temperature rises, and hence the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple single-channel analysis. Physics calculations were carried out for a large number of radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers that, when applied to single-channel feedbacks, correct them to effective whole-core feedbacks for the appropriate flux shape. In this analysis, although a point kinetics method is used, only a radial weighting factor is applied. In addition, no weighting is applied to the moderator feedback. This very conservative radial weighting factor is applied to the Doppler reactivity feedback of the fuel as a function of the post-ejection radial power peaking factor to account for the missing spatial effect. This weighting factor has been shown to be conservative compared to three-dimensional analysis (Reference 25).

14.3.3.2.2.3 Moderator and Doppler Coefficient. The critical boron concentration at the beginning of cycle (BOC) and end of cycle (EOC) were adjusted in the nuclear code to obtain moderator density coefficient curves that are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to this coefficient.

The Doppler reactivity coefficeint is determined as a function of fuel temperature using a two-dimensional steady-state computer code with a Doppler weighting factor of 1.0. The resulting coefficient is conservative compared to design predictions for this plant. The weighting factor will increase under accident conditions as discussed above. The transient weighting factor used in the analysis is presented in Table 14.3-6.

14.3.3.2.2.4 Delayed Neutron Fraction, Beff. The accident is sensitive to Beff if the ejected-rod worth is nearly equal to or greater than Beff, as in zero-power transients. To allow for future fuel cycles, conservative estimates of Beff of 0.54% at beginning of cycle and 0.43% at end of cycle were used in the analysis.

14.3.3.2.2.5 Trip Reactivity Insertion. The trip reactivity insertion is assumed to be 4% from 102% of 2546 MWt or 100.38% of 2587 MWt and 1.77% from hot zero power, including the effect of one stuck rod, (i.e., the ejected rod). The shutdown reactivity is simulated by a conservative curve of trip reactivity insertion versus time after trip. The start of the rod motion occurs 0.5 second after the high-neutron-flux point is reached. This delay is assumed to consist of 0.2 second for the instrument channel to produce a signal, 0.15 second for the trip breaker to open, and 0.15 second for the coil to release the rods. The analyses presented are applicable for a rod insertion time of 2.4 second from coil release to entrance of the rod at the dash pot, although measurements indicate that this value should be closer to 1.8 second. The choice of such a conservative insertion rate means that there is over 1 second after the trip point is reached before significant shutdown reactivity is inserted into the core. This is a particularly significant conservatism for hot full-power accidents.

14.3.3.2.3 Results

The value of parameters used in the analysis, as well as the results of the most recent analysis are presented in Table 14.3-6 and discussed below.

14.3.3.2.3.1 Beginning of Cycle, Full Power. Control bank D was assumed to be inserted to its insertion limit. The ejected-rod worth, hot-channel factor, maximum fuel pellet average temperature, maximum fuel center temperature, maximum clad temperature, maximum fuel stored energy and percent of fuel melt are presented in Table 14.3-6.

14.3.3.2.3.2 Beginning of Cycle, Zero Power. For this condition, control bank D was assumed to be fully inserted and control bank C was at its insertion limit. The ejected-rod worth, hot-channel factor, maximum fuel pellet average temperature, maximum fuel center temperature, maximum clad temperature, maximum fuel stored energy and percent of fuel melt are presented in Table 14.3-6.

14.3.3.2.3.3 End of Cycle, Full Power. Control bank D was assumed to be inserted to its insertion limit. The ejected-rod worth, hot-channel factor, maximum fuel pellet average temperature, maximum fuel center temperature, maximum clad temperature, maximum fuel stored energy and percent of fuel melt are presented in Table 14.3-6.

14.3.3.2.3.4 End of Cycle, Zero Power. For this condition, control bank D was assumed to be fully inserted and control bank C was at its insertion limit. The ejected-rod worth, hot-channel factor, maximum fuel pellet average temperature, maximum fuel center temperature, maximum clad temperature, maximum fuel stored energy and percent of fuel melt are presented in Table 14.3-6.

A summary of the cases presented above is given in Table 14.3-6. The nuclear power and hot-spot fuel and clad temperature transients for the EOC full-power and zero-power cases are presented in Figures 14.3-24 through 14.3-27.

14.3.3.2.3.5 Fission Product Release. It is assumed that fission products are released from the gaps of all fuel rods entering DNB. Fission product release fractions, which show the expected fraction of the core inventory that is released to the gap, are summarized in Appendix 14A. These fractions are based on the steady-state fuel temperatures expected at full-power operation, and they include the effect of high fuel temperatures at the hot spot, using the design hot-channel factor. As a result of the rod ejection accident, the hot-spot fuel temperatures will increase, leading to an increase in the fraction of activity released to the gap. However, the results of the rod ejection analysis showed that even at the hot spot there is limited metal-water reaction and the clad is not expected to fail. Even if the rods entering DNB were to fail, only a small portion of the core is affected because of the strong localized peak typical of rod ejection accidents. For example, a fuel census performed from the results of a static, three-dimensional ejected-rod calculation (Figure 14.3-28) shows that, for this typical case, 90% of the fuel volume is operating at a power level less than half that at the hot spot. For this reason, less than 10% of the core enters DNB and a much smaller fraction will experience a fuel temperature nearly as high as that of the hot spot. Since there will be no massive failure of the fuel rods, the position with regard to fission product release, even taking into account the increased fuel temperatures in the area of the rod ejection, is that less than 10% of the core will release fission products. A gap-type release is expected. However, even assuming that a TID-14844-type release (100% of the noble gases and 50% of the halogens) occurs in less than 10% of the core, this release is much less than that for the double-ended severance of a reactor coolant pipe, in which 100% of the total core noble gases and 50% of the total core halogens are assumed to be released.

14.3.3.2.3.6 Pressure Surge. It is shown that there is no danger of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant. The most severe excess addition of energy to the coolant occurs for the high-power and end-of-life case. In order to estimate the magnitude of this pressure transient, average channel and hot-spot heat transfer calculations were performed using a high gap conductance and without assuming DNB. The power curves used for these calculations represented a limiting case in which center melting was initiated at the hot spot. Using these heat flux data, a THINC 3 run was conducted to determine the volume surge without the benefit of pressure feedback. This volume surge was subsequently used as the basis-for a pressure calculation. The results indicated that, starting at 2250 psia, a peak pressure of about 2340 psia occurs some 1.5 seconds after a control-rod assembly ejection.

14.3.3.2.3.7 Lattice Deformation. A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods any produce a force tending to bow the midpoint of the rods toward the hot spot. Physics calculations indicate that the net result of this would be a negative reactivity insertion. In practice, no significant bowing is anticipated, since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot-spot region would produce a net flow away from that region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that cross flow will be sufficient to produce significant lattice forces. Even if massive and rapid boiling, sufficient to distort the lattice, is hypothetically postulated, the large void fraction in the hot-spot region would produce a reduction in the total core moderator-to-fuel ratio and a large reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

14.3.3.3 **Conclusions**

Even on a pessimistic basis, the analyses indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the primary loop. The analyses have demonstrated that the upper limit in fission product release as a result of a number of fuel rods entering departure from nucleate boiling amounts to 10%.

14.3 REFERENCES

1. M. A. Styrikovich et al., *Transfer of Iodine from Aqueous Solutions to Saturated Vapor, Atommaya Energiya*, Vol. 17, No. 1, pp. 45-49, 1964.
2. L. S. Tong, *Boiling Heat Transfer and Two Phase Flow.*
3. Moody, F. J. *Maximum Flow Rate of a Single Component, Two-Phase Mixture,* Journal of Heat Transfer, 93 pp. 179-187, 1965.

4. Letter from W. L. Stewart (VEPCO), to H. R. Denton (NRC), Subject: Supplement 2 to a Request for an Amendment to Operating Licenses DPR-32 and DPR-37, Proposed Reduction in Boron Concentrations, Surry Power Station Units 1 and 2, dated December 19, 1983 (Serial No. 706).

5. Letter from W. L. Stewart (VEPCO) to H. R. Denton (NRC), Subject: Supplement to a Request for an Amendment to Operating Licenses DPR-32 and DPR-37, Proposed reduction in Boron Concentrations, Surry Power Station Units 1 and 2, dated November 30, 1983 (Serial No. 521B).

6. R. J. French et al., Indian Point Unit No. 2 Rod Ejection Analysis, WCAP-2940, 1966.

7. Federal Guidance Report No. 11, *Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion,* EPA 520/1-88-020, U.S. Environmental Protection Agency, 1988.

8. R. F. Barry, *The Revised LEOPARD Code - A Spectrum Dependent Non-Spatial Depletion Program, WCAP-2759*, 1965.

9. Letter from C. M. Stallings, Vepco, to E. G. Case, NRC, Subject: Surry 1 - Cycle 5 Reanalyses, dated March 15, 1978 (Serial No. 108).

10. Westinghouse Electric Corporation, *An Evaluation of the Rod Ejection Accident in Westinghouse PWRs Using; Spatial Kinetics Methods. WCAP-7588*, Rev. 1-A, 1975.

11. F. W. Sliz & K. L. Basehore, *VEPCO Reactor Core Thermal-Hydraulic Analysis Using the COBRA III C/MIT Computer Codes,* VEP-FRD-33A, October 1983.

12. *VEPCO Reactor System Transient Analysis Using RETRAN Computer Code*, VEP-FRD-41, Rev. 0.2-A, March 2015.

13. T. W. T. Burnett, *Reactor Protection System Diversity in Westinghouse Pressurized Water Reactor*, WCAP-7306, April 1969.

14. T. G. Taxelius, ed., *Annual Report - Spert Project. October 1968 and September 1969,* Idaho Nuclear Corporation IN-1370, June 1970.

15. R. C. Liimatainen and F. J. Testa, *Studies in TREAT of Zircaloy-2-Clad, UO^2-Core Simulated Fuel Elements,* ANL-7225, January-June 1966, p. 177, November 1966.

16. Letter from C. M. Stallings (VEPCO) to R. A. Purple (NRC), Serial No. 460, dated March 26, 1975, updating Letter from C. M. Stallings (VEPCO) to K. R. Goller (NRC), Serial No. 369, dated December 18, 1974.

17. Letter from C. M. Stallings (VEPCO) to K. R. Goller (NRC), Subject: Surry 2, Cycle 2 Reload Reanalysis, dated March 12, 1975 (Serial No. 458).

18. Letter from C. M. Stallings (VEPCO} to S. R. Goller (NRC), Subject: Positive Moderator Reanalysis, dated June 5, 1975, (Serial No. 553).

19. Letter from C. M. Stallings (VEPCO) to K. R. Goller (NRC), Subject: Surry 1, Cycle 3 Reload Reanalysis, dated September 8, 1975 (Serial No. 686).

20. Letter from C. M. Stallings (VEPCO) to B. C. Rusche (NRC), Subject: Surry 2, Cycle 3 Reload Reanalysis, dated March 11, 1976 (Serial No. 936).

21. Letter from W. L. Stewart, VEPCO, to U.S. Nuclear Regulatory Commission, Subject: Proposed Technical Specifications Change Surry Improved Fuel Assembly, dated May 26, 1987 (Serial No. 87-188).

22. J. A. Redfield, *CHIC-KIN - A FORTRAN Program for Intermediate and Fast Transients in a Water Moderated Reactor*, WAPD-TM-479, 1965.

23. A. A. Bishop, R. O. Sandberg, and L. S. Tong, *Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux,* ASME 65-HT-31, August 1965.

24. Westinghouse Electric Corporation, *Fuel Densification, Surry Units 1 and 2, Low Pressure Analysis*, WCAP-8117, 1973.

25. J. G. Miller and J. O. Erb, *Vepco Evaluation of the Control Rod Ejection Transient*, VEP-NFE-2-A, December 1984 and letter from C. O. Thomas (NRC) to W. L. Stewart (Vepco) dated September 26, 1984 Re: Acceptance for Referencing of License.

26. Letter from Chandu P. Patel, NRC, to W. L. Stewart, VEPCO, Subject: Issuance of Amendments (TAC Nos. 66359 and 66360), dated November 17, 1987.

27. P. J. Larouere, *Reanalysis of Surry Power Station UFSAR Chapter 14 Rod Ejection Transient,* Technical Report NE-635, May 1988.

28. S. L. Davidson (Ed.) et al, *VANTAGE+ Fuel Assembly Reference Core Report*, WCAP-12610-P-A (Proprietary), April 1995.

29. RADTRAD-NAI Release Version 1.2(QA), Zachry Nuclear Engineering, Inc. Richland, Washington.

30. O. Linsuain, et al., *Westinghouse Performance Analysis and Design Model (PAD5)*, WCAP-17642-P-A, Revision 1 (Proprietary), November 2017.

31. Deleted

32. U.S. Nuclear Regulatory Commission, Office of Nuclear Research, Regulatory Guide 1.183, *Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,* July 2000.

33. Deleted

34. U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, Regulatory Guide 1.194, *Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants*, June 2003.

35. U.S. Nuclear Regulatory Commission, Office of Standards Development, *Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants*, Regulatory Guide 1.52, Revision 2, March 1978.

36. Letter from W. L. Stewart (Virginia Power) to U.S. Nuclear Regulatory Commission, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Control Room Habitability, Operator Dose Assessment*, Serial Number 89-381, June 1989.

37. Letter from C. M. Stalling (Virginia Power) to U.S. Nuclear Regulatory Commission, *Response to Request for Additional Information*, Serial Number 045A/020177, May 1977.

38. Letter from D. S. Cruden (Virginia Power) to NRC, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Safety Evaluation of Steam Generator Tube Rupture Accidents*, Serial No. 88-229, May 5, 1988.

39. Letter from L. A. Walsh (Westinghouse Owner's Group Steam Generator Tube Uncovery Task Team) to R. C. Jones, NRC, *Westinghouse Owner's Group Steam Generator Tube Uncovery Issue*, OG-92-25, March 31, 1992.

40. WCAP-13132, *The Effect of Steam Generator Tube Bundle Uncovery on Radioiodine Release*, January 1992.

41. Federal Guidance Report No. 12, *External Exposures to Radionuclides in Air, Water and Soil,* EPA 420-R-93-081, U.S. Environmental Protection Agency, 1993.

42. DOM-NAF-2-A, *Reactor Core Thermal-Hydraulics Using the VIPRE-D Computer Code*.

43. H. H. Shah and P. Schueren, *Optimized ZIRLO™,* WCAP-12610-P-A and CENPD-404-P-A, Addendum 1-A, July 2006.

Table 14.3-1
TIME SEQUENCE OF EVENTS FOR MAJOR SECONDARY STEAM PIPE RUPTURE
1.4 FT^2 BREAK WITH OFFSITE POWER

Event	Time, sec
Steamline rupture	1.01
High Steamline ΔP	1.16
High Steam Flow	1.58
Pressurizer Empties	11.80
Lo-Lo T_{avg}	13.86
Main Feedwater Isolation	15.07
Safety Injection Initiation	15.87
Main Steamline Isolation	18.86
Critically Reached	29.80
Boron Enters Core	243.6
Peak Heat Flux Reached	244.8

Table 14.3-2

TIME SEQUENCE OF EVENTS FOR MAJOR SECONDARY STEAM PIPE RUPTURE

1.4 FT^2 BREAK WITHOUT OFFSITE POWER

Event	Time, sec
Steamline rupture	1.01
High Steamline ΔP	1.16
High Steam Flow	1.58
Pressurizer Empties	13.80
Main Feedwater Isolation	14.96
Lo-Lo T_{avg}	16.86
Lo Steamline Pressure	19.18
Main Steamline Isolation	21.86
Safety Injection Initiation	25.08
Critically Reached	45.0
Boron Enters Core	253.6
Peak Heat Flux Reached	267.2

Table 14.3-3
TIME SEQUENCE OF EVENTS FOR MAJOR SECONDARY STEAM PIPE RUPTURE CREDIBLE BREAK

Event	Time, sec
Steamline rupture	1.01
Main Feedwater Isolation	8.96
Pressurizer Empties	26.40
Lo-Lo T_{avg}	31.91
Lo-Lo Pressurizer Pressure	68.79
Safety Injection Initiation	73.79
Critically Reached	207.6
Peak Heat Flux	316.8
Boron Enters Core	328.8

Table 14.3-4
SURRY MAIN STEAMLINE BREAK ANALYSIS
1.4 FT^2 BREAK WITH OFFSITE POWER AND CREDIBLE BREAK CASE

Statepoint		1	2	3	4	5 [a]
Time, sec		86.0	174.0	244.8	298.0	316.8
Loop A Cold Leg Temperature, °F		400.7	396.88	396.74	395.86	459.02
Loop B Cold Leg Temperature, °F		471.06	466.76	465.42	463.94	482.33
Loop C Cold Leg Temperature, °F		471.59	466.92	465.44	463.94	482.33
Pressurizer Pressure, psia		820.40	842.60	869.81	882.98	1006.93
Volumetric RCS Flow, % nominal		99.68	99.67	99.67	99.67	99.87
Heat Flux,	% of 2546 MWt	18.33	22.61	23.74	21.90	7.07
	% of 2587 MWt	18.04	22.25	23.36	21.55	6.46

a. Credible Break Statepoint

Table 14.3-5
SURRY MAIN STEAMLINE BREAK ANALYSIS
1.4 FT^2 BREAK WITHOUT OFFSITE POWER

Statepoint	6	7	8	9	10
Time, sec	246.0	267.2	338.0	382.0	470.8
Loop A Cold Leg Temperature, °F	291.32	285.48	271.34	265.74	257.31
Loop B Cold Leg Temperature, °F	467.87	466.18	462.68	460.93	457.27
Loop C Cold Leg Temperature, °F	473.47	471.36	466.86	464.63	460.04
Pressurizer Pressure, psia	848.23	852.61	858.85	862.42	881.58
Volumetric RCS Flow, % nominal	6.12	6.08	5.70	5.44	5.22
Heat Flux, % of 2546 MWt	5.69	5.94	5.15	5.01	5.01
% of 2587 MWt	5.60	5.85	5.07	4.93	4.93

Table 14.3-6a
DELETED

Table 14.3-6
CONTROL ROD ASSEMBLY EJECTION DATA

Parameter	Time In Cycle			
	Beginning	Beginning	End	End
Power Level (% of 2587 MWt)	100.38%	0%	100.38%	0%
Ejected Rod Worth, %Δk/k	0.130	0.780	0.130	0.740
Delayed Neutron Fraction, %	0.54	0.54	0.43	0.43
Feedback Reactivity Weighting	1.029	2.533	0.786	2.466
Trip Reactivity, %Δk/k	4.0	1.77	4.0	1.77
Fq Before Rod Ejection	2.508	-	2.508	-
Fq After Rod Ejection	5.0	16.0	4.5	19.5
Number of Operational Pumps	3	2	3	2
Maximum Fuel Pellet Average Temperature, °F	3648	3254	3771	3679
Maximum Fuel Center Temperature, °F	4781	3789	5017	4219
Maximum Clad Temperature, °F	2204	2365	2180	2681
Maximum Fuel Stored Energy, cal/gm	162	136	170	160
Percent Fuel Melting	0	0	0	0

Table 14.3-7
STEAM GENERATOR TUBE RUPTURE BREAK FLOW RATES AND RELEASES
LOSS OF OFFSITE POWER

From Primary Coolant to Intact SG Liquid	8.34 lbm/min

Affected SG Breakflow			
Time (hrs)		Liquid Break Flow RCS to SG Liquid (lbm/min)	Flashed Break RCS to SG Steam (lbm/min)
From	To		
0	0.0222	4970	712
0.0222	0.0508	4807	263
0.0528	0.5	4065	350

Affected SG Releases				
Time (hrs)		SG Liquid to SG Steam[a] (lbm/min)	SG Steam Release to Environment (lbm/min)	TDAFW Steam Release to Environment (lbm/min)
From	To			
0	0.0222	63806	0	0
0.0222	0.0675	8569	8042	527
0.0675	0.5	5111	4584	527

Intact SG Releases		
Time (hrs)		SG Liquid to Steam to the Environment[a] (lbm/min)
From	To	
0	0.0228	0
0.0228	0.0675	8436
0.0675	0.0978	3037
0.0978	0.5	0

Table 14.3-7 (CONTINUED)
STEAM GENERATOR TUBE RUPTURE BREAK FLOW RATES AND RELEASES
LOSS OF OFFSITE POWER

Intact SG Cooldown Releases - Loss of Offsite Power			
Time (hours)	Intact SG Liquid to Steam release rate (lbm/min)[a]	Intact SG Steam to the Environment release rate (lbm/min)	TDAFW exhaust to Environment release rate (lbm/min)
0.5	11272	10745	527
1	5633	5315	318
1.5	3674	3466	208
2	2787	2627	160
2.5	2309	2175	134
3	1907	1907	
3.5	1777	1777	
4	1684	1684	
4.5	1613	1613	
5	1554	1554	
5.5	1502	1502	
6	1459	1459	
10.5	0	0	

a. Partitioning and Moisture Carryover are modeled in the iodine and particulate releases by decreasing these flow rates by 100.

Table 14.3-8
STEAM GENERATOR TUBE RUPTURE BREAK FLOW RATES AND RELEASES
OFFSITE POWER AVAILABLE

From Primary Coolant to Intact SG Liquid	8.34 lbm/min

Affected SG Breakflow			
Time (hrs)		Liquid Break Flow RCS to SG Liquid (lbm/min)	Flashed Break RCS to SG Steam (lbm/min)
From	To		
0	0.0222	4970	712
0.0222	0.0561	5285	107
0.0561	0.5	4518	73

Affected SG Releases				
Time (hrs)		SG Liquid to SG Steam[a] (lbm/min)	SG Steam Release to Environment (lbm/min)	TDAFW Steam Release to Environment (lbm/min)
From	To			
0	0.0203	63806	0	0
0.0203	0.0222	63806	0	527
0.0222	0.0561	10314	9787	527
0.0561	0.5	6545	6018	527

Intact SG Releases		
Time (hrs)		SG Liquid to Steam to the Environment[a] (lbm/min)
From	To	
0	0.0228	0
0.0228	0.0561	11942
0.0508	0.0756	3197
0.0756	0.5	0

Time (hours)	Intact SG Liquid to Steam release rate (lbm/min)[a]	Intact SG Steam to the Environment release rate (lbm/min)	TDAFW exhaust to Environment release rate (lbm/min)
0.5	12698	12170	527
1	6307	5949	358
1.5	4217	3980	238

Table 14.3-8 (CONTINUED)
STEAM GENERATOR TUBE RUPTURE BREAK FLOW RATES AND RELEASES
OFFSITE POWER AVAILABLE

2	3318	3130	188
Intact SG Cooldown Releases - Loss of Offsite Power			
Time (hours)	Intact SG Liquid to Steam release rate (lbm/min)	Intact SG Steam to the Environment release rate (lbm/min)	TDAFW exhaust to Environment release rate (lbm/min)
2.5	2851	2688	163
3	2585	2436	149
3.5	2427	2286	141
4	2323	2189	135
4.5	2249	2118	131
5	2062	2062	0
5.5	2014	2014	
6	1999	1999	
10.5	0	0	

a. Partitioning and Moisture Carryover are modeled in the iodine and particulate releases by decreasing these flow rates by 100.

Table 14.3-9

STEAM GENERATOR TUBE RUPTURE CONTROL ROOM AND OFFSITE DOSES[1]

	Concurrent Iodine Spike (Rem TEDE)	Acceptance Criteria[2] (Rem TEDE)
Control Room	0.3	5
EAB	1.1	2.5
LPZ	0.1	2.5

	Preaccident Iodine Spike (Rem TEDE)	Acceptance Criteria[2] (Rem TEDE)
Control Room	0.7	5
EAB	0.8	25
LPZ	0.1	25

1. The limiting control room dose is based on 0 cfm of unfiltered inleakage and offsite power available. The limiting offsite doses are obtained with a coincident LOOP.
2. RG 1.183 and 10 CFR 50.67

Table 14.3-10
PRIMARY COOLANT RADIONUCLIDE INVENTORY
TECHNICAL SPECIFICATION LIMIT FOR DOSE EQUIVALENT I-131

Nuclide	FGR11 Table 2.1 CEDE DCF 1µCi/gm DE I-131 (µCi/gm)
Kr-83m	1.60E-01
Kr-85m	5.79E-01
Kr-85	2.09E+00
Kr-87	3.86E-01
Kr-88	1.08E+00
Kr-89	3.26E-02
Xe-131m	1.23E+00
Xe-133m	1.51E+00
Xe-133	1.02E+02
Xe-135m	3.90E-01
Xe135	4.09E+00
Xe-137	8.12E-02
Xe-138	2.75E-01
Br-83	2.86E-02
Br-84	1.54E-02
Br-85	1.68E-03
Br-87	8.78E-04
I-129	2.75E-08
I-130	1.16E-02
I-131	7.42E-01
I-132	3.85E-01
I-133	1.25E+00
I-134	2.50E-01

Nuclide	FGR11 Table 2.1 CEDE DCF 1µCi/gm DE I-131 (µCi/gm)
Rh-105	9.76E-05
Rh-106	5.70E-05
Rh-107	4.42E-06
Sn-127	9.15E-07
Sn-128	2.00E-06
Sn-130	3.48E-07
Sb-127	7.79E-06
Sb-128	8.80E-07
Sb-129	1.33E-05
Sb-130	1.09E-06
Sb-131	4.78E-06
Sb-132	3.69E-07
Sb-133	4.42E-07
Te-125m	1.03E-04
Te-127m	8.32E-04
Te-127	3.47E-03
Te-129m	3.62E-03
Te-129	4.59E-03
Te-131m	1.00E-02
Te-131	4.68E-03
Te-132	7.96E-02
Te-133m	7.76E-03
Te-133	3.57E-03

Table 14.3-10 (CONTINUED)
PRIMARY COOLANT RADIONUCLIDE INVENTORY
TECHNICAL SPECIFICATION LIMIT FOR DOSE EQUIVALENT I-131

Nuclide	FGR11 Table 2.1 CEDE DCF 1μCi/gm DE I-131 (μCi/gm)
I-135	8.23E-01
I-136	2.86E-03
Se-81	2.52E-07
Se-83	3.46E-07
Se-84	2.08E-07
Rb-86	1.03E-02
Rb-88	1.12E+00
Rb-89	6.72E-02
Rb-90	5.26E-03
Rb-91	2.62E-03
Rb-92	1.77E-04
Sr-89	9.17E-04
Sr-90	5.67E-05
Sr-91	4.70E-04
Sr-92	3.82E-04
Sr-93	1.94E-05
Sr-94	3.31E-06
Y-90	7.01E-05
Y-91m	2.79E-04
Y91	1.03E-03
Y-92	4.30E-04
Y-92	2.30E-04
Y-93	2.30E-04

Nuclide	FGR11 Table 2.1 CEDE DCF 1μCi/gm DE I-131 (μCi/gm)
Te-134	1.20E-02
Cs-134m	1.47E-02
Cs-134	1.11E+00
Cs-136	3.05E-01
Cs-137	8.24E-01
Cs-138	4.21E-01
Cs-139	3.82E-02
Cs-140	3.88E-03
Cs-142	4.62E-05
Ba-137m	7.72E-01
Ba-139	3.14E-02
Ba-140	1.14E-03
Ba-141	5.07E-05
Ba-142	7.85E-05
La-140	3.16E-04
La-141	9.51E-05
La-142	9.65E-05
La-143	5.92E-06
Ce-141	1.58E-04
Ce-143	1.29E-04
Ce-144	1.22E-04
Ce-144	1.22E-04
Ce-145	8.96E-07

Table 14.3-10 (CONTINUED)
PRIMARY COOLANT RADIONUCLIDE INVENTORY
TECHNICAL SPECIFICATION LIMIT FOR DOSE EQUIVALENT I-131

Nuclide	FGR11 Table 2.1 CEDE DCF 1μCi/gm DE I-131 (μCi/gm)
Y-94	1.19E-05
Y-95	4.93E-06
Zr-95	1.62E-04
Zr-97	1.17E-04
Nb-95m	1.82E-06
Nb-95	1.64E-04
Nb-97m	1.10E-04
Nb-97	1.23E-04
Mo-99	1.09E+00
Mo-101	8.75E-03
Mo-102	6.31E-03
Mo-105	2.93E-04
Tc-99m	4.69E-01
Tc-101	8.39E-03
Tc-102	6.31E-03
Tc-105	3.08E-04
Ru-103	1.48E-04
Ru-105	4.63E-05
Ru-106	5.11E-05
Ru-107	7.57E-07
Rh-103m	1.49E-04
Rh-105m	1.32E-05

Nuclide	FGR11 Table 2.1 CEDE DCF 1μCi/gm DE I-131 (μCi/gm)
Ce-146	3.25E-06
Pr-143	1.49E-04
Pr-144	1.23E-04
Pr-145	5.27E-05
Pr-146	8.47E-06
Nd-147	6.24E-05
Nd-149	8.62E-06
Nd-151	6.72E-07
Pm-147	2.96E-05
Pm-149	5.21E-05
Pm-151	1.61E-05
Sm-151	1.62E-07
Na-24	1.41E-01
Cr-51	9.30E-03
Mn-54	4.80E-03
Fe-55	3.60E-03
Fe-59	9.00E-04
Co-58	1.38E-02
Co-60	1.59E-03
Zn-65	1.53E-03
Np-239	6.60E-03
H-3	2.50E+00

Table 14.3-11
PRIMARY COOLANT TECHNICAL SPECIFICATION PRE-ACCIDENT SPIKE AND CONCURRENT IODINE SPIKE ACTIVITIES

Nuclide	10 µCi/gm DE I-131 Pre-Accident Iodine Spike Concentrations (µCi/gm)	SGTR Concurrent Spike (Total Curies over 8 hours)	MSLB Concurrent Spike (Total Curies over 8 hours)
I-131	7.42	6.02E+04	8.96E+04
I-132	3.85	8.32E+04	1.24E+05
I-133	12.5	1.18E+05	1.76E+05
I-134	2.50	1.09E+05	1.62E+05
I-135	8.23	1.04E+05	1.55E+05

Table 14.3-12
VOLUMES USED IN ANALYSIS OF MAIN STEAM LINE BREAK (MSLB), AND STEAM GENERATOR TUBE RUPTURE (SGTR)

Description	MSLB	SGTR
RCS Mass	406,300 lbm	406,300 lbm
ASG Liquid Mass	154,490 lbm	93,261 lbm
ISG Liquid Mass per Generator	93,261 lbm	93,261 lbm
Turbine Building Volume	3.0E+06 ft^3	-
ASG Steam Mass	-	6,739 lbm
ISG Steam Mass	-	13,478 lbm
Control Room Volume	223,000 ft^3	223,000 ft^3

Table 14.3-13

χ/Qs USED IN THE SGTR AND MSLB ANALYSES

Location	Time (hours)	SGTR χ/Q (sec/m^3)	MSLB χ/Q (sec/m^3)
EAB	0-720	9.46E-04	1.19E-03
LPZ	0-8	5.64E-05	5.73E-05
LPZ	8-24	3.83E-05	3.89E-05
LPZ	24-96	1.65E-05	1.68E-05
LPZ	96-720	4.92E-06	5.05E-06

Location	Time (hours)	Normal Intake χ/Q[a] (sec/m^3)	Emergency Intake χ/Q (sec/m^3)
Control Room from PORVs and Safety Valves	0-2	1.98E-03	5.72E-04
	2-8	1.45E-03	4.58E-04
	8-24	6.42E-04	1.78E-04
	24-96	4.08E-04	1.30E-04
	96-720	2.90E-04	9.76E-05
Control Room from PORVs and Safety Valves	0-2	2.86E-03	1.00E-03
	2-8	2.22E-03	7.60E-04
	8-24	8.92E-04	3.04E-04
	24-96	6.58E-04	2.20E-04
	96-720	4.80E-04	1.66E-04

a. The Normal Intake χ/Q is used by the model until the control room is isolated, at which point the model transitions to using the Emergency Intake χ/Q.

Table 14.3-14
MSLB RELEASE RATES

Affected Steam Generator to Turbine Building and Turbine Building Volumetric Flow Rates to Environment

Time [hrs]	Mass Flow Rate to Turbine Building [lbm/min]	Turbine Building Volumetric Flow Rate to Environment, LOOP Conditions [cfm]	Turbine Building Volumetric Flow Rate to Environment, no-LOOP Conditions [cfm]
0.000E+00	0.0	0.000E+00	6.000E+05
2.778E-05	1.979E+05	4.946E+06	5.546E+06
1.389E-04	1.899E+05	4.747E+06	5.347E+06
2.778E-04	1.796e+05	4.491E+06	5.091E+06
3.056E-03	9.515E+04	2.379E+06	2.979E+06
5.833E-04	6.971E+04	1.743E+06	2.343E+06
8.611E-03	5.568E+04	1.392E+06	1.992E+06
1.139E-02	4.855E+04	1.214E+06	1.814E+06
1.417E-02	4.481E+04	1.120E+06	1.720E+06
1.972E-02	4.139E+04	1.035E+06	1.635E+06
2.250E-02	4.056E+04	1.014E+06	1.614E+06
2.528E-02	4.001E+04	1.000E+06	1.600E+06
2.806E-02	3.963E+04	9.907E+05	1.591E+06
4.194E-02	3.873E+04	9.682E+05	1.568E+06
4.750E-02	3.862E+04	9.654E+05	1.565E+06
5.028E-02	3.854E+04	9.636E+05	1.564E+06
5.444E-02	3.852E+04	9.631E+05	1.563E+06
5.583E-02	2.375E+04	5.938E+05	1.194E+06
5.861E-02	1.400E+04	3.500E+05	9.500E+05
6.278E-02	1.257E+04	3.143E+05	9.143E+05
6.417E-02	1.312E+04	3.280E+05	9.280E+05
6.972E-02	1.270E+04	3.175E+05	9.175E+05
8.361E-02	1.239E+04	3.099E+05	9.099E+05
1.100E-01	1.248E+04	3.120E+05	9.120E+05
1.114E-01	1.203E+04	3.006E+05	9.006E+05
1.169E-01	1.321E+04	3.302E+05	9.302E+05
1.197E-01	1.219E+04	3.048E+05	9.048E+05
1.253E-01	1.307E+04	3.269E+05	9.269E+05
1.392E-01	1.291E+04	3.227E+05	9.227E+05
1.667E-01	1.302E+04	3.254E+05	9.254E+05
5.000E-01	0	1.000E+04	6.000E+05

Table 14.3-14 (CONTINUED)
MSLB RELEASE RATES

Intact Steam Generators to the Environment - No-LOOP

Time [hrs]	Break Flow [lbm/min]	Time [hrs]	Break Flow [lbm/min]
0	0	3.5	2233
0.00003	396100	4.0	2158
0.00014	378900	4.5	2099
0.00028	358700	5.0	2050
0.00306	0	5.5	2055
0.5	3942	6.0	2048
1.0	3524	6.5	2035
1.5	3308	7.0	2020
2.0	2843	7.5	2002
2.5	2531	8.0	1983
3.0	2346		

TDAFWP to the Environment - No-Loop	
Time[hrs]	Break Flow [lbm/min]
0.0	527
0.5	343
1.0	264
1.5	200
2.0	166
2.5	147
3.0	137
3.5	129
4.0	125
4.5	121
5.0	121
5.5	0

Table 14.3-14a
MSLB RELEASE RATES

ISGs to the Environment - LOOP

Time [hrs]	Steam Mass Release Rate [lbm/min]	Time [hrs]	Steam Mass Release Rate [lbm/min]	Time [hrs]	Steam Mass Release Rate [lbm/min]
0	0	11.5	601	25	969
0.00003	396100	12	795	25.5	1088
0.00014	378900	12.5	807	26	1084
0.00028	358700	13	817	26.5	1079
0.00306	0	13.5	827	27	1074
0.5	2241	14	836	27.5	1071
1	1739	14.5	845	28	1067
1.5	1431	15	853	28.5	1064
2	1249	15.5	861	29	1061
2.5	1127	16	867	29.5	1058
3	1049	16.5	873	30	1056
3.5	1006	17	880	30.5	1029
4	968	17.5	889	31	983
4.5	929	18	897	31.5	950
5	889	18.5	904	32	926
5.5	849	19	911	32.5	909
6	823	19.5	918	33	861
6.5	802	20	924	33.5	857
7	781	20.5	929	34	854
7.5	760	21	935	34.5	850
8	740	21.5	939	35	846
8.5	719	22	943	35.5	843
9	698	22.5	948	36	839
9.5	677	23	952	36.5	835
10	657	23.5	957	37	832
10.5	636	24	962	37.5	828
11	615	24.5	965	38	0

Table 14.3-14b
MSLB RELEASE RATES

TDAFWP to the Environment - LOOP

Time [hrs]	Steam Mass Release Rate [lbm/min]	Time [hrs]	Steam Mass Release Rate [lbm/min]
0	527	18.5	266
11.5	527	19.0	252
12.0	509	19.5	239
12.5	486	20.0	226
13.0	463	20.5	213
13.5	442	21.0	201
14.0	421	21.5	190
14.5	401	22.0	180
15.0	381	22.5	169
15.5	363	23.0	159
16.0	345	23.5	150
16.5	328	24.0	141
17.0	312	24.5	133
17.5	296	25.0	124
18.0	281	25.5	0

Table 14.3-15
MAIN STEAM LINE BREAK CONTROL ROOM AND OFFSITE DOSES

	Concurrent Iodine Spike (Rem TEDE)	Acceptance Criteria[1] (Rem TEDE)
Control Room	1.6	5
EAB	0.6	2.5
LPZ	0.1	2.5

	Preaccident Iodine Spike (Rem TEDE)	Acceptance Criteria (Rem TEDE)
Control Room	1.4	5
EAB	0.4	25
LPZ	0.1	25

1.RG 1.183 and 10 CFR 50.67

Table 14.3-16
FISSION PRODUCT CONCENTRATIONS IN THE REACTOR COOLANT WITH SMALL CLADDING DEFECTS IN ONE PERCENT OF THE FUEL RODS
(2605 MWt, 18 month cycles, 574.4°F)

Isotope	Concentration µCi/gm
Kr-83m	3.30E-0l
Kr-85m	1.20E+00
Kr-85	4.32E+00
Kr-87	7.99E-01
Kr-88	2.24E+00
Kr-89	6.74E-02
Xe-131m	2.55E+00
Xe-133m	3.13E+00
Xe-133	2.10E+02
Xe-135m	8.06E+00
Xe-135	8.46E+00
Xe-137	1.68E-01
Xe-138	5.69E-01
Br-83	5.91E-02
Br-84	3.19E-02
Br-85	3.48E-03
Br-87	1.82E-03
I-129	5.68E-08
I-130	2.41E-02
I-131	1.53E+00
I-132	7.95E-01
I-133	2.58E+00
I-134	5.18E-01
I-135	1.70E+00

Isotope	Concentration µCi/gm
Zr-97	2.41E-04
Nb-95m	3.76E-06
Nb-95	3.39E-04
Nb-97m	2.28E-04
Nb-97	2.55E-04
Mo-99	2.26E+00
Mo-101	1.81E-02
Mo-102	1.31E-02
Mo-105	6.05E-04
Tc-99m	9.70E-01
Tc-101	1.74E-02
Tc-102	1.31E-02
Tc-105	6.37E-04
Ru-103	3.07E-04
Ru-105	9.59E-05
Ru-106	1.06E-04
Ru-107	1.57E-06
Rh-103m	3.084-04
Rh-105m	2.72E-05
Rh-105	2.02E-04
Rh-106	1.18E-04
Rh-107	9.14E-06
Sn-127	1.89E-06
Sn-128	4.13E-06

Isotope	Concentration µCi/gm
Ba-139	6.49E-02
Ba-140	2.35E-03
Ba-141	1.05E-04
Ba-142	1.62E-04
La-140	6.54E-04
La-141	1.97E-04
La-142	2.00E-04
La-143	1.23E-05
Ce-141	3.27E-04
Ce-143	2.66E-04
Ce-144	2.53E-04
Ce-145	1.85E-06
Ce-146	6.72E-06
Pr-143	3.09E-04
Pr-144	2.55E-04
Pr-145	1.09E-04
Pr-146	1.75E-05
Nd-147	1.29E-04
Nd-149	1.78E-05
Nd-151	1.39E-06
Pm-147	6.12E-05
Pm-149	1.08E-04
Pm-151	3.33E-05
Sm-151	3.35E-07

Table 14.3-16 (CONTINUED)
FISSION PRODUCT CONCENTRATIONS IN THE REACTOR COOLANT WITH SMALL CLADDING DEFECTS IN ONE PERCENT OF THE FUEL RODS
(2605 MWt, 18 month cycles, 574.4°F)

Isotope	Concentration μCi/gm
I-136	5.91 E-03
Se-8l	5.21 E-07
Se-83	7.15E-07
Se-84	4.30E-07
Rb-86	2.14E-02
Rb-88	2.33E+00
Rb-89	1.39E-01
Rb-90	1.09E-02
Rb-9l	5.43E-03
Rb-92	3.67E-04
Sr-89	1.90E-03
Sr-90	1.17E-04
Sr-91	9.72E-04
Sr-92	7.90E-04
Sr-93	4.01E-05
Sr-94	6.84E-06
Y-90	1.45E-04
Y-91m	5.76E-04
Y-91	2.13E-03
Y-92	8.90E-04
Y-93	4.76E-04
Y-94	2.47E-05
Y-95	1.02E-05
Zr-95	3.36E-04

Isotope	Concentration μCi/gm
Sn-130	7.20E-07
Sb-127	1.61E-05
Sb-128	1.82E-06
Sb-129	2.75E-05
Sb-130	2.25E-06
Sb-131	9.88E-06
Sb-132	7.63E-07
Sb-133	9.15E-07
Te-125m	2.12E-04
Te-127m	1.72E-03
Te-127	7.17E-03
Te-129m	7.49E-03
Te-129	9.50E-03
Te-131m	2.07E-07
Te-131	9.68E-03
Te-132	1.65E-01
Te-133m	1.61E-02
Te-133	7.38E-03
TE-134	2.49E-02
TE-134m	3.05E-02
Cs-134	2.29E+00
Cs-136	6.31E-01
Cs-137	1.71E00
Cs-138	8.71E-01

Isotope	Concentration μCi/gm
Na-24	1.41E-01
Cr-51	9.30E-03
Mn-54	4.80E-03
Fe-55	3.60E-03
Fe-59	9.00E-04
Co-58	1.38E-02
Co-60	1.59E-03
Zn-65	1.53E-03
NP-239	6.60E-03
H-3	2.50E+00

Table 14.3-16 (CONTINUED)
FISSION PRODUCT CONCENTRATIONS IN THE REACTOR COOLANT WITH SMALL CLADDING DEFECTS IN ONE PERCENT OF THE FUEL RODS
(2605 MWt, 18 month cycles, 574.4°F)

Isotope	Concentration μCi/gm	Isotope	Concentration μCi/gm	Isotope	Concentration μCi/gm
		Cs-139	7.89E-02		
		Cs-140	8.03E-03		
		Cs-142	9.55E-05		
		Ba-137m	1.60E00		

Figure 14.3-1
STEAM GENERATOR TUBE RUPTURE - RCS AVERAGE TEMPERATURE

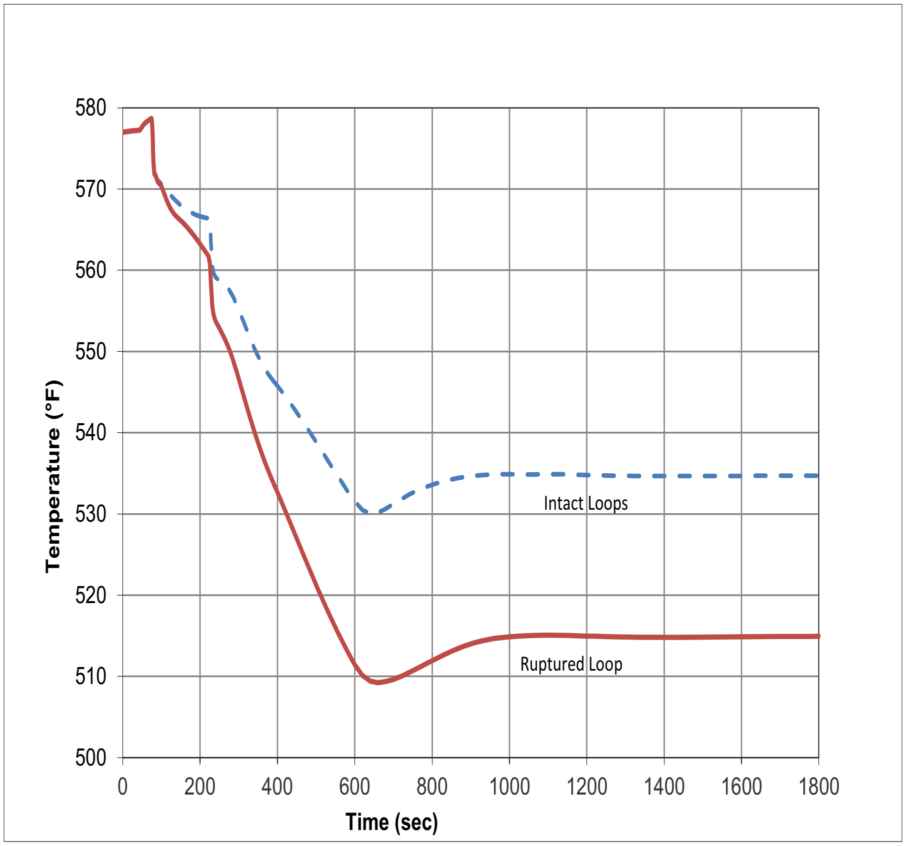


Figure 14.3-2
STEAM GENERATOR TUBE RUPTURE - RUPTURED STEAM GENERATOR PRESSURE

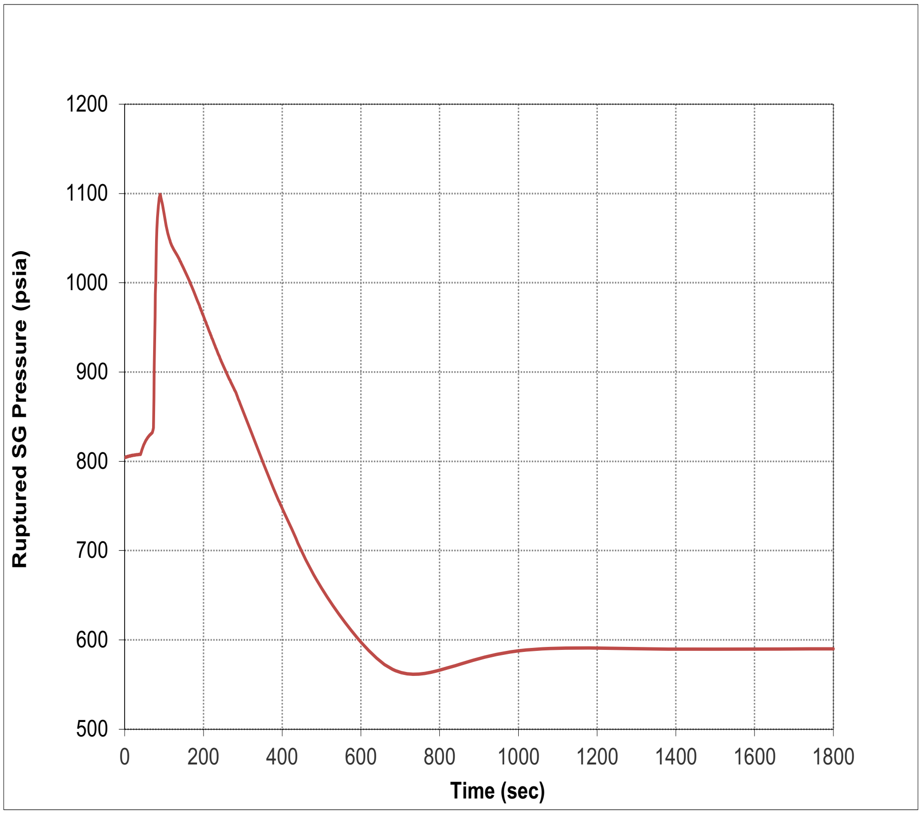


Figure 14.3-3
STEAM GENERATOR TUBE RUPTURE - STEAM GENERATOR PRESSURE

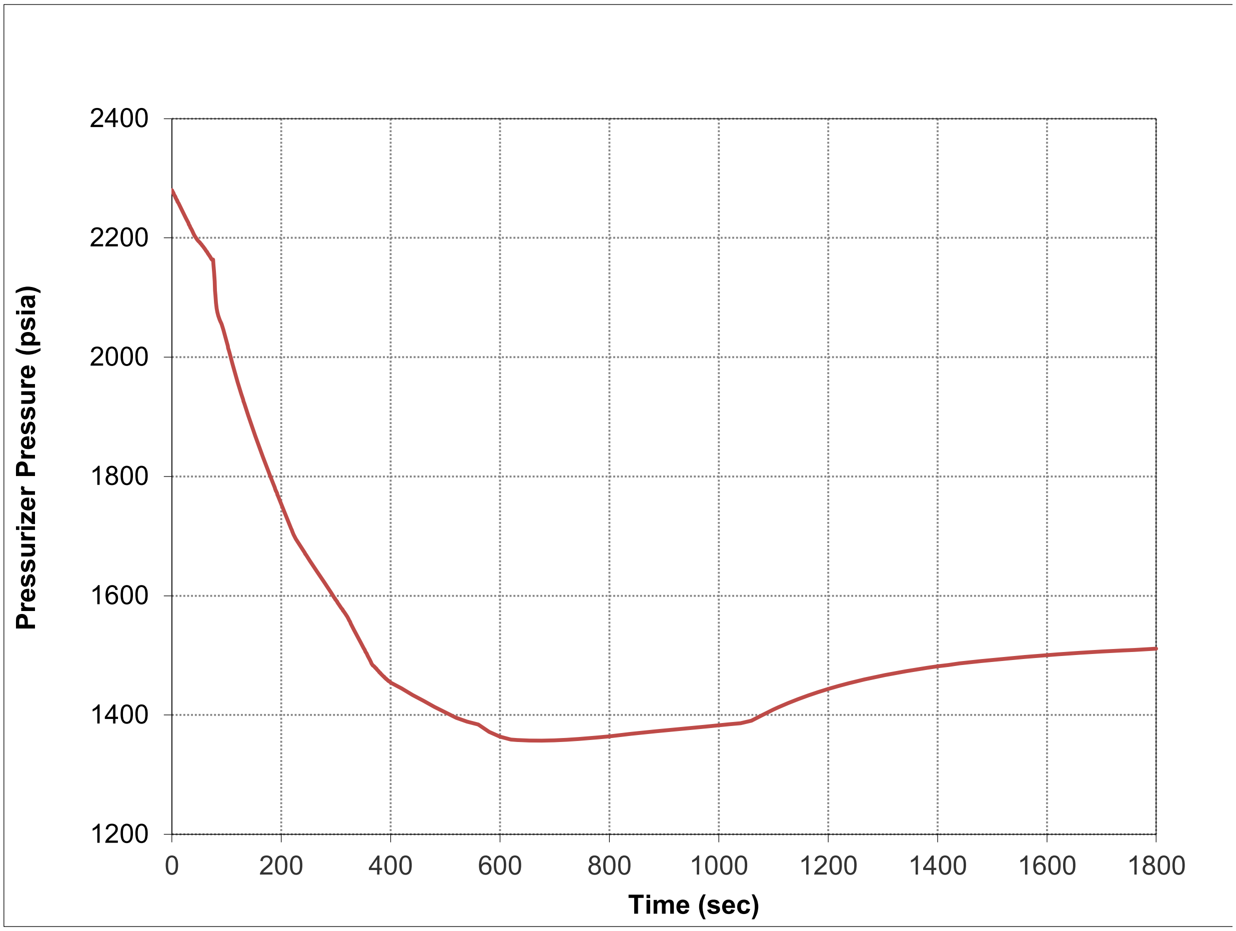


Figure 14.3-4
STEAM GENERATOR TUBE RUPTURE - INTACT STEAM GENERATOR INTEGRATED STEAM RELEASE

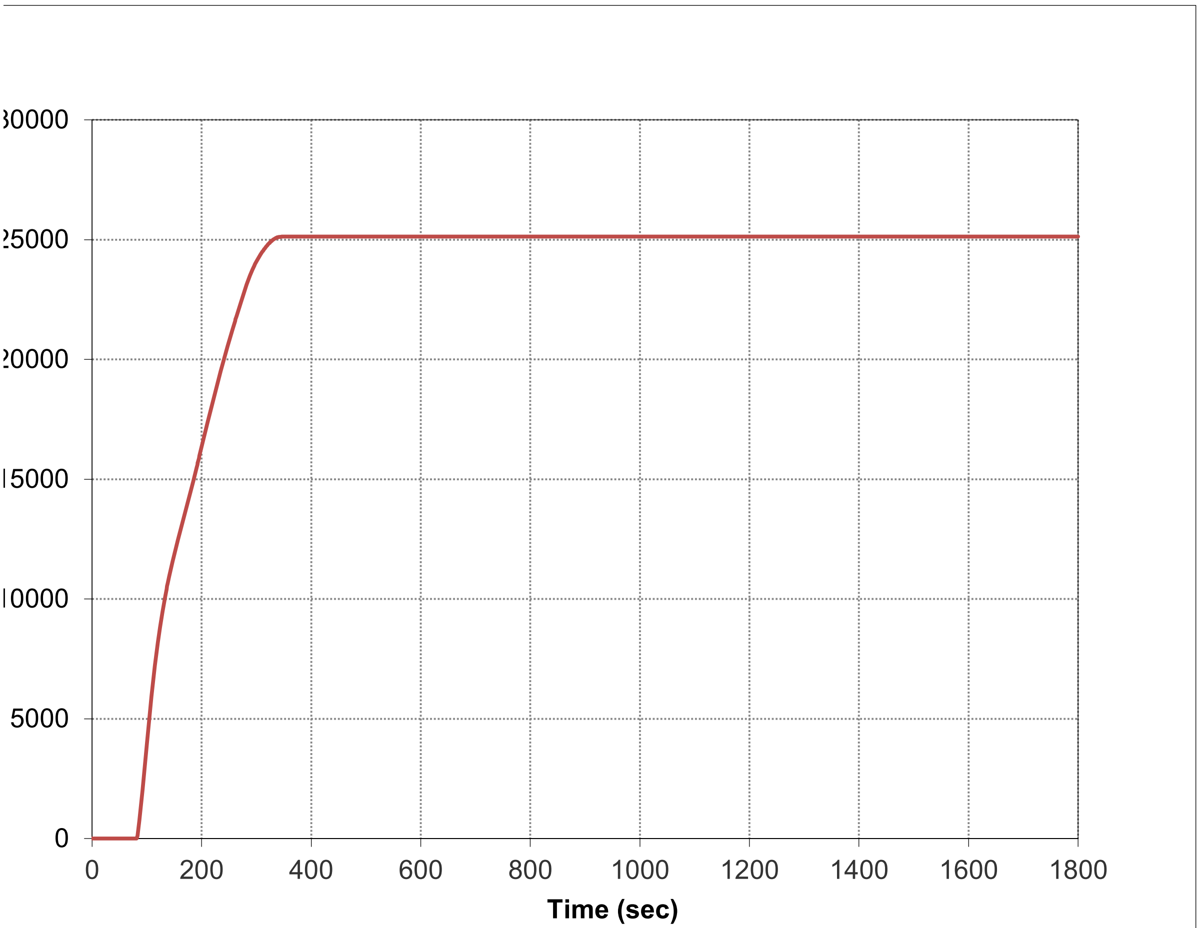


Figure 14.3-5
STEAM GENERATOR TUBE RUPTURE - RUPTURED STEAM GENERATOR
INTEGRATED STEAM RELEASE

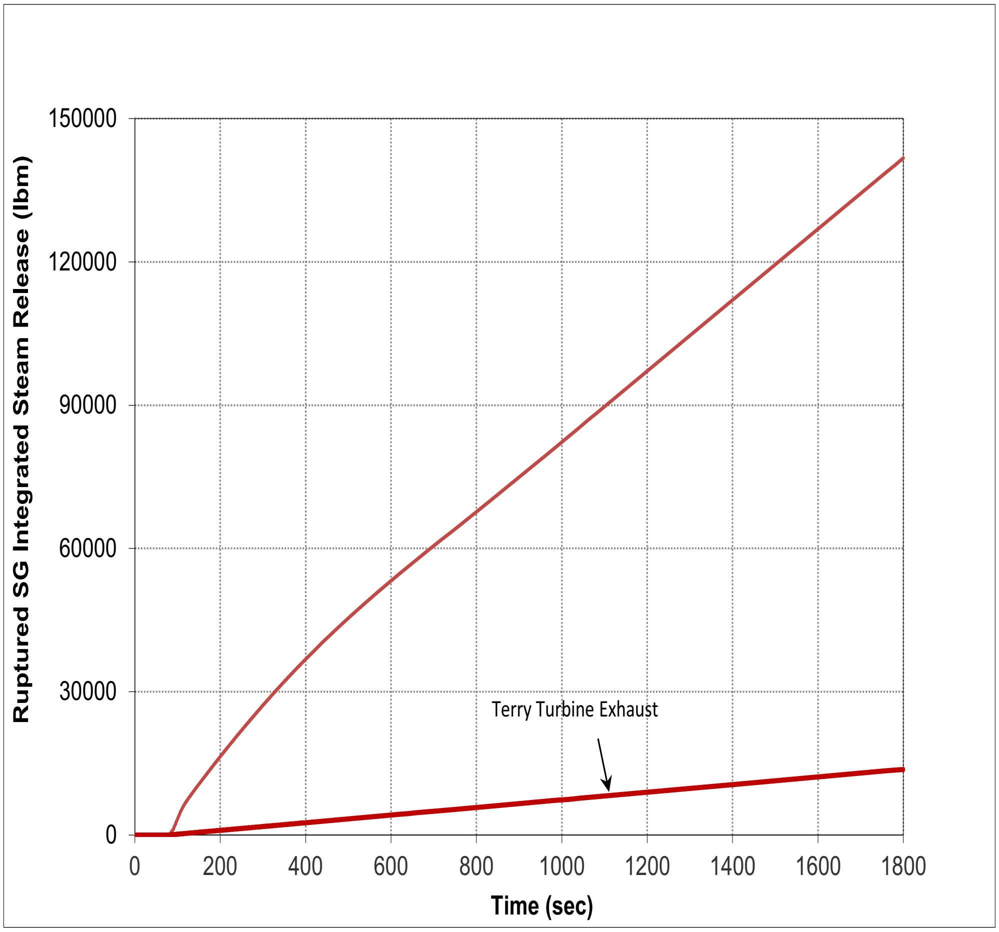


Figure 14.3-6
STEAM GENERATOR TUBE RUPTURE - TOTAL BREAK FLOW

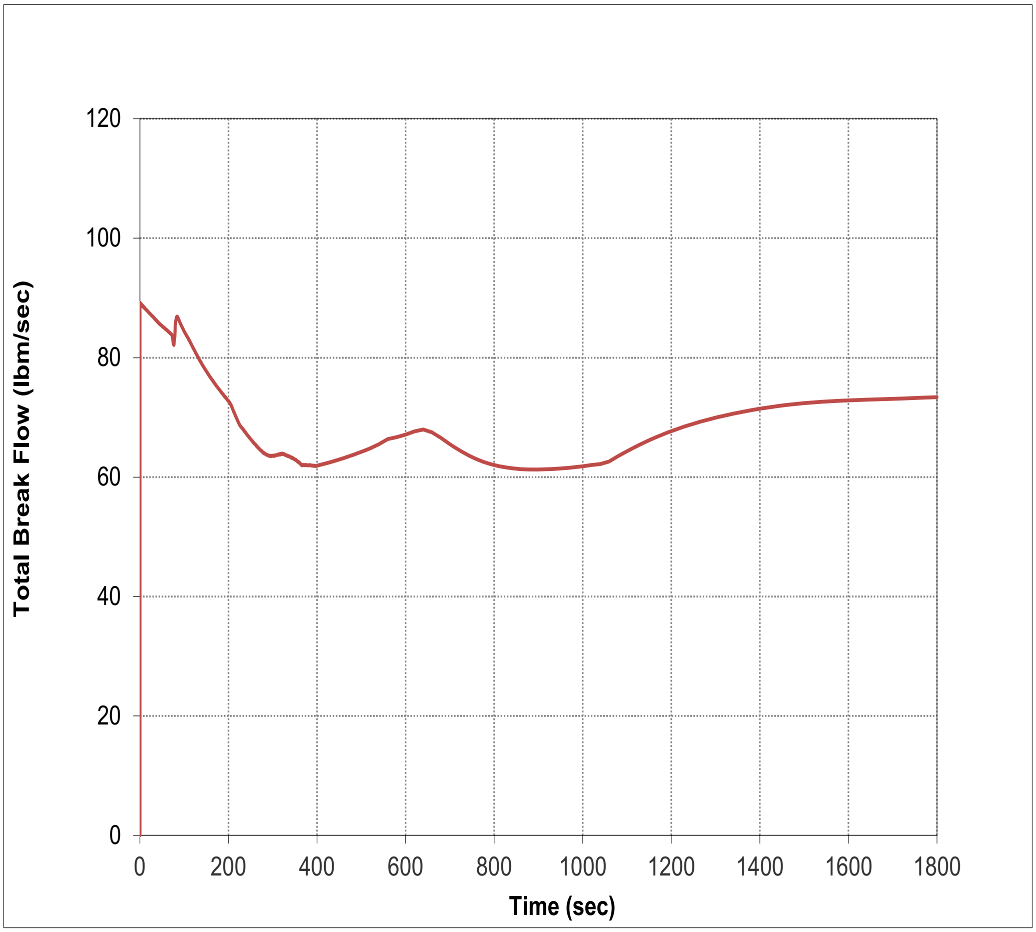


Figure 14.3-7
STEAM GENERATOR TUBE RUPTURE - INTEGRATED BREAK FLOW

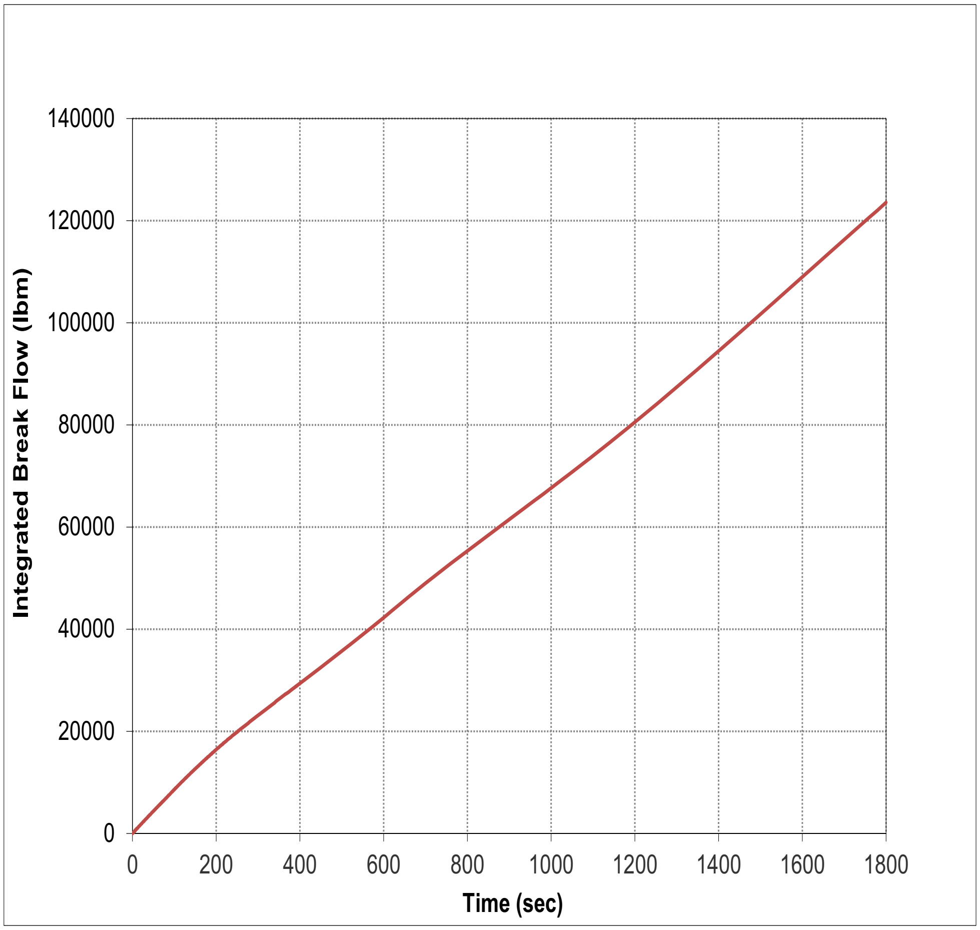


Figure 14.3-8
VARIATION OF REACTIVITY WITH POWER

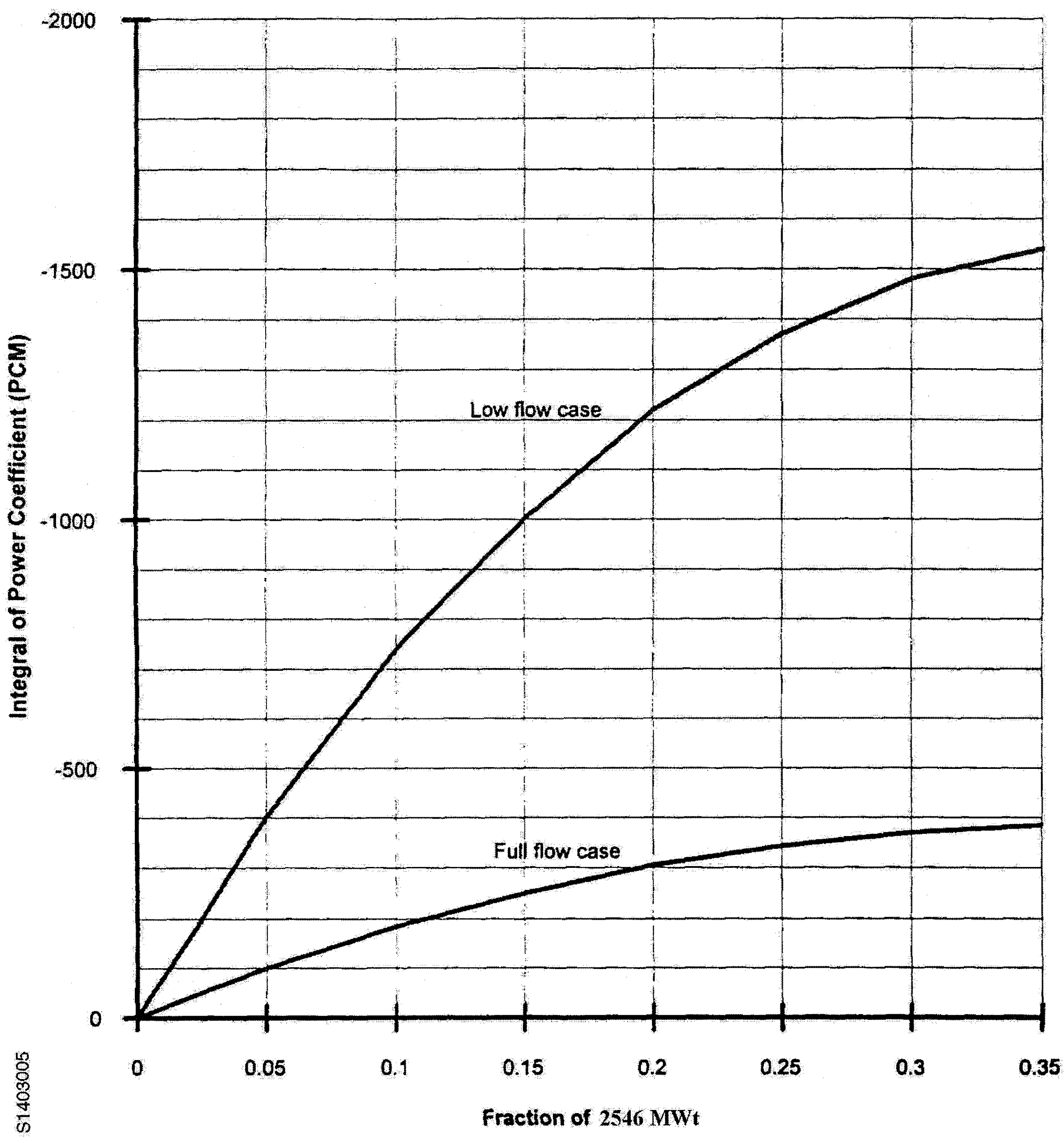


Figure 14.3-9
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK, OFFSITE POWER AVAILABLE NORMALIZED CORE HEAT FLUX (FRACTION OF 2546 MWt)

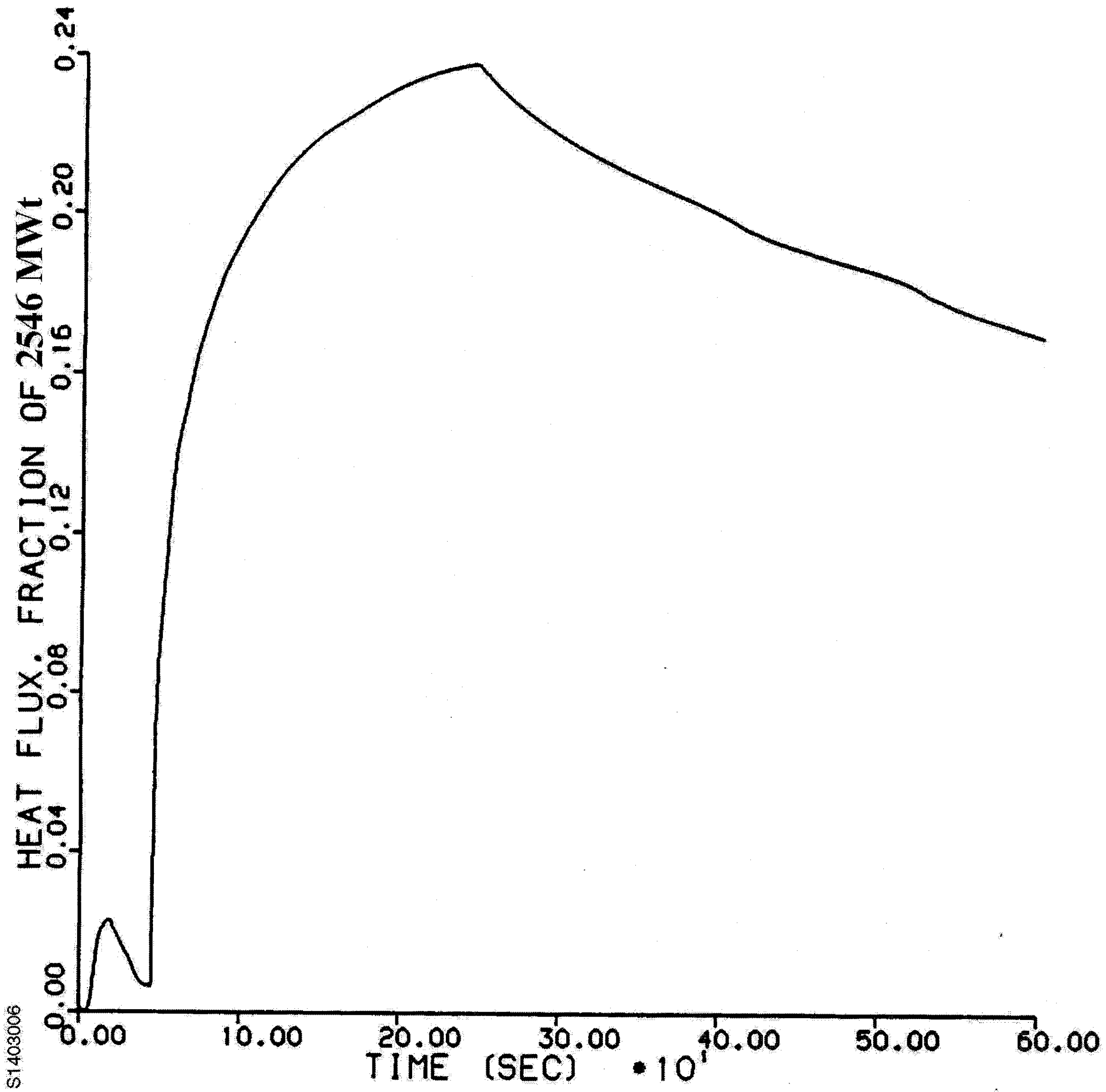


Figure 14.3-10
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
OFFSITE POWER AVAILABLE PRESSURIZER PRESSURE

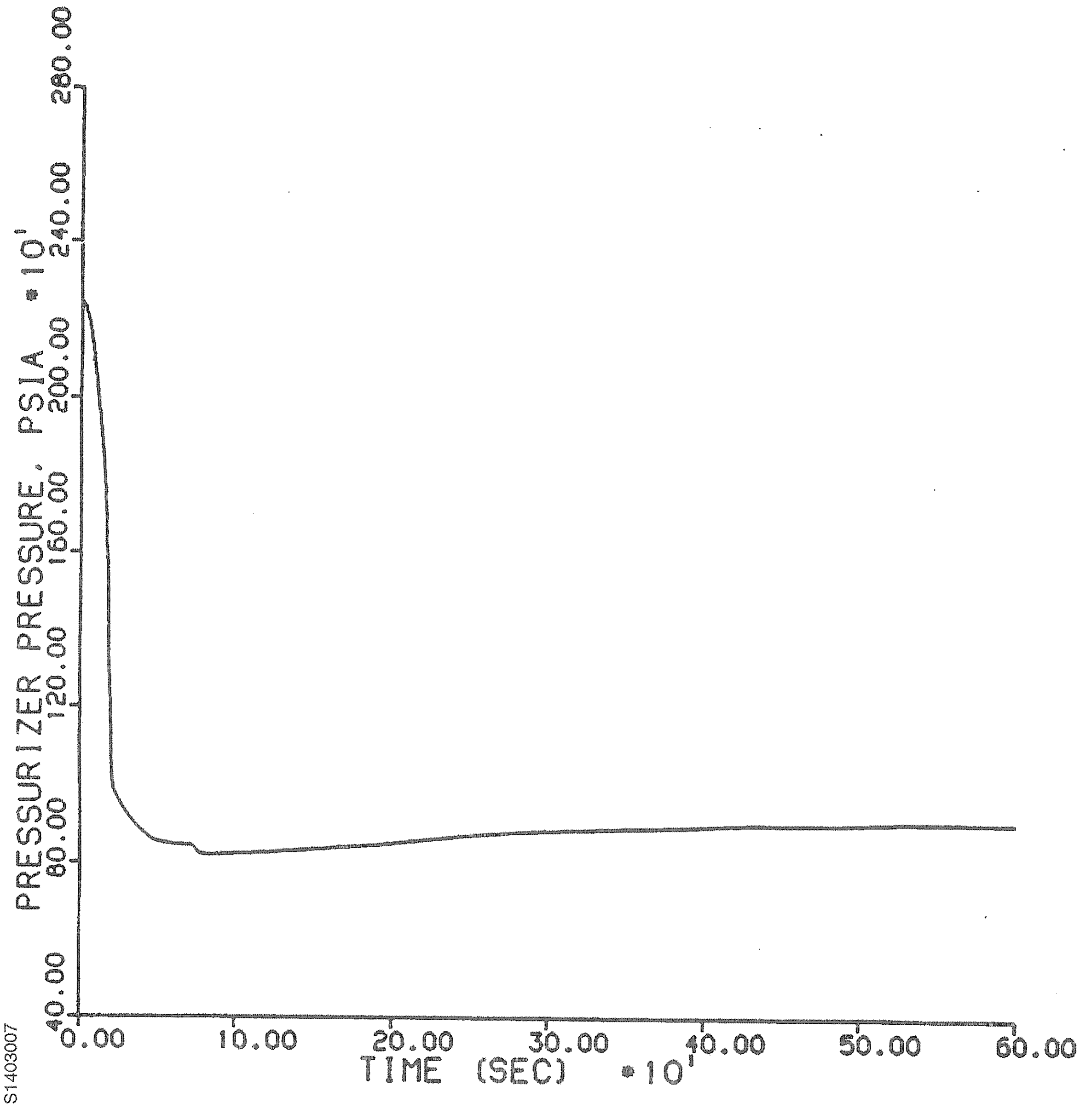


Figure 14.3-11
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
OFFSITE POWER AVAILABLE CORE REACTIVITY,% ΔK/K

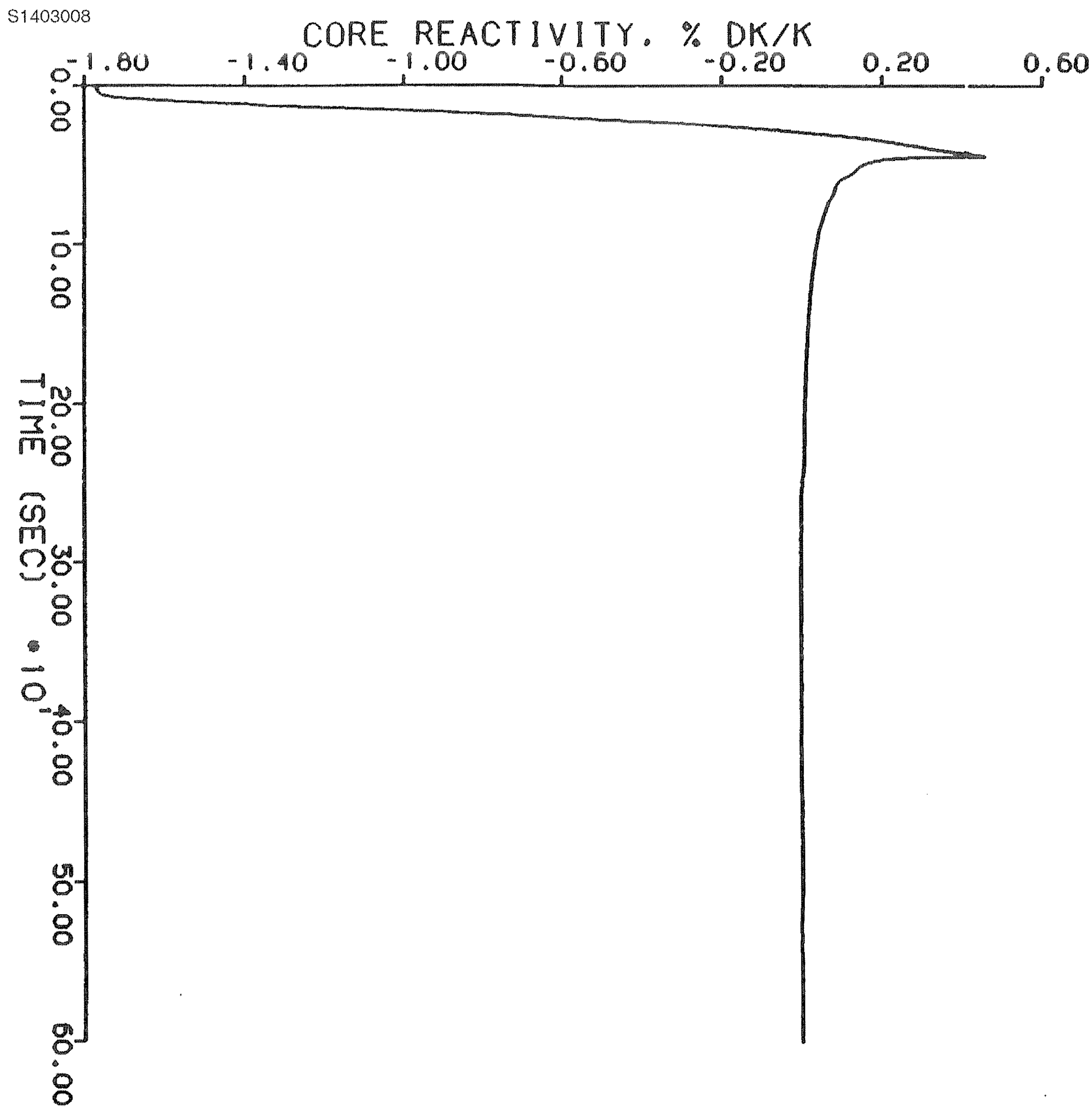
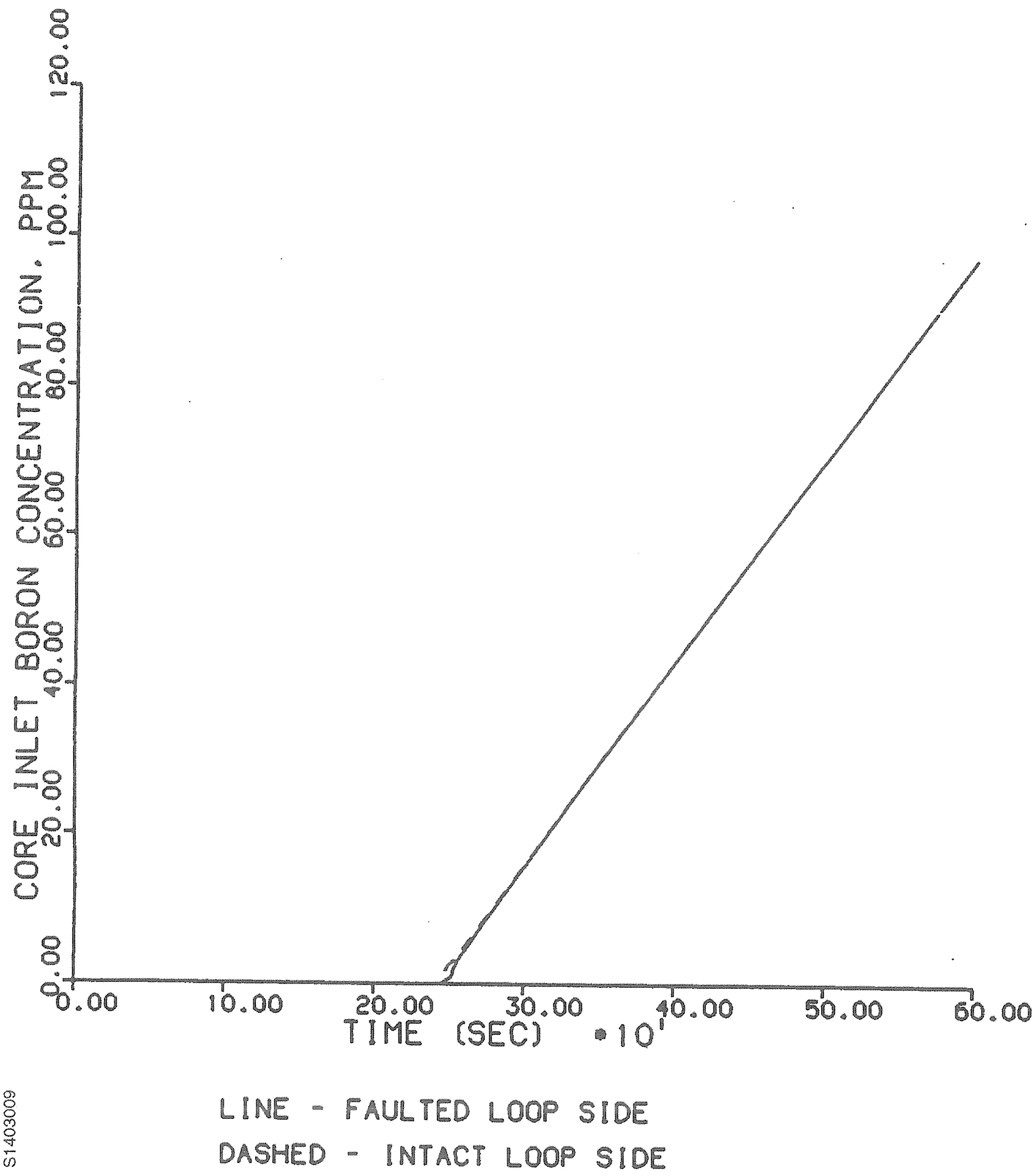


Figure 14.3-12
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
OFFSITE POWER AVAILABLE CORE INLET BORON CONCENTRATION



S1403009

Figure 14.3-13
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
OFFSITE POWER AVAILABLE ACTUAL LOOP AVERAGE TEMPERATURES

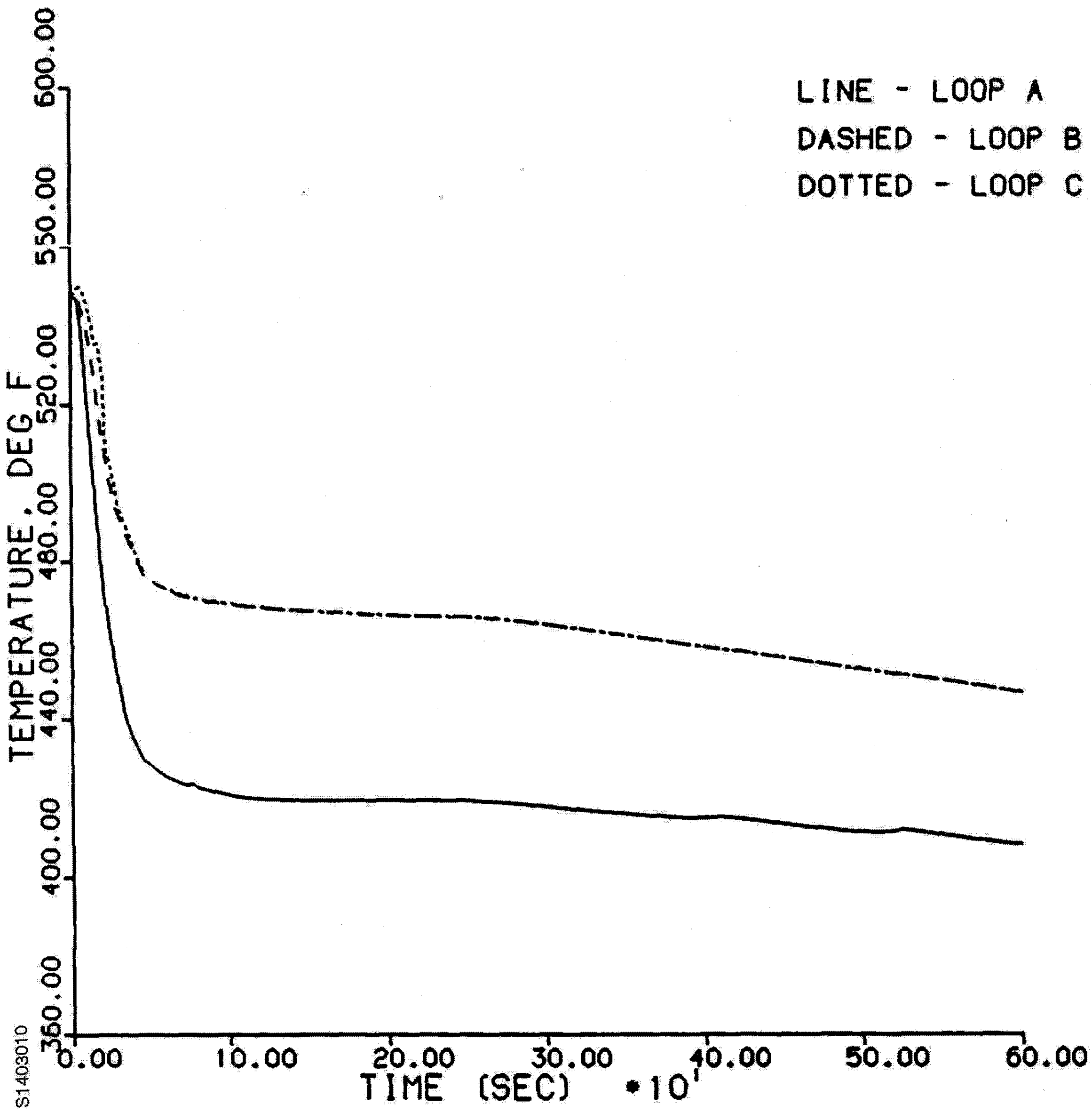


Figure 14.3-14
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK, W/O OFFSITE POWER AVAILABLE NORMALIZED CORE HEAT FLUX (FRACTION OF 2546 MWt)

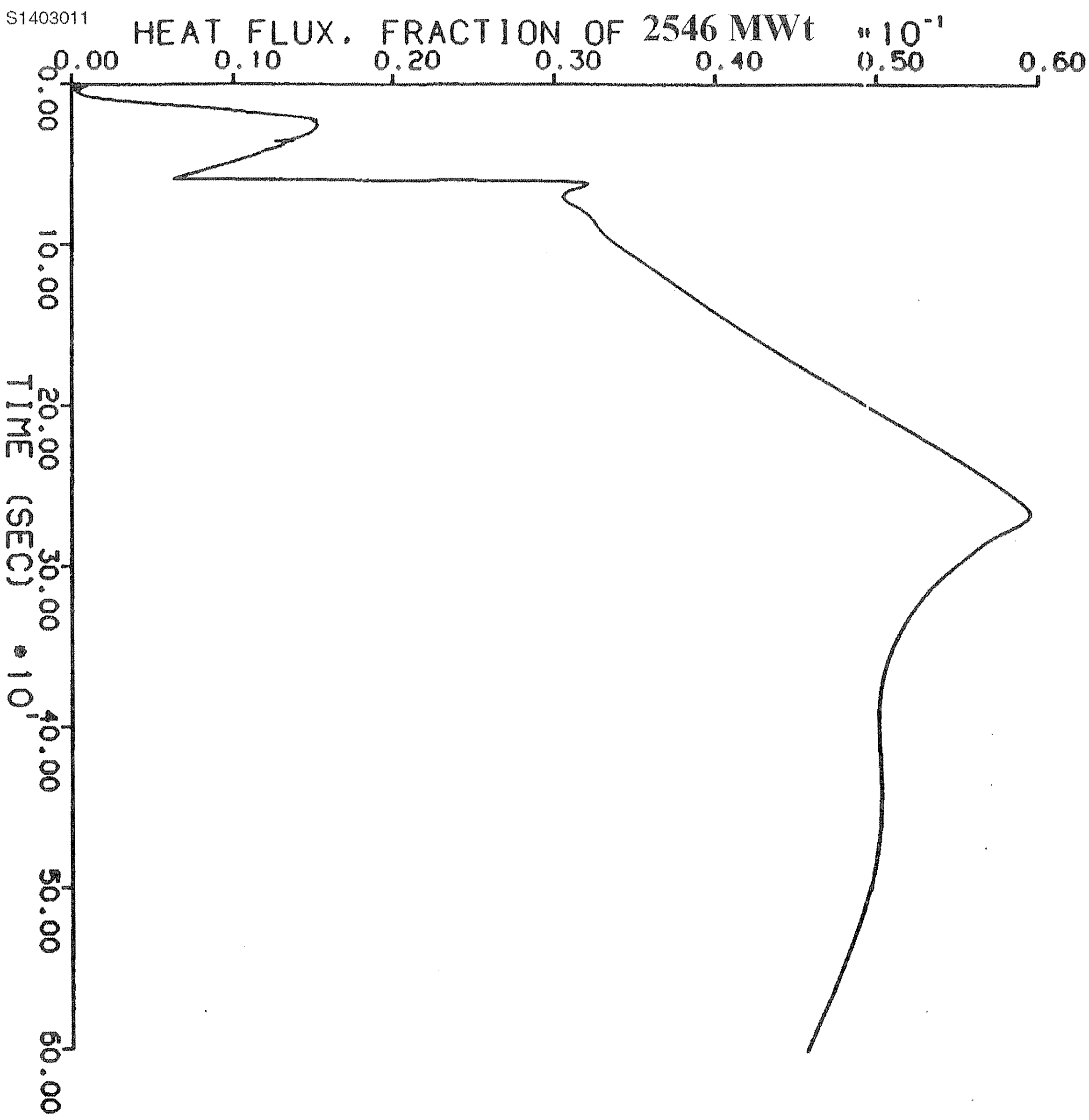


Figure 14.3-15
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
W/O OFFSITE POWER AVAILABLE PRESSURIZER PRESSURE

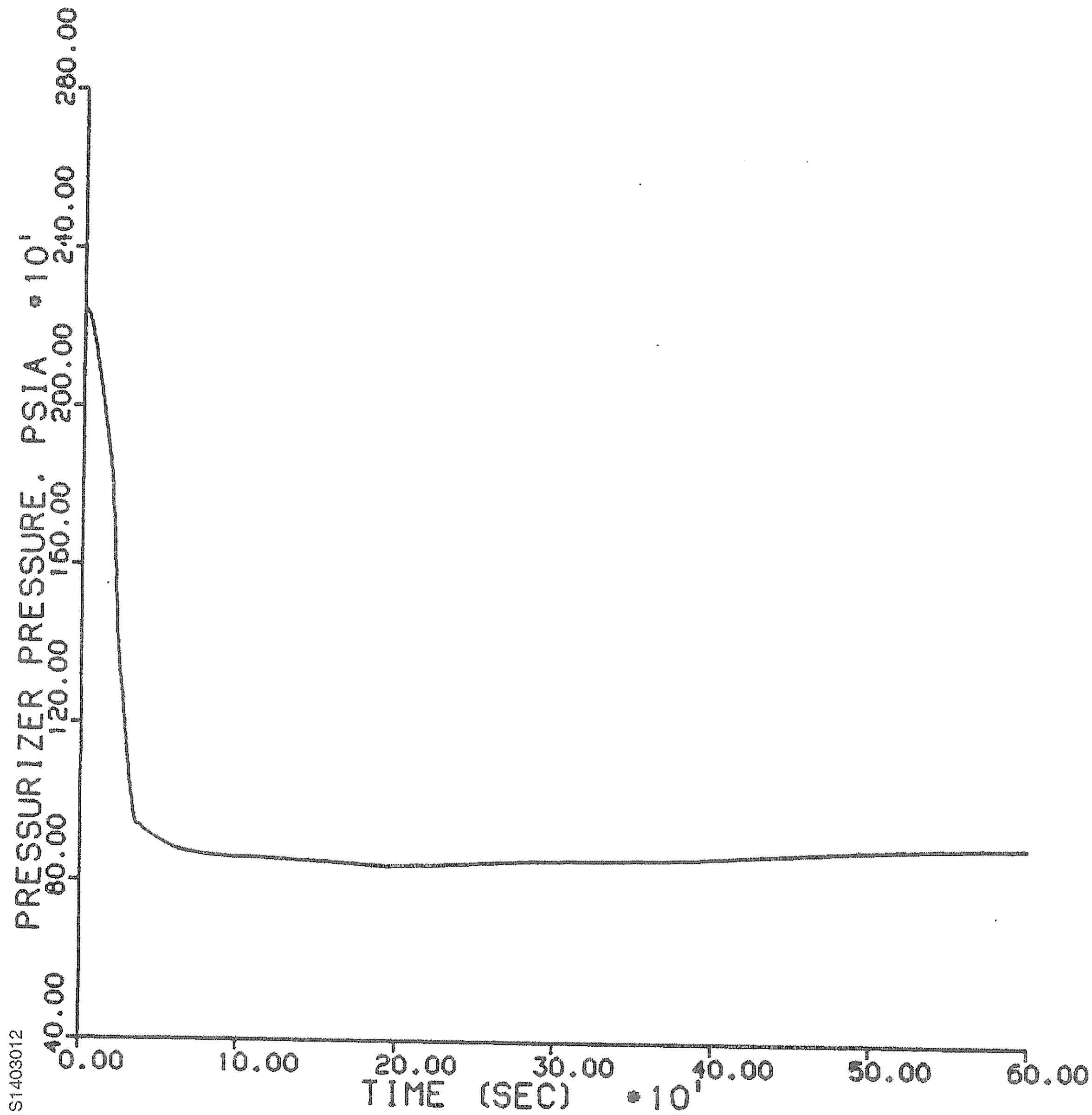


Figure 14.3-16
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
W/O OFFSITE POWER AVAILABLE CORE REACTIVITY,% ΔK/K

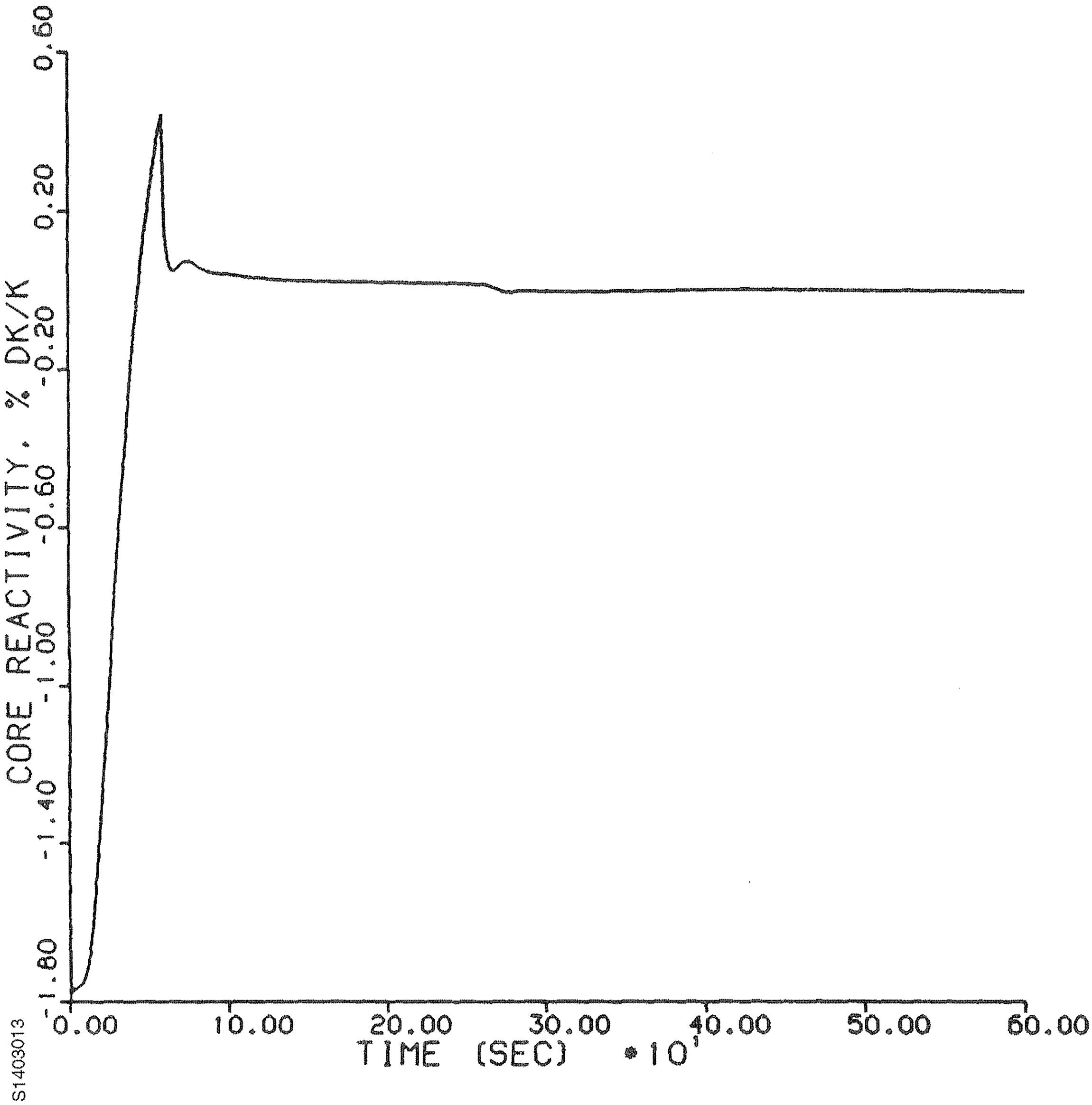


Figure 14.3-17
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
W/O OFFSITE POWER AVAILABLE CORE INLET BORON CONCENTRATION

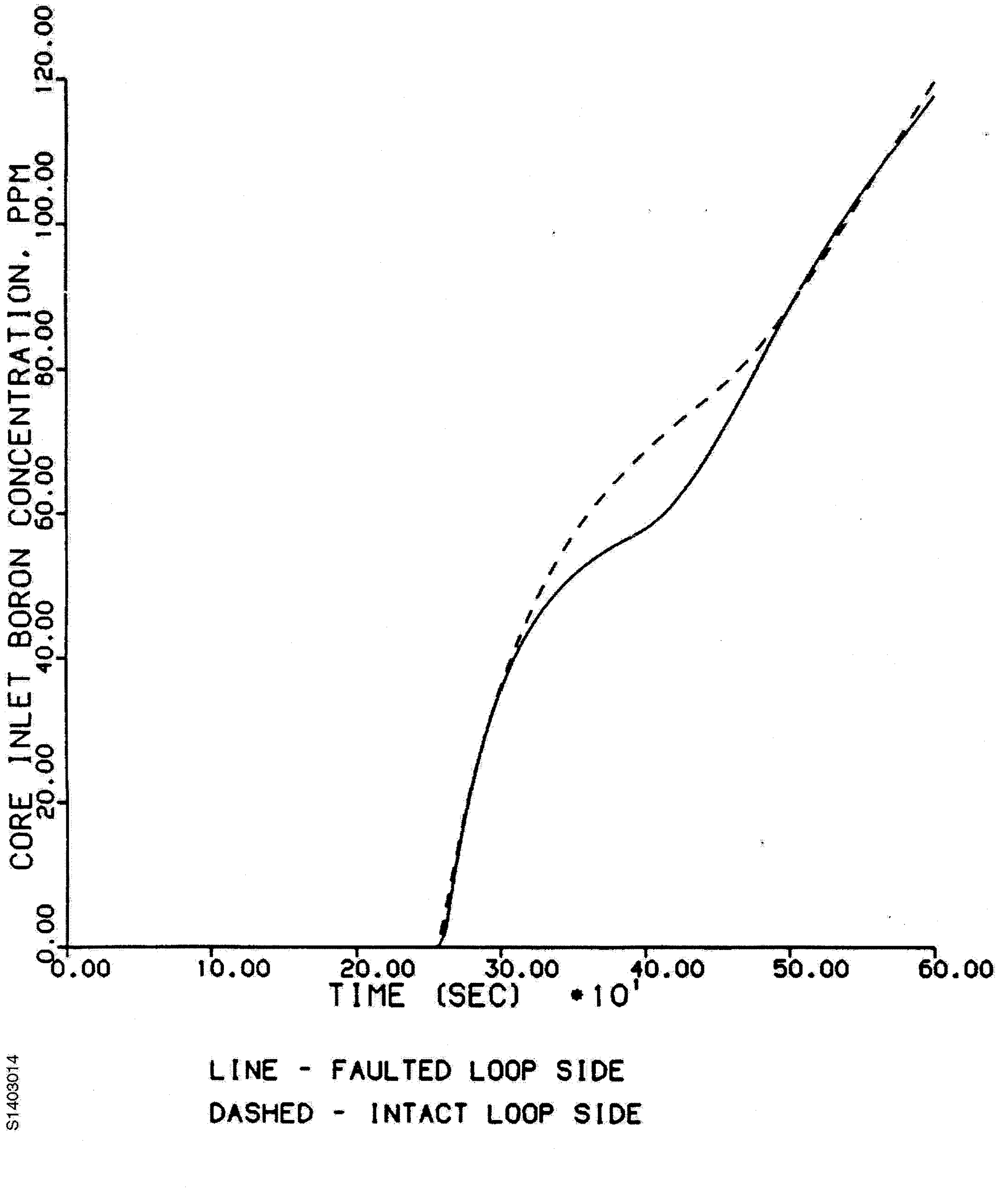


Figure 14.3-18
SPS MAIN STEAMLINE BREAK ANALYSIS 1.4 FT^2 BREAK,
W/O OFFSITE POWER AVAILABLE ACTUAL LOOP AVERAGE TEMPERATURES

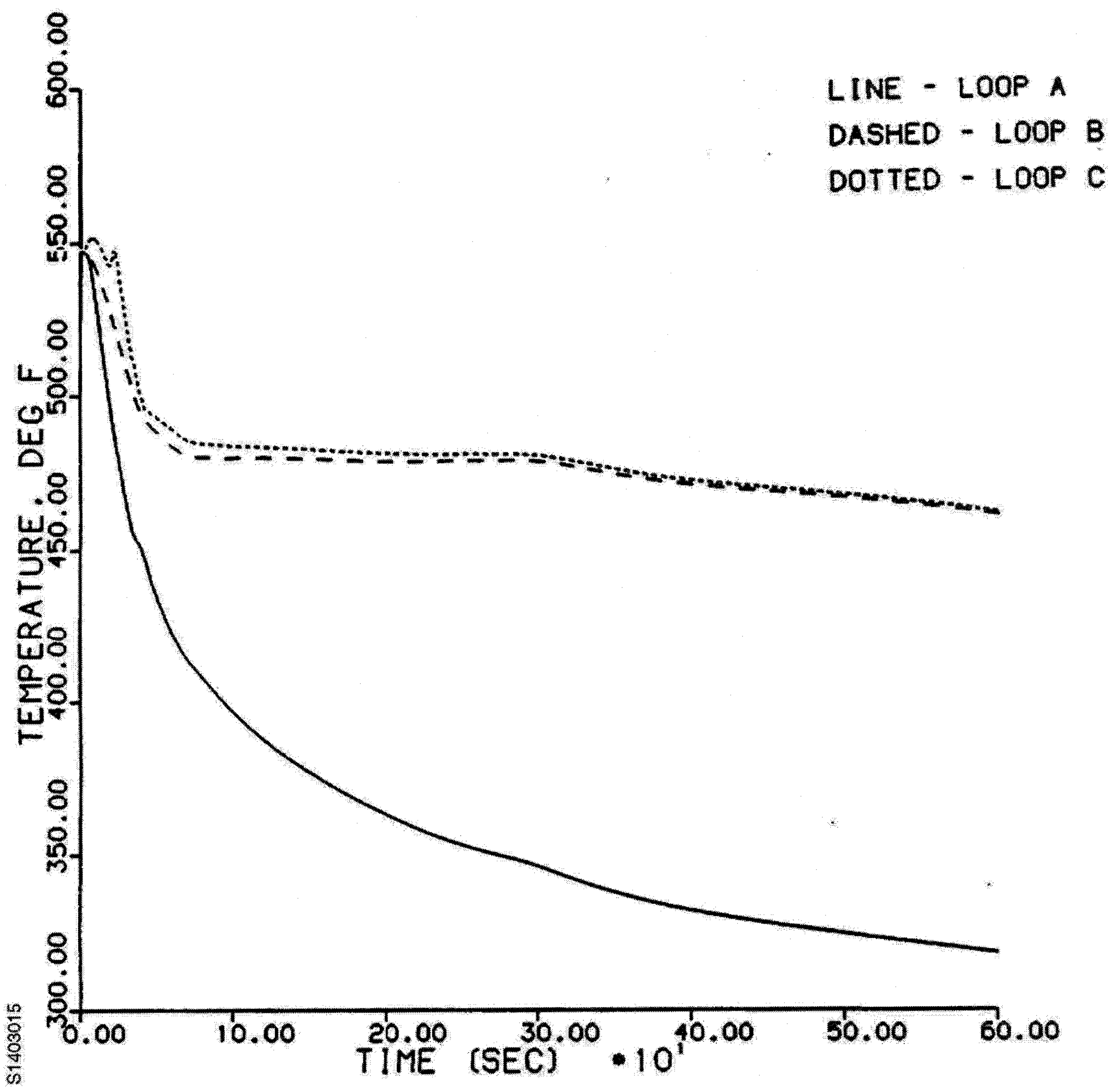


Figure 14.3-19
SPS MAIN STEAMLINE BREAK ANALYSIS CREDIBLE BREAK
NORMALIZED CORE HEAT FLUX (FRACTION OF 2546 MWt)

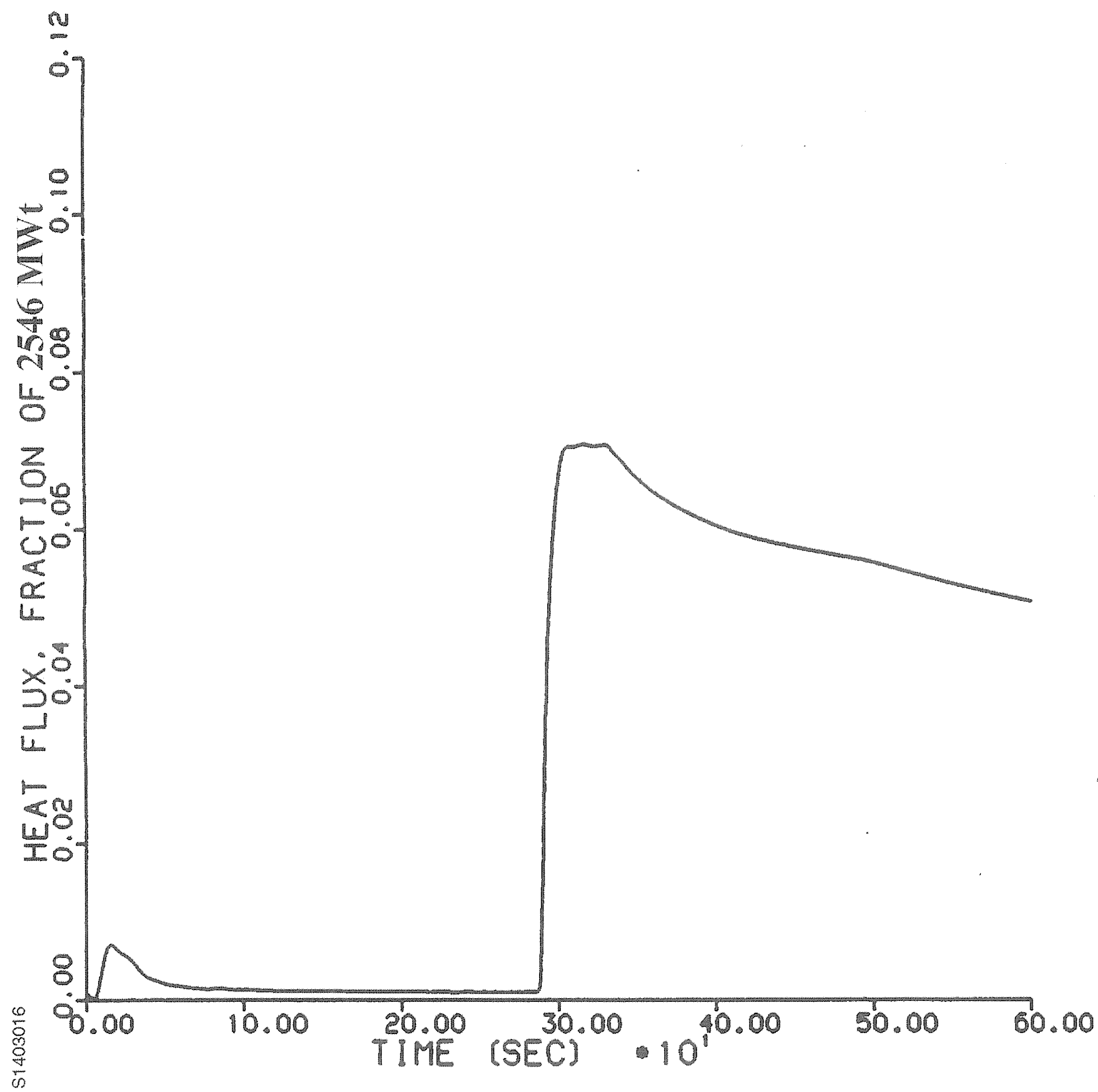


Figure 14.3-20
SPS MAIN STEAMLINE BREAK ANALYSIS
CREDIBLE BREAK PRESSURIZER PRESSURE

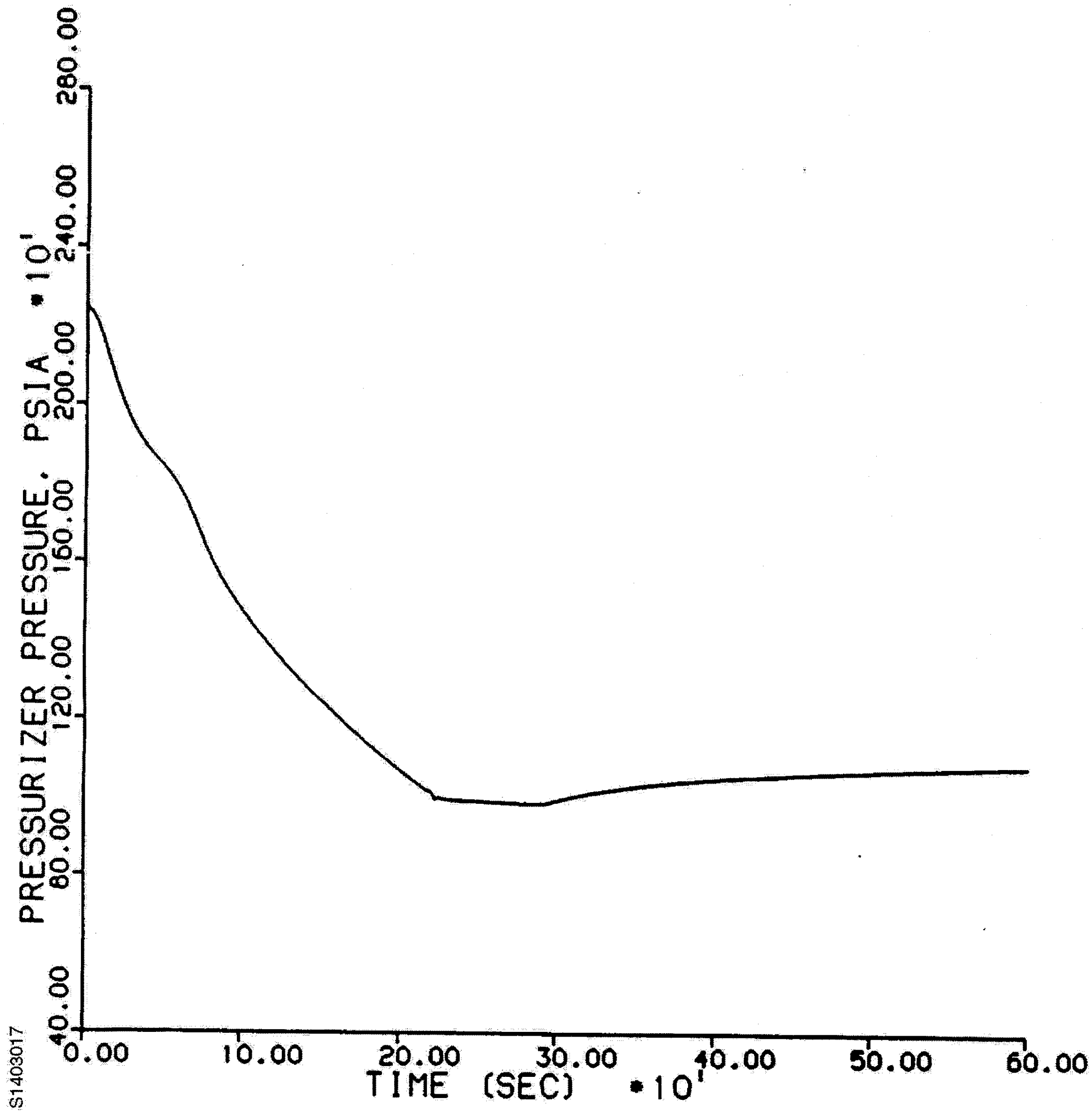


Figure 14.3-21
SPS MAIN STEAMLINE BREAK ANALYSIS
CREDIBLE BREAK CORE REACTIVITY,% ΔK/K

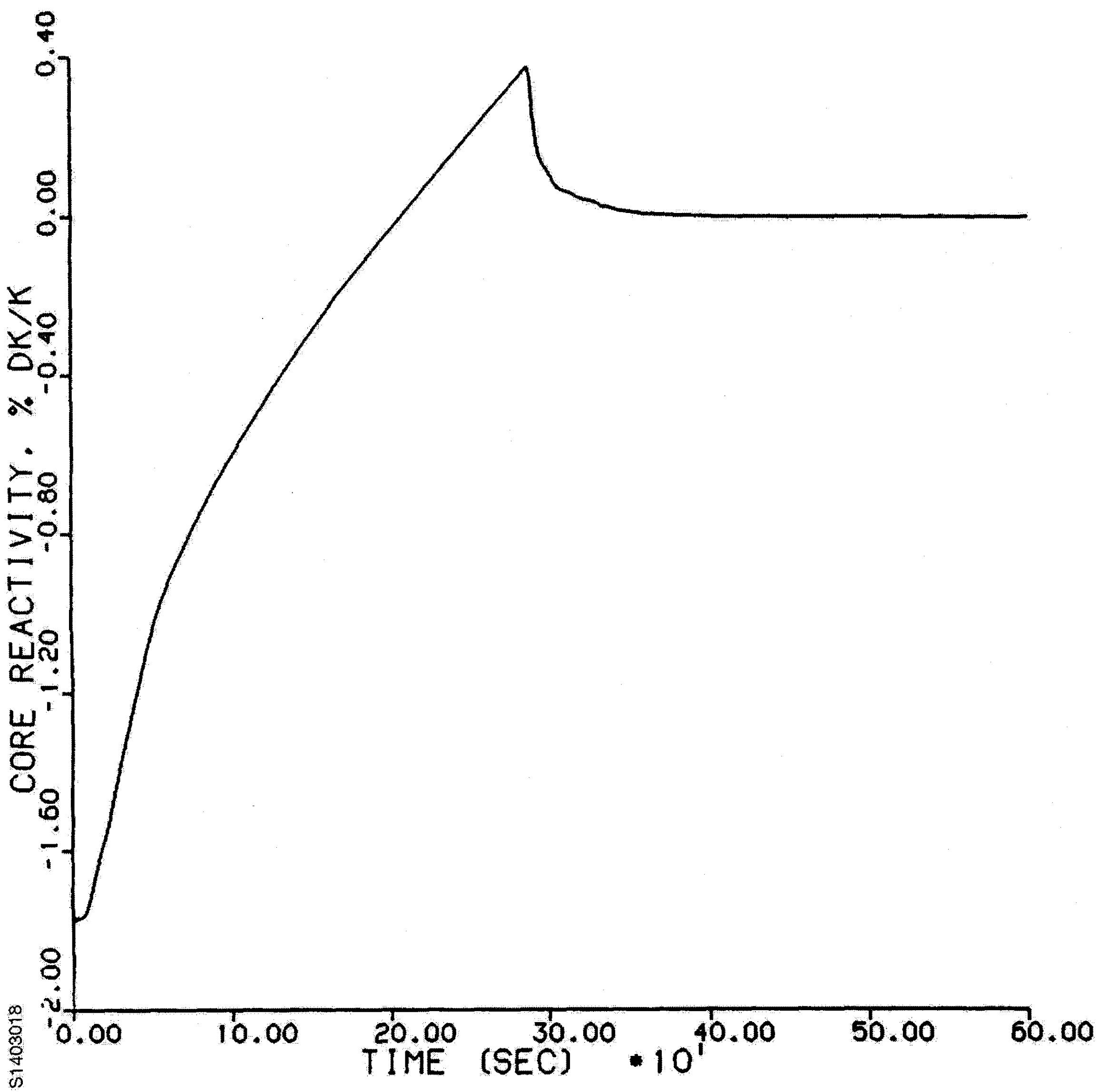


Figure 14.3-22
SPS MAIN STEAMLINE BREAK ANALYSIS
CREDIBLE BREAK CORE INLET BORON CONCENTRATION

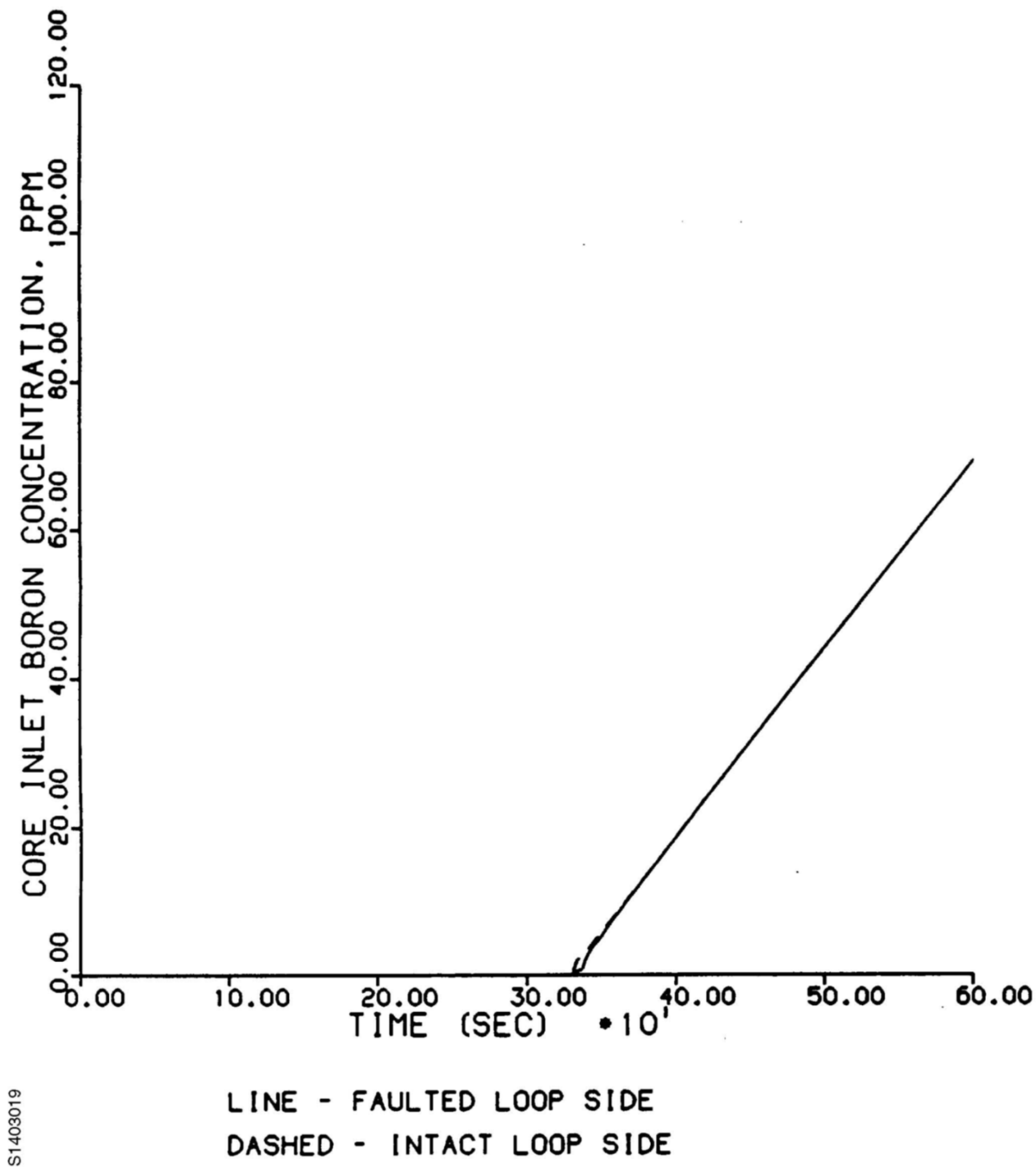


Figure 14.3-23
SPS MAIN STEAMLINE BREAK ANALYSIS
CREDIBLE BREAK ACTUAL LOOP AVERAGE TEMPERATURES

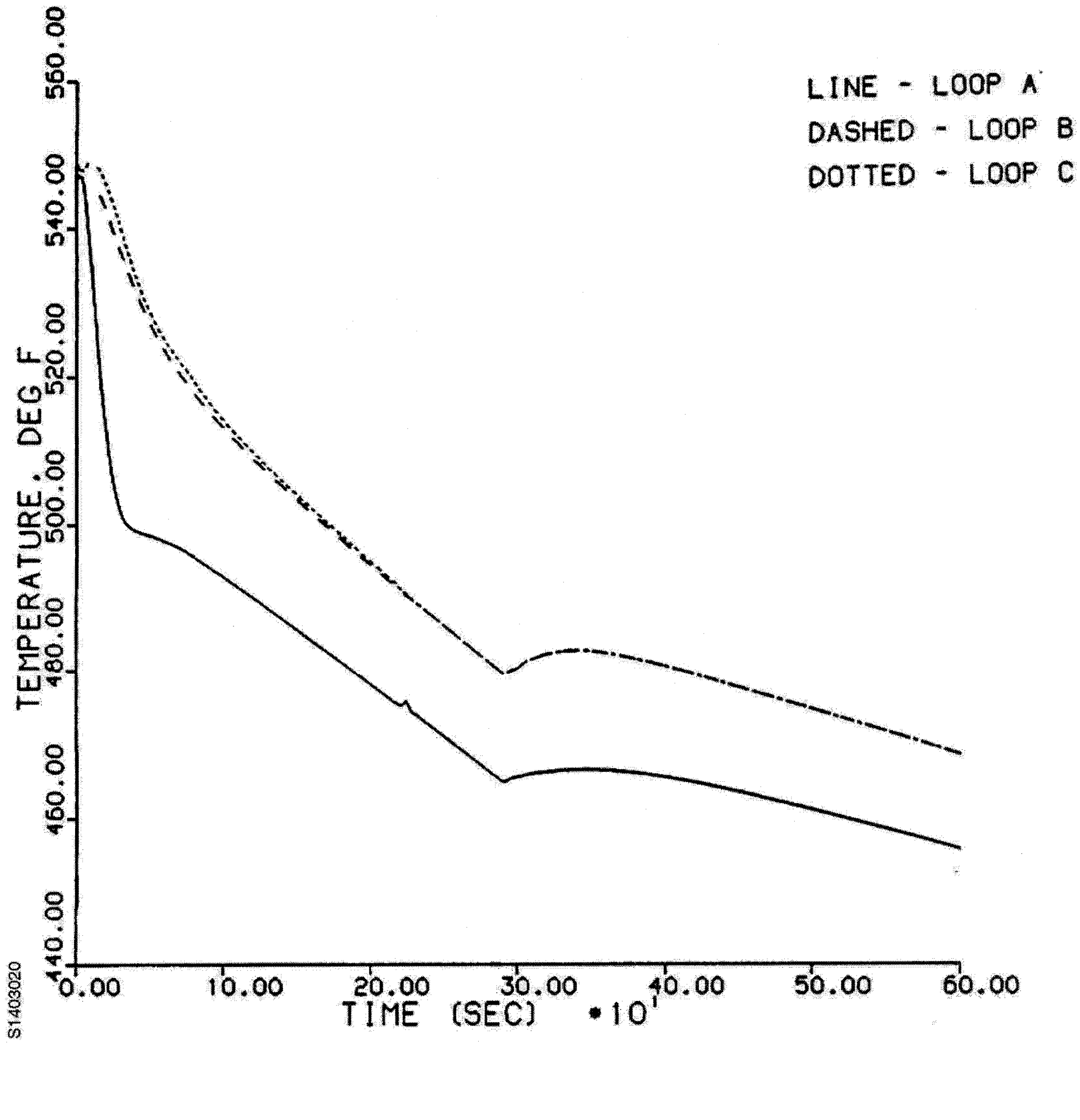


Figure 14.3-24
NUCLEAR POWER TRANSIENT - EOC HFP ROD EJECTION ACCIDENT

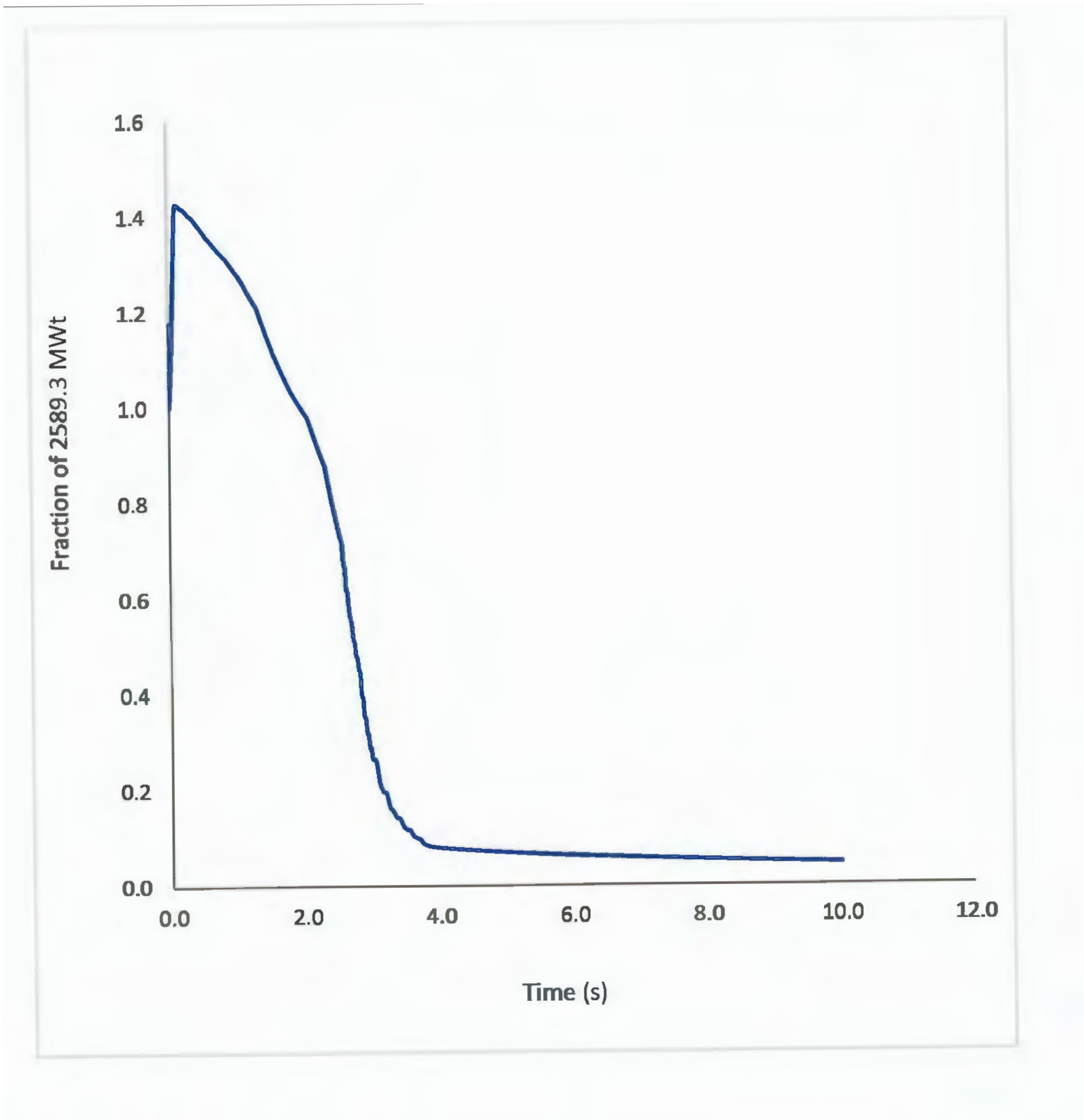


Figure 14.3-25
HOT SPOT FUEL AND CLAD TEMPERATURE VERSUS TIME -
EOC HFP ROD EJECTION ACCIDENT

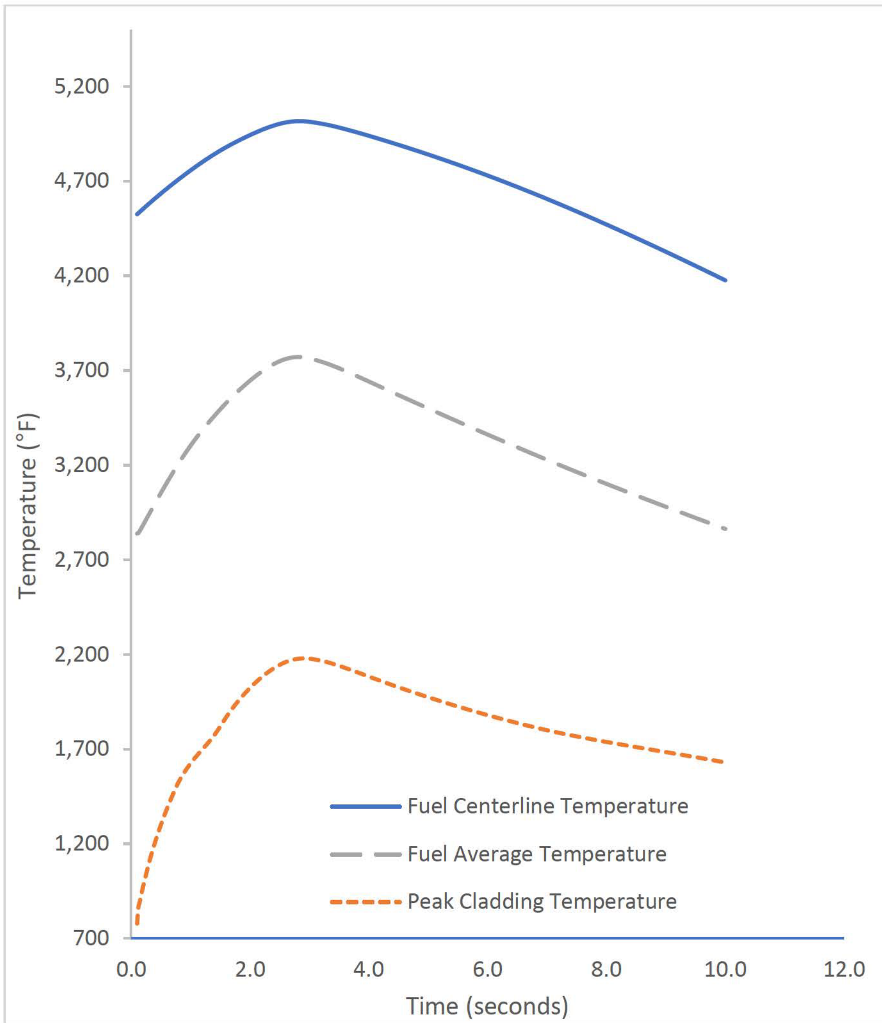


Figure 14.3-26
NUCLEAR POWER TRANSIENT - EOC HZP ROD EJECTION ACCIDENT

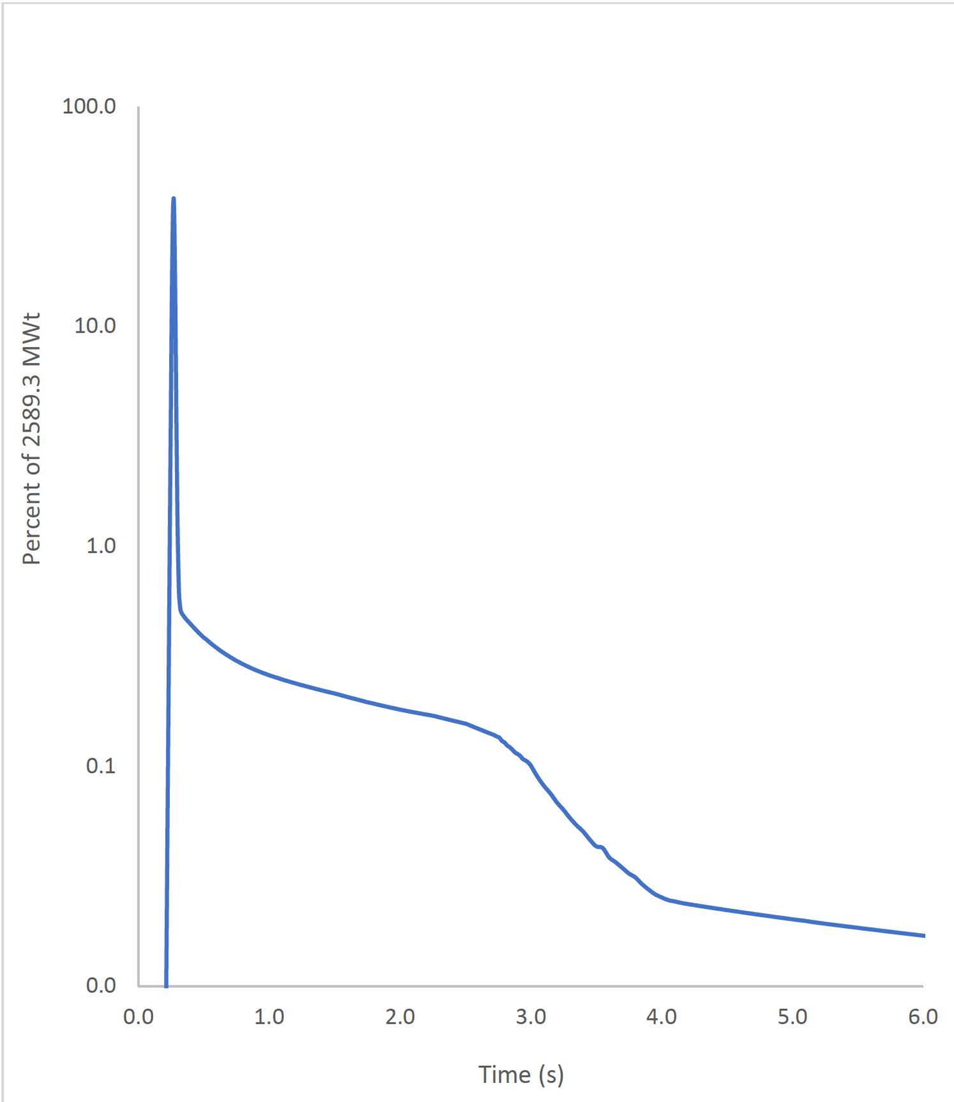


Figure 14.3-27
HOT SPOT FUEL AND CLAD TEMPERATURE VERSUS TIME
EOC HZP ROD EJECTION ACCIDENT

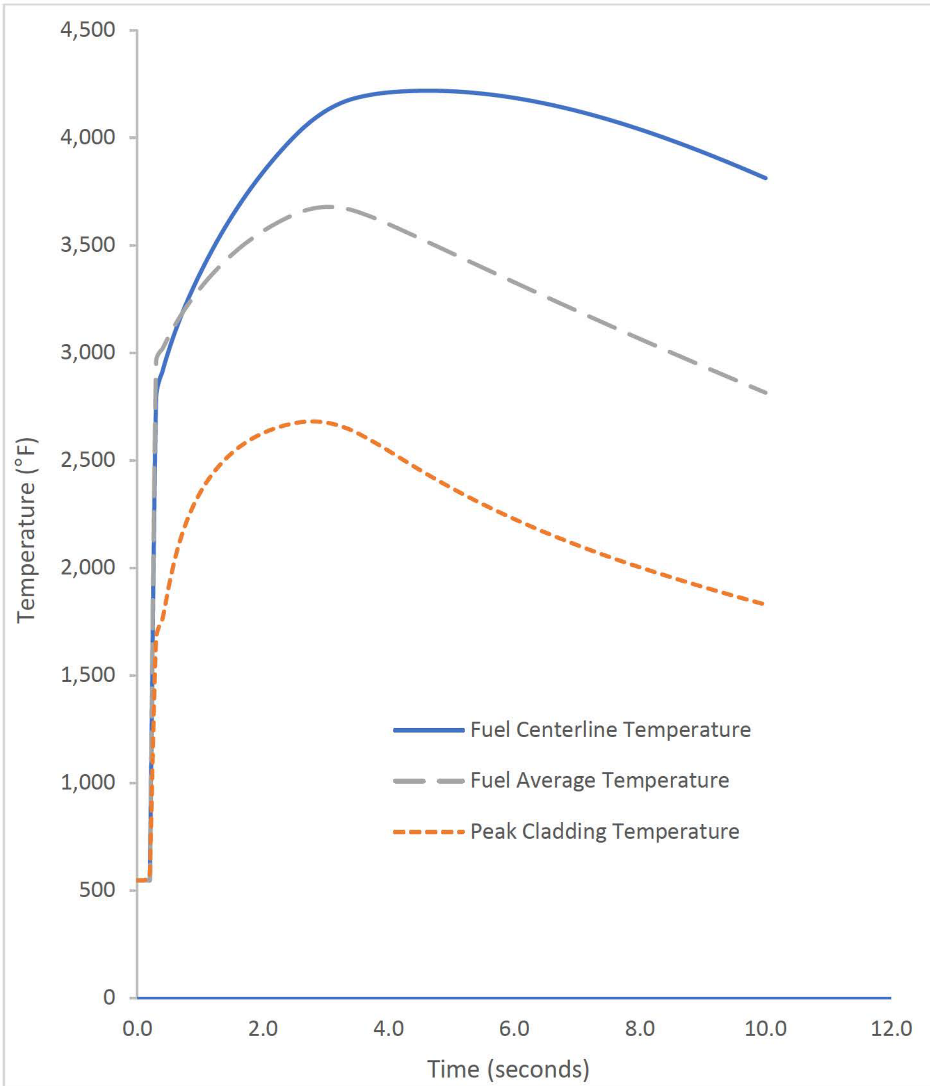


Figure 14.3-28
FUEL ROD POWER LEVEL VERSUS PERCENT OF CORE
VOLUME ROD EJECTION CASE

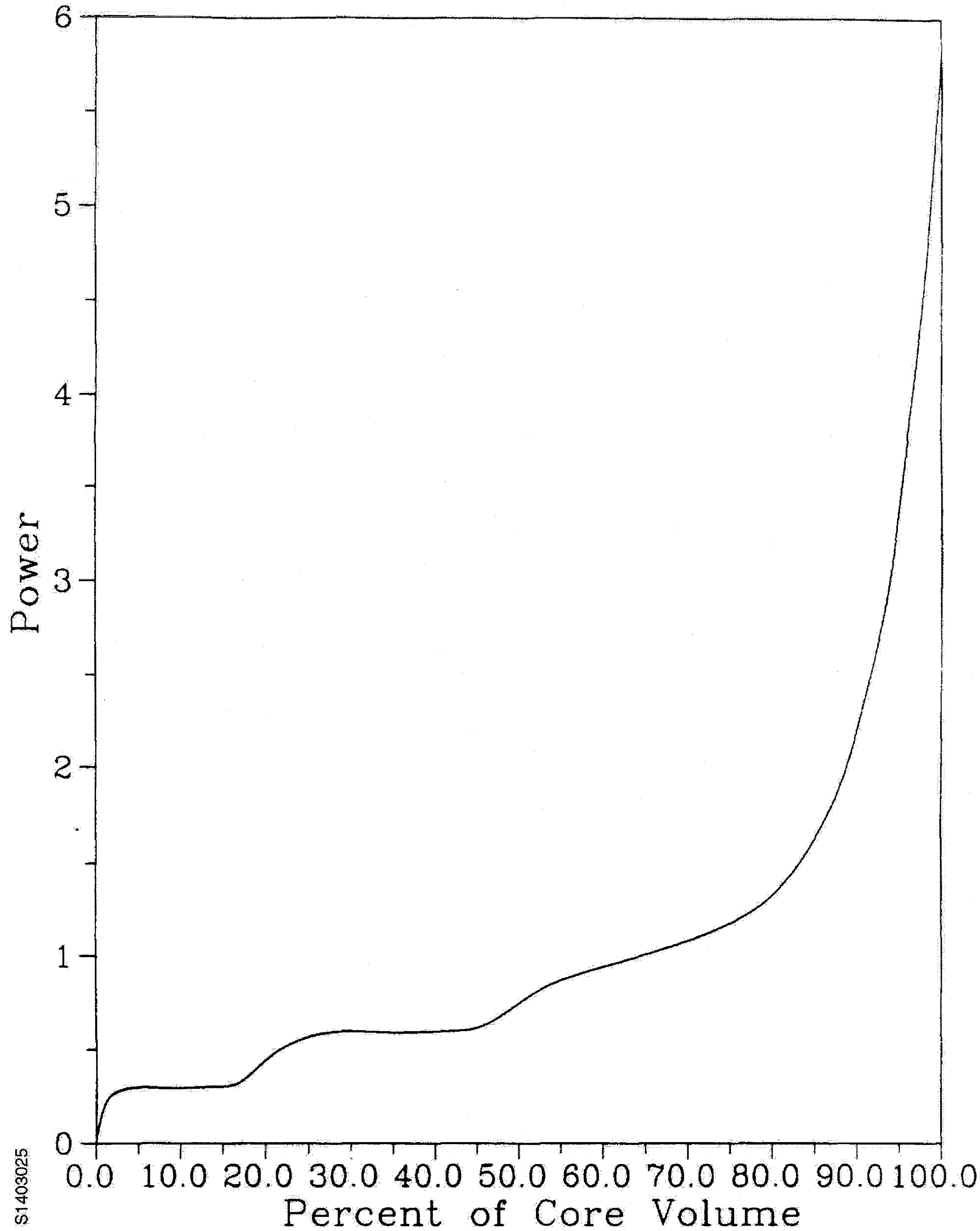


Figure 14.3-29
DELETED)

Figure 14.3-30
DELETED)

Figure 14.3-31
DELETED

Figure 14.3-32
DELETED

Intentionally Blank

14.4 GENERAL STATION ACCIDENT ANALYSIS

14.4.1 Fuel-Handling Accidents

The following fuel-handling accidents are evaluated:

1. A fuel assembly becomes stuck inside the reactor vessel.
2. A fuel assembly becomes stuck in the containment penetration valve (fuel transfer tube).
3. A fuel assembly becomes stuck in the transfer carriage or the carriage becomes stuck.
4. A fuel assembly in the reactor cavity becomes damaged (fuel-handling accident in containment).
5. A fuel assembly in the spent-fuel pool becomes damaged (fuel-handling accident in the spent-fuel pool).
6. A spent-fuel shipping cask is dropped into the cask laydown area of the spent-fuel pool (cask-drop accident).

14.4.1.1 **Accident Prevention or Mitigation**

The possibility of a fuel-handling accident is remote because of the stringent administrative controls and physical limitations imposed on fuel-handling operations. All refueling operations are conducted in accordance with prescribed procedures under the direct surveillance of a supervisor technically trained in nuclear safety. Also, before any refueling operations begin, the verification of complete control-rod assembly insertion is obtained by tripping the control-rod banks and obtaining indication of rod drop and disengagement from the control-rod drive mechanisms. The boron concentration in the reactor coolant is raised to the relatively high refueling concentration and verified by sampling. The refueling boron concentration is sufficient to maintain the clean, cold, fully loaded core subcritical with all control-rod assemblies withdrawn. The refueling cavity is filled with water meeting the same boric acid specifications. As the vessel head is raised, a visual check is made to verify that the control-rod assembly drive shafts are free in the mechanism housing.

After the vessel head is removed, the control-rod assembly drive shafts are removed from their respective assemblies using the manipulator crane hoist and the shaft unlatching tool. A spring scale is used to indicate that the drive shaft is free of the control-rod assembly as the lifting force is applied.

The fuel-handling manipulators and hoists are designed so that fuel cannot be raised above a position that provides adequate shield water depth for the safety of operating personnel. This safety feature applies to handling facilities in both the containment and the spent-fuel pool area. In the spent-fuel pool, the design of storage racks and manipulation facilities is such that:

1. Fuel at rest is held in position by positive restraints in a safe, always subcritical, geometrical array, with no credit for boric acid in the water.

2. Fuel can be manipulated only one assembly at a time.
3. A violation of procedures by placing one fuel assembly in juxtaposition with any group of assemblies in racks will not result in criticality.
4. Crane facilities do not permit the handling of heavy objects, such as a spent-fuel shipping cask, above the fuel racks.

Adequate cooling of spent-fuel during underwater handling is provided by convective heat transfer to the surrounding water. The fuel assembly is immersed continuously while in the refueling cavity or spent-fuel pool.

Even if a spent-fuel assembly becomes stuck in the transfer tube, natural convection maintains adequate cooling. The fuel-handling equipment is described in detail in Chapter 9.

Two nuclear instrumentation system source range channels are continuously in operation and provide a warning of any approach to criticality during refueling operations. This instrumentation provides a continuous audible signal in the containment, and it would annunciate a local horn and a horn and light in the control room if the count rate increased above a preset low level.

The refueling boron concentration is sufficient to maintain the clean, cold, fully loaded core subcritical by at least 5% delta k/k with all control-rod assemblies inserted (Reference 8). At this boron concentration the core would also be subcritical with all control-rod assemblies withdrawn. The refueling cavity is filled with water meeting the same boric acid specifications.

All these safety features make the probability of a fuel-handling accident very low. Nevertheless, it is possible that a fuel assembly could be dropped during the handling operations. Therefore, this accident is analyzed both from the standpoint of radiation exposure and accidental criticality.

Special precautions are taken in all fuel-handling operations to minimize the possibility of damage to fuel assemblies during transport to and from the spent-fuel pool and during their installation in the reactor. All irradiated fuel-handling actions are conducted under water. The handling tools used in the fuel-handling operations are conservatively designed and the associated devices are of a fail-safe design.

In the fuel storage area, the fuel assemblies are spaced in a pattern that prevents any possibility of a criticality accident. The motions of the cranes that move the fuel assemblies are limited to a relatively low maximum speed. Caution is exercised during fuel-handling to prevent a fuel assembly from striking another fuel assembly or structures in the containment or fuel building.

The fuel-handling equipment suspends the fuel assembly in the vertical position during fuel movements, except when the fuel is moved through the transport tube.

The design of the fuel assembly is such that the fuel rods are restrained by grid clips that provide a total restraining force of approximately 60 lb on each fuel rod. If the fuel rods are in contact with the bottom plate of the fuel assembly, any force transmitted to the fuel rods is limited by the restraining force of the grid clips. The force transmitted to the fuel rods during fuel-handling is not sufficient to breech the fuel-rod cladding. If the fuel rods were not in contact with the bottom plate of the assembly, the rods would have to slide against the 60-lb friction force. This would absorb the shock and thus limit the force on the individual fuel rods.

Considerable assembly deformation would have to occur before the rod would make contact with the top plate and place any appreciable load on the fuel rod. In view of the above, it is unlikely that any damage would occur to the individual fuel rods during handling. If one assembly is lowered on top of another, no damage to the fuel rods would occur that would affect the integrity of the cladding.

If during handling the fuel assembly were to strike against a flat surface, the loads would be distributed across the fuel assembly and grid clips and essentially no damage would be expected in any fuel rods.

If the fuel assembly were to strike a sharp object, it would be possible for the sharp object to damage the fuel rods with which it comes in contact, but a breech of the cladding would be unlikely. On this basis, assuming the failure of an entire row of fuel rods (15) is a conservative upper limit.

Preliminary analyses in support of the initial FSAR assumed three extremely remote situations: a fuel assembly is dropped 14 feet and strikes a flat surface; one assembly is dropped onto another; and one assembly strikes a sharp object. The analysis of a fuel assembly assumed to be dropped and striking a flat surface considered the stresses the fuel cladding was subjected to and any possible buckling of the fuel rods between the grid clip supports. The results showed that the axial load at the bottom section of the fuel rod, which would receive the highest loading (approximately 100 lb) was below the critical buckling load (250 lb) and the stresses were relatively low and below the yield stress. For the case where one assembly is dropped on top of another fuel assembly, the loads would be transmitted through the end plates and the control-rod assembly guide tubes of the struck assembly before any of the loads reached the fuel rods.

The end plate and guide thimbles absorb a large portion of the kinetic energy as a result of bending in the lower plate of the falling assembly. Also, energy is absorbed in the struck assembly top end plate before any load can be transmitted to the fuel rods. The results of this analysis indicated that the buckling load on the fuel rods was below the critical buckling loads and the stresses in the cladding were relatively low and below yield.

The experience that has been gained in Westinghouse reactor refueling operations indicates that fuel cladding integrity failures would not be expected to occur during fuel-handling operations.

For the initial FSAR, the rupture of one complete outer row of fuel rods in a withdrawn spent-fuel assembly was assumed as a conservative limit for evaluating the environmental consequences of a fuel-handling accident. The remaining fuel assemblies are protected by the storage rack structure so they are not subjected to lateral bending loads. No damage resulted from the axial application of a load of 2200 lb to a fuel assembly. The maximum load expected to be experienced in service is approximately 1000 lb. This information was used in the fuel-handling equipment design to establish the limits for inadvertent axial loads.

The spent fuel cask drop analysis is discussed in Reference 1 and Reference 22. The fuel handling accident in the containment and the fuel handling accident in the spent fuel pool are described below in more detail. These analyses were performed as part of implementing the alternate source term that is described in RG 1.183 (Reference 13). It should be noted that Surry Power Station has been licensed for fuel burnups up to 62,000 MWD/MTU lead rod burnup beginning with Surry Improved Fuel Assemblies with ZIRLO cladding (Reference 20). Older fuel assemblies with Zircaloy-4 cladding are limited to a lead rod average burnup of 60,000 MWD/MTU (Reference 20). The Optimized ZIRLO cladding was approved by the NRC for use at Surry in Reference 21 as part of the 15 x 15 Upgrade fuel design for lead rod average burnups up to 62,000 MWD/MTU. For this extended burnup it has been shown that the radiological consequences of the fuel handling accidents discussed below remain unchanged (References 2, 3, 4, 19, & 20).

Virginia Power conducted a spent fuel cask drop evaluation in support of the use of spent fuel casks in the fuel building area (References 5 & 6). As a result of this evaluation, cask impact pads were installed in the cask loading area of the spent fuel pool, and the spent fuel pool was divided into two regions for the storage of spent fuel (Reference 7). Region 1 comprises the first three rows of fuel racks (324 storage locations) adjacent to the Fuel Building Trolley Load Block. Region 2 comprises the remainder of the fuel racks in the fuel pool. During spent fuel cask handling, Region 1 is limited to storage of spent fuel assemblies which meet the criteria delineated in Surry Power Station Technical Specification 5.3, *Fuel Storage*.

14.4.1.2 **Fuel-Handling Accident in the Containment**

The fuel handling accident (FHA) in the containment has three postulated release paths. These three pathways are the ventilation system (through Vent Stack No. 2), the open personnel airlock, and the open equipment access hatch. The analysis models the release flow and atmospheric dispersion factors to bound the radiological effects of release from any combination of the three release paths and from penetrations that terminate in the Auxiliary Building and Safeguards. Filtration of the containment release to atmosphere is not credited in the FHA analysis.

14.4.1.2.1 Assumptions

During refueling, the containment purge system may be aligned to exhaust through either the non-safety related or safety-related ventilation filters in the Auxiliary Building or a combination thereof, but no filtration is credited in the analysis. If exhaust is being filtered, more than one filter bank may be on line because the fuel building exhaust could also be aligned through the filters. The containment purge design flow rate to the non-safety-related filters is 20,000 cfm. The design flow rate through a safety-related filter is 36,000 cfm. The containment was modeled arbitrarily as a 1 ft^3 volume with a 500 cfm release flow rate in order to bound all credible releases, maximize dose consequences, and complete the release in 2 hours as required by RG 1.183. The fuel building modeling assumptions are discussed in Section 14.4.1.3.1. The analysis results are not sensitive to release flow rates of the various ventilation systems.

While the purge system is in operation, the air flow in the containment is as follows. Air enters the containment through two 14,500-cfm fans and two 36-inch butterfly supply valves, and is dispersed through the ring header outside the crane wall at Elevation 39 ft. 6 in. The air is continuously recirculated inside the containment by three 75,000-cfm recirculation fans. The air is purged from the containment through the ring header at Elevation -20 ft. outside the crane wall. The air discharges through two 36-inch butterfly valves in series. The air then passes through the auxiliary building filter banks and the two 36,000 cfm filter exhaust fans. Air is also assumed to flow through the personnel airlock, equipment access hatch, and other containment penetrations (if these are open).

The worst single failure would be either the inability to close one of the hatches or the loss of the valve-closing circuit that closes the valves and secures the purge fans on an alarm from either the manipulator crane monitor or the containment gas and particulate monitors. The two output relays are sufficiently redundant to secure purge flow; however, a loss of power to this circuit would cause them not to function. Failure to isolate containment or establish containment closure could cause a release to the atmosphere with a boundary dose as calculated below. Even though containment isolation, containment closure, and filtering of the release are not credited in the analysis, the dose is still within allowable limits (Table 14.4-5).

The transit time for any released activity from the radiation detection point to the control room normal ventilation system intake is calculated to be two minutes and the control room manual isolation was modeled as occurring ten minutes after radioactive material reached the control room air inlet. The control room isolation dampers close within 20 seconds of manual isolation. This progression relies upon the operability of the manipulator crane area monitor and the containment gas and particulate monitors in conjunction with communications to provide a timely and valid indication of a FHA.

Within 1 hour of initiation of the event, procedures require the alignment of the control room emergency ventilation system to provide a filtered breathing air supply to the control room envelope. This analysis considered that one fan was operational which provides a control room intake flow rate of 900 cfm from 1 hour through the end of the 30-day dose calculation period. Operation of additional fans will not increase the consequences of the FHA. An unfiltered inleakage of 250 cfm is assumed when the control room is isolated (0-30 days). Normal ventilation flow into the control room is modeled at 3300 cfm. Before isolation, 250 cfm of unfiltered inleakage is added to the normal ventilation flow.

The control room χ/Q values were determined with ARCON96 (Reference 11) methodology and meteorological data for the 2009 through 2013 time period. These values are listed in Table 14.4-3. The control room occupancy factors in Table 14.4-4 were also incorporated into the dose calculations to reflect that personnel would not be exposed to the released activity 100% of the time over the entire 30 day period. The breathing rate used for the control room dose calculations was 3.5×10^{-4} m^3/sec.

More specific conservative assumptions are:

1. A release of fission gases contained in the fuel rod gap occurs as the result of the rupture of all the fuel rods in a fuel assembly in the reactor fuel cavity. The release volume is modeled as a one cubic foot volume with a 500 cfm exhaust flow rate. The release is assumed to occur linearly over a 2-hour duration and is assumed to homogeneously mix within the conservatively small release volume and immediately begins to exhaust into the environment at the indicated flow rate.

2. The manipulator crane area monitor is gamma radiation sensitive, so that it is not necessary for it to be immersed in a radioactive cloud to detect radioactivity. Its position above the fuel cavity (approximately 10 feet), unshielded from direct gamma rays from the cavity, enhances its capability to detect an accident release immediately.

3. The containment closure is not credited even though the equipment hatch and the personnel airlock will be capable of being closed, and all other containment penetrations will either be closed, capable of being closed, or have an operable isolation valve.

4. The delay time from reactor shutdown to the initiation of fuel assembly transfer operations is at least 100 hours.

5. The assembly radial peaking factor is 1.70, which is the appropriate peaking factor, including uncertainties, for events (e.g., FHA) that do not employ the Statistical DNBR Evaluation Methodology. This value is a multiplier applied to the core average isotopic activity to determine bounding activity. The core average activity per fuel assembly was multiplied by this peaking factor and then by the gap fractions prescribed in PNNL-18212 Revision 1. After applying appropriate decontamination factors from the pool, the result is the activity released to the atmosphere of the release volume.

6. The number of fuel assemblies in the core is 157.

7. Eight percent of the fuel assembly Iodine-131 activity is assumed to be released into the reactor cavity water, as are nine percent of Iodine-132 activity, and five percent of the other iodine isotopes present in the fuel assembly, 99.85% being elemental and 0.15% in the organic form. The effective decontamination factor for a depth of water of 23 feet or greater above the damaged fuel rods is 200, as prescribed in RG 1.183 and DG-1199 Revision 1.

8. Eight percent of each of the noble gases present in the fuel assembly is released to the reactor cavity pool, with the exception of Kr-85; 38% of Kr-85 is released. The DF of the water for noble gases is 1.

9. The calculational method includes dose conversion factors for each isotope.

10. The χ/Q values used in the offsite dose analysis were calculated using the PAVAN (Reference 10) methodology and are based on site specific meteorological data for the 2009 through 2013 time period. These χ/Q values are listed in Table 14.4-2.

11. The breathing rate for the LPZ calculation was 3.5×10^{-4} m^3/sec for the first 8 hours, 1.8×10^{-4} m^3/sec from 8-24 hours, and 2.3×10^{-4} m^3/sec from 24 hours until the end of the accident. The breathing rate for EAB dose calculation was 3.5×10^{-4} m^3/sec for the entire event.

12. The distance from the possible release point to the site boundary varied from a minimum of 1640.4 feet to a maximum of 5059.1 feet.

The activity for the limiting fuel assembly is calculated using the following equation:

Fuel assembly activity (Ci) = Total activity in the core at core-average power after a 100-hr decay $\times \frac{1}{157} \times 1.70$.

14.4.1.2.2 Results

The results of the FHA dose calculations are shown in Table 14.4-5. The doses in Table 14.4-5 are a composite of the worst doses from an FHA in either the containment or the fuel building. A fuel-handling accident in the containment will not lead to EAB and LPZ doses exceeding the dose limits as specified in Regulatory Guide 1.183. Also, the control room doses will not exceed the 10 CFR 50.67 dose limit.

14.4.1.3 **Fuel-Handling Accident in the Spent-Fuel Pool**

If a fuel assembly is dropped in the spent-fuel pool in the fuel building, the increase in radiation level as these radionuclides mix with the fuel building air will be detected by the two radiation monitors located in the ventilation vent no. 2 or by the fuel pool bridge area monitor.

The fuel building exhaust may be diverted through the particulate and activated charcoal filter banks during refueling operations but no filtration is credited in the analysis (Section 9.13). The monitors alarm on a high radiation level to indicate a possible dropped-fuel-assembly incident.

14.4.1.3.1 Assumptions

To determine the quantity of radioactive material available for release, it is conservatively assumed that the fuel assembly with the peak fission product inventory is the one damaged. The inventory is based on maximum full power operation at the end of core life immediately preceding shutdown and a conservative radial peaking factor which is applied to all fuel rods in the assembly. Only that fraction of the fission products which migrates from the fuel matrix to the gap and plenum regions of the fuel rods during normal operation is considered to be available for immediate release into the water in the event of clad damage. The quantity of radioactive material released subsequent to the immediate release is considered to be negligible compared to the quantity released immediately after the Fuel Handling Accident (FHA).

The fuel radionuclide inventory was based on a core power level of 2605 MWt. This core power level is conservative compared to 100.38% of the uprated power level of 2587 MWt (i.e., 2596.9 MWt).

For analyses employing alternative source terms, the FHA is discussed in Section 15.0.1 of the NRC's Standard Review Plan and Regulatory Guide 1.183. The following assumptions were made for the evaluation of the Surry control room and offsite doses due to a FHA.

1. The accident occurs 100 hours after shutdown. Surry Technical Specification 3.10 requires a minimum 100-hour period between the shutdown of a unit and initiation of fuel movement, so the use of a 100-hour time period is conservative. Radioactive decay of the fission product inventory during the 100-hour interval between shutdown and the assumed commencement of fuel handling is incorporated into the analysis.
2. The minimum water depth between the top of the damaged fuel rods and the water surface is 23 feet.
3. All of the gap activity in the damaged rods at the time of the accident is released. The gap activity consists of 38% of the Kr-85, 8% of the noble gases other than Kr-85, 8% of the I-131, 9% of the I-132 and 5% of the radioactive iodine other than I-131 and I-132 in the rods.
4. The values assumed for individual fission product inventories are calculated assuming full power operation at the end of core life immediately preceding shutdown.
5. The iodine gap inventory is composed of 99.85% inorganic species and 0.15% organic species.
6. The pool effective decontamination factor is 200 (i.e., 99.5% of the total iodine released from the damaged rods is retained by the water).

   This difference in decontamination factors for inorganic and organic iodine species results in the iodine above the fuel pool being composed of 70% elemental and 30% organic species.
7. The retention of the noble gases in the water is negligible.
8. A release of fission gases contained in the fuel rod gap occurs as the result of the rupture of all the fuel rods in a fuel assembly in the spent fuel pool. The release volume is modeled as a one cubic foot volume with a 500 cfm exhaust flow rate. The release is assumed to occur linearly over a 2-hour duration and is assumed to homogeneously mix within the conservatively small release volume (1 ft3) and immediately begins to exhaust into the

environment at the indicated flow rate. No credit was taken for filtration via the ventilation exhaust system.

The amount of radioactive material which is released to the fuel building or containment during a FHA at 100-hour period of decay is determined from this core inventory using the following assumptions:

1. All rods in one fuel assembly are damaged.
2. There are 157 fuel assemblies in the Surry core.
3. The assembly radial peaking factor is 1.70, which is the appropriate peaking factor, including uncertainties, for events (e.g., FHA) that do not employ the Statistical DNBR Evaluation Methodology. This value is a multiplier applied to the core average isotopic activity to determine bounding activity. The core average activity per fuel assembly was multiplied by the peaking factor and then by the gap fractions prescribed PNNL-18212 Revision 1. After applying appropriate decontamination factors from the pool, the result is the activity released to the atmosphere of the release volume.
4. Gap fractions as defined above.
5. Decontamination factors as defined above.

The resulting activities released to the fuel building or containment are given in Table 14.4-1.

The RADTRAD-NAI computer code system (Reference 9) was used to calculate doses for the FHA.

The χ/Q values which were used to calculate the exclusion area boundary (EAB) and low population zone (LPZ) doses were calculated using the PAVAN (NUREG/CR-2858) methodology and were based on site specific meteorological data for the 2009 through 2013 time period. The χ/Q values are listed in Table 14.4-2.

The transit time for any released activity from the radiation detection point at the water surface to the control room normal ventilation system intake is calculated to be two minutes and the control room manual isolation was modeled as occurring ten minutes after the radioactive material reached the control room air inlet. The control room isolation dampers close within 20 seconds of manual isolation. This assumption relies upon the operability of the fuel pit bridge area monitor and the ventilation vent No. 2 gas and particulate monitors in conjunction with communications to provide a timely and valid indication of a FHA.

Within 1 hour of initiation of the event, procedures require the alignment of the control room emergency ventilation system to provide a filtered breathing air supply to the control room envelope. This analysis considered that only one fan was operational which provides a control room intake flow rate of 900 cfm from 1 hour through the end of the 30-day dose calculation period. An unfiltered inleakage of 250 cfm is assumed when the control room is isolated

(0-30 days). Normal ventilation flow into the control room is modeled at 3300 cfm. Before isolation, 250 cfm of unfiltered inleakage is added to the normal ventilation flow.

The control room χ/Q values were determined with the ARCON96 (Reference 11) methodology and meteorological data for the 2009 through 2013 time period. These values are listed in Table 14.4-3. The control room occupancy factors in Table 14.4-4 were also incorporated into the dose calculations to reflect that personnel would not be exposed to the released activity 100% of the time over the entire 30 day period. The breathing rate used for the control room dose calculations was 3.5×10^{-4} m^3/sec which is consistent with Reference 13.

14.4.1.3.2 Results

The results of the FHA dose calculations are shown in Table 14.4-5. The doses in Table 14.4-5 are a composite of the worst doses for an FHA in either the containment or the fuel building.

The EAB and LPZ doses for a FHA are less than the dose limits presented in Regulatory Guide 1.183 as shown in Table 14.4-5. The control room doses for the FHA are less than the 10 CFR 50.67 limit, which is also indicated in Table 14.4-5.

14.4.1.3.3 Analysis for High-Density Spent-Fuel Racks

The use of high density fuel racks does not affect the dose consequences resulting from a fuel handling accident in the spent fuel pool. Therefore the analysis provided in the Fuel Handling Accident in the Spent Fuel Pool in Section 14.4.1.3 remains bounding for the use of high density fuel storage racks.

14.4.2 Radioactive Gas Release

The concentration of radioactive waste gases in the primary and auxiliary systems is a function of the rate of fission gas release to the coolant from defective fuel and the rate of gas removal by auxiliary systems. The components that retain significant concentrations of radioactive gases are the volume control tank and the waste gas decay tanks. The radioactive release analysis considers the rupture of the volume control tank and a waste gas decay tank with an instantaneous release of the radioactive gas inventories of each tank to the environment.

14.4.2.1 **Volume Control Tank Rupture**

In this analysis, the volume control tank (VCT) is assumed to rupture and release to the atmosphere all the gases that have collected in the vapor space of the tank. Also released are all the gases in the liquid inventory of the tank and in the volume of liquid that continues to flow into the tank until it is isolated. Isolation is assumed to take 25 minutes, and the flow rate of the entering liquid is assumed to be 160 gpm, a conservatively high letdown flow rate.

The maximum activities of the gases in the vapor space with 1% failed fuel are listed in Table 14.4-6. The activities of the gases in the liquid are based on the reactor coolant equilibrium activities with 1% failed fuel as listed in Table 14.3-16. For the accident analysis, activities in the liquid have been corrected for density. The analysis follows the guidance of NRC Branch Technical Position ETSB (Effluent Treatment Systems Branch) 11-5.

Using these sources and an atmospheric dispersion factor of 9.43×10^{-4} sec/m^3, and assuming a puff ground level release, the two-hour whole-body dose at the EAB is below the 10 CFR 100 limit, and below the 0.5 REM limit contained in Branch Technical Position 11-5.

14.4.2.2 **Waste Gas Decay Tank (WGDT) Rupture**

Surry has two Waste Gas Decay Tanks that collect the gases stripped from the primary coolant system by the primary coolant clean-up systems. One tank is charged with waste gases being removed from the primary system while the other tank is used to hold up the gases for decay and controlled release. The analysis of doses from rupture of a WGDT assumes rupture of a WGDT with the release of the maximum inventory allowed by Technical Specifications.

14.4.2.2.1 WGDT Analysis Assumptions

The whole body EAB dose from the rupture of a WGDT was determined based on a puff release as the product of the (l) curies released, (2) dose conversion factor for Xe-133 and (3) EAB χ/Q. This analysis does not require any computer code. As explained in Reference 15, the WGDT control room dose was bounded by doses determined for other accident conditions. Although some iodine may be present in the tank, the amount are orders of magnitude below those considered for other accidents.

14.4.2.2.2 Dose Analysis for WGDT Rupture

The maximum WGDT inventory allowed by Surry Technical Specification 3.11 is 24,600 curies, (considered as Xe-133). The χ/Q for the EAB is 9.43×10^{-4} sec/m^3. The whole body dose conversion factor for Xenon-133 is 9.316×10^{-3} rem-m^{-3}/Ci-sec. A puff release of the maximum WGDT inventory allowed by Technical Specifications results in a whole body EAB dose less than 0.5 Rem.

14.4.3 Radioactive Liquid Release

Accidents in the auxiliary systems that could result in the release of waste liquids must necessarily involve the rupture or leaking of various pipelines, valves, tanks, and pumps.

All liquid processing components are located within the auxiliary building, fuel building, decontamination building, radwaste facility, and station yard area. Any liquid leakage or release from these components is collected in sumps and pumped to the liquid waste disposal systems (Section 11.2.3) or flows directly to the vent and drain system (Section 9.7). The auxiliary building and fuel building are of Class I design. The below ground levels of the radwaste facility are seismically designed to the requirements of RG 1.143.

The boron recovery tanks are located in the station yard area in separately diked enclosures, each of which is of sufficient capacity to retain the total liquid volume resulting from the rupture of one boron recovery tank without any overflow to areas outside the enclosure. The collected liquid is pumped either to the unruptured boron recovery tanks or to the liquid waste disposal systems. The diked enclosure is of Class I design.

Piping running between the auxiliary building and the reactor containment, between the auxiliary and fuel buildings, between the fuel building and the tanks in the yard area, and between the auxiliary building and the radwaste facility is situated below grade in concrete trenches or in special piping conduits. Liquids spilled or released from such piping are collected in sumps and pumped into the liquid waste disposal system. Accordingly, a release of waste liquids would be contained within the station and would not result in an uncontrolled release to the environment.

14.4 REFERENCES

1. Letter from C. M. Stallings, Vepco, to V. Stello, NRC, Subject: *Movement of Heavy Loads Near Spent Fuel,* dated October 9, 1978.
2. Letters from B. C. Buckley and L. B. Engle (U. S. NRC) to W. L. Stewart (Virginia Electric and Power Company), *Surry, Units 1 and 2, and North Anna, Units 1 and 2 - Removal of 45,000 MWD/MTU Batch Average Burnup Restriction (TAC Nos. M87767, M87768, M87812, and M87813)*, December 14, 1993 and April 20, 1994.
3. *Extended Burnup Evaluation of Westinghouse Fuel*, Westinghouse Electric Corporation, WCAP-10125-P-A, December 1985.
4. D. A. Walker, et al., *Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors*, NUREG/CR-5009, PNL-6258, February 1988.
5. Letter from R. H. Leasburg, Vepco, to H. R. Denton, NRC, Subject: Amendment to Operating Licenses DPR-32 and DPR-37, Surry Power Station Unit Nos. 1 and 2. Proposed Technical Specification Changes, dated September 23, 1982 (Serial No. 543).
6. Letter from R. H. Leasburg, Vepco, to H. R. Denton, NRC, Subject: Supplemental Information for Proposed Operating License Amendment, dated January 17, 1983 (Serial No. 543A).
7. Letter from J. D. Neighbors (NRC) to W. L. Stewart (Virginia Electric and Power Company) Serial No. 131, March 4, 1983.
8. Letter from Chandu P. Patel (NRC) to W. L. Stewart (Virginia Electric and Power Company) *Approval of increase the maximum allowable k-effective during refueling*, April 1986.
9. *RADTRAD-NAI*, Release Version 1.2(QA), Zachry Nuclear Engineering, Inc., Richland, Washington.
10. NUREG/CR-2858, *PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations*, USNRC, 1982.
11. NUREG/CR-6331, Rev. 1, *Atmospheric Relative Concentrations in Building Wakes, ARCON96*, USNRC, 1997.
12. U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, *Standard Review Plan*, NUREG-0800, Revision 2, July 1981.
13. U.S. Nuclear Regulatory Commission Regulatory Guide 1.183, *Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors*, July 2000.
14. U.S. Nuclear Regulatory Commission, Office of Standards Development, *Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere*

*Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plan*ts, Regulatory Guide 1.52, Revision 2, March 1978.

15. Letter from W. L. Stewart (Virginia Power) to U. S. Nuclear Regulatory Commission, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Control Room Habitability, Operator Dose Assessment*, Serial Number 89-381, June 1989.

16. Letter from C. M. Stalling (Virginia Power) to U. S. Nuclear Regulatory Commission, *Response to Request for Additional Information*, Serial No. 045A/020177, May 1977.

17. Deleted

18. Letter from K. Cotton-Gross (NRC) to D. Stoddard, "*Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendment Nos. 295 and 295 to Adopt TSTF-490, Revision 0, and Update Alternative Source Term Analyses (EPID L-2018-LLA-0068),* June 12, 2019.

19. Letter from G.T. Bischof (Virginia Electric and Power Company) to U.S. Nuclear Regulatory Commission, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Proposed Increase In The Lead Rod Average Burnup Limit*, Serial No. 07-0024, March 6, 2007.

20. Letter from S.P. Lingam (NRC) to D.A. Christian (Dominion), "*Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Increase in the Lead Rod Average Burnup Limit (TAC Nos. MD4716 and MD4717)*," Serial No. 07-0854, December 19, 2007.

21. Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding the Use of Optimized ZIRLO™ Fuel Rod Cladding (TAC Nos. ME3343 and ME3344)*, Serial No. 10-669, December 22, 2010; as amended by Letter from K. Cotton (NRC) to D. A. Heacock (Dominion), *Surry Power Station, Unit Nos. 1 and 2, Issuance of Corrections to Amendments Regarding the Use of Optimized ZIRLO™ Fuel Rod Cladding (TAC Nos. ME3343 and ME3344)*, Serial No. 10-755, December 23, 2010.

22. Calculation CE-14247.01-NMB-194-FB, *Fuel Cask Drop Analysis for the NUHOMS EOS TC125 Cask System,* January 2021.

Table 14.4-1
ACTIVITY RELEASED TO THE CONTAINMENT OR FUEL BUILDING

Isotope	Activity Released (Ci)
I-130	1.536E-02
I-131	2.176E+02
I-132	2.075E+02
I-133	1.431E+01
I-135	9.721E-03
Kr-85	3.133E+03
Kr-88	1.095E-06
Kr-83m	9.875E-09
Kr-85m	3.041E-03
Xe-133	8.309E+04
Xe-135	1.664E+02
Xe-131m	7.496E+02
Xe-133m	1.539E+03
Xe-135m	5.081E-01

Table 14.4-2
ATMOSPHERIC DISPERSION FACTORS (χ/Qs) FOR OFFSITE CALCULATIONS

Receptor	Time Period	χ/Q value
EAB	0-2 hr	1.02E-03
LPZ	0-8 hr	5.66E-05
	8-24 hr	3.84E-05
	24-96 hr	1.66E-05
	96-720 hr	4.95E-06

Table 14.4-3
ATMOSPHERIC DISPERSION FACTORS (χ/Qs) FOR CONTROL ROOM CALCULATIONS

	Normal Intake		Emergency Intake	
Time Period	Containment Release χ/Q Value [ab]	Fuel Building Release χ/Q Value [ac]	Containment Release χ/Q Value [a]	Fuel Building & Release χ/Q Value [c]
0-2 hours	2.67E-03	8.47E-04	9.03E-04	6.55E-04
2-8 hours			6.83E-04	4.93E-04
8-24 hours			2.90E-04	2.03E-04
24-96 hours			2.05E-04	1.44E-04
96-720 hours			1.56E-04	1.08E-04

a. In this AST model, it is assumed the radioactivity reaches the control room before manual isolation of the control room takes place. Thus, normal control room intake χ/Q values need to be used during this time.

b. A release from containment uses the χ/Q values for the West Louver, as this release point had the most conservative value, maximizing dose consequence for this case.

c. A release from the fuel building uses the χ/Q values for Vent #2, as this release point had the most conservative value, maximizing dose consequence for this case.

Table 14.4-4
CONTROL ROOM OCCUPANCY FACTORS

0-8 hours	1.0
8-24 hours	1.0
24-96 hours	0.6
96-720 hours	0.4

Table 14.4-5
FHA CONTROL ROOM AND OFFSITE DOSES[b]

	Control Room 30-day Dose (REM TEDE)	EAB Worst 2-hour Dose (REM TEDE)	LPZ 30-day Dose (REM TEDE)
	2.7	3.2	0.2
Regulatory Guideline Value [a]	5.0	6.3	6.3

a. 10 CFR Part 50.67 establishes TEDE dose limits for the EAB, the outer boundary of the LPZ, and for the control room for use with the alternate source term. The specified offsite dose limits are stated for evaluating reactor accidents of exceedingly low probability of occurrence and low risk of public exposure to radiation, e.g., a large-break LOCA. For events with a higher probability of occurrence, e.g., FHA postulated EAB and LPZ doses should not exceed the limits established in RG 1.183. The 10 CFR 50.67 control room criterion applies to all accidents.
b. Composite results from the limiting or worst case containment and fuel building releases.

Table 14.4-6
MAXIMUM VOLUME CONTROL TANK NOBLE GAS CONCENTRATION IN VAPOR PHASE WITH SMALL CLADDING DEFECTS IN ONE PERCENT OF THE FUEL RODS

Isotope	Vapor Phase Activity Concentration μCi/gm
Kr-85	94.4
Kr-85m	12.6
Kr-87	1.3
Kr-88	15.4
Xe-133	2838.3
Xe-133m	41.2
Xe-135	92.3
Xe-135m	0.003
Xe-138	0.001

14.5 LOSS-OF-COOLANT ACCIDENT

14.5.1 Major Reactor Coolant System Pipe Ruptures (Large Break Loss-of-Coolant Accident)

14.5.1.1 General

The **FULL SPECTRUM™ LOCA** (**FSLOCA™**) Evaluation Model (EM) (Reference 5) was developed to address the full spectrum of loss-of-coolant accidents (LOCAs) which result from a postulated break in the reactor coolant system (RCS) of a pressurized water reactor (PWR). The break sizes considered in the Westinghouse FSLOCA EM include any break size in which break flow is beyond the capacity of the normal charging pumps, up to and including a double ended guillotine (DEG) rupture of an RCS cold leg with a break flow area equal to two times the pipe area, including what traditionally are defined as Small and Large Break LOCAs.

The break size spectrum is divided into two regions. Region I includes breaks that are typically defined as small-break LOCAs (SBLOCAs). The Region II includes break sizes that are typically defined as large-break LOCAs (LBLOCAs). The Region II analysis simulations only include breaks above 1.0 ft^2 break area and provide coverage to a maximum size of a DEG break. Only the Region II (LBLOCA) analysis was performed for this application of the FSLOCA EM. A Region I (SBLOCA) analysis was not performed.

The FSLOCA EM explicitly considers the effects of fuel pellet thermal conductivity degradation (TCD) and other burnup-related effects by initializing fuel rod conditions to fuel rod performance data input generated by the PAD5 code (Reference 4), which explicitly models TCD and is benchmarked to high burnup data. The fuel pellet thermal conductivity model in the WCOBRA/TRAC-TF2 code used in the FSLOCA EM explicitly accounts for pellet thermal conductivity degradation.

Three of the Title 10 of the Code of Federal Regulations (CFR) 50.46 criteria (peak cladding temperature (PCT), maximum local oxidation (MLO), and core-wide oxidation (CWO)) are considered directly in the FSLOCA EM. A high probability statement is developed for the PCT, MLO, and CWO that is needed to demonstrate compliance with 10 CFR 50.46 acceptance criteria (b)(1), (b)(2), and (b)(3) (Reference 62) when employing realistic methods to account for uncertainty. The MLO is defined as the sum of pre-transient corrosion and transient oxidation consistent with the position in Information Notice 98-29 (Reference 63). The coolable geometry acceptance criterion, 10 CFR 50.46 (b)(4), is met by compliance with acceptance criteria (b)(1), (b)(2), and (b)(3), and demonstrating that fuel assembly grid deformation due to combined seismic and LOCA loads does not extend to the in-board fuel assemblies, thus ensuring that a coolable geometry is maintained.

The FSLOCA EM has been generically approved by the Nuclear Regulatory Commission (NRC) for Westinghouse 3-loop and 4-loop plants with cold leg Emergency Core Cooling System

(ECCS) injection (Reference 5). Since Surry Units 1 and 2 are Westinghouse designed 3-loop plants with cold leg ECCS injection, the approved method is applicable.

This section summarizes the application of the Westinghouse FSLOCA EM to Surry Units 1 and 2. The application of the FSLOCA EM to Surry Units 1 and 2 is consistent with the NRC-approved methodology (Reference 5), with the corrections and changes reported in Reference 64 pursuant to 10 CFR 50.46, with the exception of only including an analysis for Region II. After completion of the analysis for Surry Units 1 and 2, two errors were discovered in the WCOBRA/TRAC-TF2 code. The first error was regarding the calculation of radiation heat transfer to liquid, which could be incorrectly calculated under certain conditions. The second error was regarding vapor temperature resetting, where under certain conditions the vapor temperature could incorrectly be reset to the saturation temperature for heat transfer calculations. These errors were found to have negligible impact on the FSLOCA EM analysis results as described in Reference 68.

An additional error regarding the gamma energy redistribution multiplier was identified after completion of the analysis for Surry Units 1 and 2. The treatment for the uncertainty in the gamma energy redistribution is discussed on pages 29-75 and 29-76 of Reference 5, and the equation for the assumed increase in hot rod and assembly relative power is presented on page 29-76. The power increase in the hot rod and hot assembly due to energy redistribution in the application of the FSLOCA EM to Surry Units 1 and 2 was calculated incorrectly. This error resulted in a 0% to 5% deficiency in the modeled hot rod and hot assembly rod linear heat rates on a run-specific basis, depending on the as-sampled value for the multiplier uncertainty. The effect of the error correction was evaluated against the application of the FSLOCA EM to Surry Units 1 and 2.

The error correction has only a limited impact on the power modeled for a single assembly in the core. As such, the error correction has a negligible impact on the system thermal-hydraulic response during the postulated LOCA. For the Region II analysis, parametric PWR sensitivity studies, derived from a subset of uncertainty analysis simulations covering various design features and fuel arrays, were examined to determine the sensitivity of the analysis results to the error correction. The PCT impact from the error correction was found to be different for the transient phases (i.e., blowdown versus reflood) based on the PWR sensitivity studies and existing power distribution sensitivity studies. Based on the results from the PWR sensitivity studies, the correction of the error is estimated to increase the Region II analysis PCT by 31°F, leading to an analysis result of 1848° for the Region II analysis assuming loss-of- offsite power and 1875 °F for the Region II analysis assuming offsite power available. All of the analysis results, including the error correction, continue to demonstrate compliance with the 10 CFR 50.46 acceptance criteria.

The major plant parameter and analysis assumptions used in the Surry Units 1 and 2 analysis with the FSLOCA EM are provided in Tables 14.5-1, 14.5-2, 14.5-4 and 14.5-5. Table 14.5-17 contains a sequence of events for the transient that produced the more limiting analysis PCT result relative to the offsite power assumption.

Subsequent to the completion of the analysis, revised pre-transient oxidation (PTO) data was generated which increased the PTO assumed in the analysis. Due to the substantial conservatisms in the fuel temperature and rod internal pressure methodology, there is no change to the analyzed fuel rod temperature and rod internal pressure data; therefore, there is no impact on the FSLOCA EM analysis transient results (including PCT). However, the updated PTO does impact the total MLO (transient plus pre-transient). The largest difference in upper bound oxidation relative to the data provided in the base LBLOCA analysis was used to conservatively estimate the impact of the revised PTO. The evaluation estimated an increase to the Region II analysis MLO of 2.26%. Analysis results continue to demonstrate compliance with the 10 CFR 50.46 acceptance criteria.

14.5.1.2 Identification of Cause and Accident Description

A LBLOCA is a hypothetical, design-basis accident that is considered in the sizing of ECCS components. The accident is initiated by an instantaneous rupture of a RCS pipe. The break type considered is either a double-ended guillotine, defined as a complete severance of the pipe resulting in unimpeded flow from either end, or a split break, defined as a partial tear. The break sizes considered vary from 1 ft^2 to two times the cold leg area. A break in the cold-leg piping between the reactor coolant pump and the reactor vessel inlet nozzle has been concluded to be the most limiting location for a large break in a PWR.

A revision to General Design Criterion 4 (GDC-4) was issued by the NRC effective May 12, 1986. In accordance with the revised rule, consideration of the dynamic effects of RCS pipe rupture may be eliminated as a design basis provided the “Leak Before Break” (LBB) analyses demonstrate that any flaw in the RCS primary loop piping which grew would become a through-wall crack with detectable leakage allowing shutdown of the plant long before a rupture would occur. LBB fracture mechanics analyses applicable to Surry have been accepted by the NRC and, in accordance with Amendment 108 to the Surry operating license, consideration of the dynamic effects of a LOCA is no longer part of the design basis. However, this change to the design basis does not affect the ECCS design basis or engineered safety feature system response. Therefore, the pipe rupture LOCA condition will remain as a design basis for safety related systems in the RCS and conservatively envelopes all other accidents.

Should a large break occur, rapid depressurization of the RCS to a pressure nearly equal to the containment pressure occurs in approximately 40 seconds, with a nearly complete loss of RCS inventory. Rapid voiding in the core shuts down the reactor. The SI system is actuated when the low pressurizer pressure setpoint (SI signal) is reached, and the accumulators inject upon RCS depressurization below the accumulator cover pressure, mitigating the consequences of the accident in two ways:

1. The borated water injection complements void formation in causing a rapid reduction in nuclear power to a residual level corresponding to fission product decay heat. The level of RCS mixed boron concentration is sufficient to ensure that the core remains subcritical for

short term post-LBLOCA considerations (long term core cooling considerations are discussed in Chapter 6 and Chapter 9). However, no credit is taken for the insertion of control rods to shut down the reactor in the large break analysis.

2. The injection of borated water provides core cooling and prevents excessive fuel rod cladding temperatures.

Before the break occurs, the reactor is assumed to be in a full power equilibrium condition, i.e., the heat generated in the core is being removed by the steam generators. At the beginning of the blowdown phase, the entire RCS contains sub-cooled liquid which transfers heat from the core by forced convection with some nucleate boiling. During blowdown, heat from fission product decay and stored energy in the fuel pellets continues to be transferred to the fuel rod cladding. After the break occurs, departure from nucleate boiling occurs.

The heat transfer between the RCS and the secondary system may be in either direction, based on the progression of the transient and the relative fluid temperatures. In the case of the large break LOCA, the primary pressure rapidly decreases below the secondary system pressure, and the steam generators become an additional heat source.

As the RCS pressure decreases to the accumulator gas cover pressure, injection of accumulator liquid into the cold leg begins. However, significant accumulator inventory is lost out of the break due to the phenomenon of emergency core cooling bypass. After the initial surge of accumulator inventory is lost out of the break, core bypass breaks down and the remaining accumulator liquid refills the lower portion of the reactor vessel. Reflood of the core and eventual quench of the fuel rods is accomplished by the injection of water from the refueling water storage tank (RWST).

The operation of the low head safety injection pumps supplies water for long term cooling. When the refueling water storage tank is nearly empty, long term cooling of the core is accomplished by switching to the recirculation mode of core cooling, in which the spilled borated water is drawn from the containment sump by the low head safety injection pumps and returned to the reactor vessel. The containment spray system and the recirculation spray system operate to return the containment environment to subatmostpheric pressure.

14.5.1.3 Method of Analysis

FULL SPECTRUM LOCA Evaluation Model Development

In 1988, the NRC Staff amended the requirements of 10 CFR 50.46 (Reference 62 and Reference 65) and Appendix K, "ECCS Evaluation Models," to permit the use of a realistic EM to analyze the performance of the ECCS during a hypothetical LOCA. Westinghouse's previously approved best-estimate LBLOCA EM is discussed in Reference 6. The EM is referred to as the Automated Statistical Treatment of Uncertainty Method (ASTRUM), and was developed following Regulatory Guide (RG) 1.157 (Reference 3).

When the FSLOCA EM was being developed, the NRC issued RG 1.203 (Reference 66) which expands on the principles of RG 1.157, while providing a more systematic approach to the development and assessment process of a PWR accident and safety analysis EM. Therefore, the development of the FSLOCA EM followed the Evaluation Model Development and Assessment Process (EMDAP), which is documented in RG 1.203. While RG 1.203 expands upon RG 1.157, there are certain aspects of RG 1.157 which are more detailed than RG 1.203; therefore, both RGs were used for the development of the FSLOCA EM.

WCOBRA/TRAC-TF2 COMPUTER CODE

The FSLOCA EM (Reference 5) uses the WCOBRA/TRAC-TF2 code to analyze the system thermal-hydraulic response for the full spectrum of break sizes. WCOBRA/TRAC-TF2 was created by combining a 1D module (TRAC-P) with a 3D module (based on Westinghouse modified COBRA-TF). The 1D and 3D modules include an explicit non-condensable gas transport equation. The use of TRAC-P allows for the extension of a two-fluid, six-equation formulation of the two-phase flow to the 1D loop components. This new code is WCOBRA/TRAC-TF2, where “TF2” is an identifier that reflects the use of a three-field (TF) formulation of the 3D module derived by COBRA-TF and a two-fluid (TF) formulation of the 1D module based on TRAC-P. This best-estimate computer code contains the following features:

1. Ability to model transient three-dimensional flows in different geometries inside the reactor vessel
2. Ability to model thermal and mechanical non-equilibrium between phases
3. Ability to mechanistically represent interfacial heat, mass, and momentum transfer in different flow regimes
4. Ability to represent important reactor and plant components such as fuel rods, steam generators (SGs), reactor coolant pumps (RCPs), etc.

A detailed assessment of the computer code WCOBRA/TRAC-TF2 was made through comparisons to experimental data. These assessments were used to develop quantitative estimates of the ability of the code to predict key physical phenomena for a LOCA. Modeling of a LOCA introduces additional uncertainties which are identified and quantified in the plant-specific analysis. The reactor vessel and loop noding scheme used in the FSLOCA EM is consistent with the noding scheme used for the experiment simulations that form the validation basis for the physical models in the code. Such noding choices have been justified by assessing the model against large and/or full-scale separate effect and integral effect test facility experiments (Reference 5).

14.5.1.4 Description of Representative Transient

A large-break LOCA transient can be divided into phases in which specific phenomena are occurring. A convenient way to divide the transient is in terms of the various heatup and cooldown phases that the fuel assemblies undergo. For each of these phases, specific phenomena and heat transfer regimes are important, as discussed below.

Blowdown – Critical Heat Flux (CHF) Phase

In this phase, the break flow is subcooled, the discharge rate of coolant from the break is high, the core flow reverses, the fuel rods go through departure from nucleate boiling (DNB), and the cladding rapidly heats up and the reactor is shut down due to the core voiding.

The regions of the RCS with the highest initial temperatures (upper core, upper plenum, and hot legs) begin to flash during this period. This phase is terminated when the water in the lower plenum and downcomer begins to flash. The mixture level swells and a saturated mixture is pushed into the core by the intact loop RCPs, still rotating in single-phase liquid. As the fluid in the cold leg reaches saturation conditions, the discharge flow rate at the break decreases significantly.

Blowdown – Upward Core Flow Phase

Heat transfer is increased as the two-phase mixture is pushed into the core. The break discharge rate is reduced because the fluid becomes saturated at the break. This phase ends as the lower plenum fluid mass is depleted, the fluid in the loops becomes two-phase, and the RCP head degrades.

Blowdown – Downward Core Flow Phase

The break flow begins to dominate and pulls flow down through the core as the RCP head degrades due to increased voiding, while liquid and entrained liquid flows also provide core cooling. Heat transfer in this period may be enhanced by liquid flow from the upper head. Once the system has depressurized to less than the accumulator cover pressure, the accumulators begin to inject cold water into the cold legs. During this period, due to steam upflow in the downcomer, a portion of the injected ECCS water is bypassed around the downcomer and sent out through the break. As the system pressure continues to decrease, the break flow and consequently the downward core flow are reduced. As the ECCS bypass phenomenon breaks down the break mass flow rate temporarily reduces to almost zero from 20 to 40 seconds after transient initiation due to the combination of the rapidly falling system pressure and the initial penetration of subcooled ECCS inventory. The system pressure approaches the containment pressure at the end of this last period of the blowdown phase.

During this phase, the core begins to heat up as the system approaches containment pressure, and the phase ends when the reactor vessel begins to refill with ECCS water.

Refill Phase

The core continues to heat up as the lower plenum refills with ECCS water. This phase is characterized by a rapid increase in fuel cladding temperature at all elevations due to the lack of liquid and steam flow in the core region. The water completely refills the lower plenum and the refill phase ends. As ECCS water enters the core at the end of the refill phase, the fuel rods in the lower core region begin to quench and liquid entrainment begins, resulting in increased fuel rod heat transfer.

Reflood Phase

During the early reflood phase, the accumulators begin to empty and nitrogen is discharged into the RCS. The nitrogen surge forces water into the core, which is then evaporated, causing system re-pressurization, illustrated by the temporary increase in RCS pressure, and a temporary reduction of pumped ECCS flow. During this time, core cooling may increase due to vapor generation and liquid entrainment, but conversely the early reflood pressure increase results in loss of mass out through the broken cold leg.

The pumped ECCS water aids in the filling of the downcomer throughout the reflood period. As the quench front progresses further into the core, the PCT elevation moves increasingly higher in the fuel assembly.

As the transient progresses, continued injection of pumped ECCS water refloods the core, effectively removes the reactor vessel metal mass stored energy and core decay heat, and leads to an increase in the reactor vessel fluid mass. Eventually the core fluid inventory increases enough that liquid entrainment is able to quench all the fuel assemblies in the core.

A second cladding heatup transient may occur due to boiling in the downcomer. The mixing of ECCS water with hot water and steam from the core, in addition to the continued heat transfer from the hot vessel and vessel metal, reduces the subcooling of ECCS water in the lower plenum and downcomer. The saturation temperature is dictated by the containment pressure. If the liquid temperature in the downcomer reaches saturation, subsequent heat transfer from the vessel and other structures will cause boiling and level swell in the downcomer. The downcomer liquid will spill out of the broken cold leg and reduce the driving head, which can reduce the reflood rate, causing a late reflood heatup at the upper core elevations.

14.5.1.5 Analysis Results

The Surry Units 1 and 2 Region II analysis was performed in accordance with the NRC-approved methodology in Reference 5, with exceptions identified in Section 14.5.1.1. The analysis was performed assuming both loss of offsite power (LOOP) and offsite power available (OPA), and the results of both the LOOP and OPA analyses are compared to the 10 CFR 50.46 acceptance criteria. The most limiting ECCS single failure of one ECCS train is assumed in the analysis as identified in Table 14.5-1. The results of the Surry Units 1 and 2 Region II LOOP and OPA uncertainty analyses are summarized in Table 14.5-3, and include the impact of the gamma energy redistribution error correction and the revised pre-transient oxidation data.

Table 14.5-17 contains a sequence of events for the transient that produced the more limiting analysis PCT result relative to the offsite power assumption. Figure 14.5-1 through Figure 14.5-14 illustrate the key response parameters for this transient. The containment pressure is calculated for each LOCA transient in the analysis using the COCO code (Reference 67 and Reference 7). The COCO containment code is integrated into the WCOBRA/TRAC-TF2 thermal-hydraulic code. The transient-specific mass and energy releases calculated by the thermal-hydraulic code at the end of each timestep are transferred to COCO. COCO then calculates the containment pressure based on the containment model (the inputs are summarized in Table 14.5-2 and Table 14.5-5) and the mass and energy releases, and transfers the pressure back to the thermal-hydraulic code as a boundary condition at the break, consistent with the methodology in Reference 5. The containment model for COCO calculates a conservatively low containment pressure, including the effects of all the installed pressure reducing systems and processes assuming all trains of containment spray are operable. The containment backpressure for the transient that produced the analysis PCT result is provided in Figure 14.5-8.

14.5.1.6 Compliance with 10 CFR 50.46

It must be demonstrated that there is a high level of probability that the following criteria in 10 CFR 50.46 are met:

(b)(1) The analysis PCT corresponds to a bounding estimate of the 95th percentile PCT at the 95-percent confidence level. Since the resulting PCT is less than 2,200°F, the analysis with the FSLOCA EM confirms that 10 CFR 50.46 acceptance criterion (b)(1), i.e., “Peak Cladding Temperature does not exceed 2,200°F,” is satisfied.

The results are shown in Table 14.5-3 for Surry Units 1 and 2.

(b)(2) The analysis MLO corresponds to a bounding estimate of the 95th percentile MLO at the 95-percent confidence level. Since the resulting MLO is less than 17 percent when converting the time-at-temperature to an equivalent cladding reacted using the Baker-Just correlation and adding the pre-transient corrosion, the analysis confirms that 10 CFR

50.46 acceptance criterion (b)(2), i.e., “Maximum Local Oxidation of the cladding does not exceed 17 percent,” is satisfied.

The results are shown in Table 14.5-3 for Surry Units 1 and 2.

(b)(3) The analysis CWO corresponds to a bounding estimate of the 95th percentile CWO at the 95-percent confidence level. Since the resulting CWO is less than 1 percent, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(3), i.e., “Core-Wide Oxidation does not exceed 1 percent,” is satisfied.

A detailed CWO calculation takes advantage of the core power census that includes many lower power assemblies. Because there is significant margin to the regulatory limit, the CWO value may be conservatively chosen as that calculated for the limiting hot assembly rod. A detailed CWO calculation is therefore not needed because the outcome will always be less than the hot assembly rod.

The results are shown in Table 14.5-3 for Surry Units 1 and 2.

(b)(4) 10 CFR 50.46 acceptance criterion (b)(4) requires that the calculated changes in core geometry are such that the core remains in a coolable geometry.

This criterion is met by demonstrating compliance with criteria (b)(1), (b)(2), and (b)(3), and by assuring that fuel assembly grid deformation due to combined LOCA and seismic loads is specifically addressed. Criteria (b)(1), (b)(2), and (b)(3) have been met for Surry Units 1 and 2 as shown in Table 14.5-3.

It is discussed in Section 32.1 of the NRC-approved FSLOCA EM (Reference 5) that the effects of LOCA and seismic loads on the core geometry do not need to be considered unless fuel assembly grid deformation extends to inboard assemblies beyond the core periphery (i.e., deformation in a fuel assembly with no sides adjacent to the core baffle plates). Inboard grid deformation due to combined LOCA and seismic loads is not calculated to occur for Surry Units 1 and 2.

(b)(5) 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS.

Long-term cooling is dependent on the demonstration of the continued delivery of cooling water to the core. The actions that are currently in place to maintain long-term cooling are not impacted by the application of the NRCapproved FSLOCA EM (Reference 5).

Based on the analysis results for Region II presented in Table 14.5-3 for Surry Units 1 and 2, it is concluded that Surry Units 1 and 2 comply with the criteria in 10 CFR 50.46.

14.5.1.7 Post Analysis of Record Evaluations

In addition to the analyses presented in this section, evaluations and reanalyses may be performed as needed to address computer code errors and emergent issues, or to support plant changes. The issues or changes are evaluated, and the impact on the Peak Cladding Temperature (PCT) is determined. The resultant increase or decrease in PCT is applied to the analysis of record PCT. The PCT, including all penalties and benefits is presented in Table 14.5-6 for the large break LOCA. The current PCT is demonstrated to be less than the 10 CFR 50.46(b) requirement of 2200°F.

In addition, 10 CFR 50.46 requires that licensees assess and report the effect of changes to or errors in the evaluation model used in the large break LOCA analysis. These reports constitute addenda to the analysis of record provided in the UFSAR until the overall changes become significant as defined by 10 CFR 50.46. If the assessed changes or errors in the evaluation model results in significant changes in calculated PCT, a schedule for formal reanalysis or other action as needed to show compliance will be addressed in the report to the NRC.

Finally, the criteria of 10 CFR 50.46 requires that holders and users of the evaluation models establish a number of definitions and processes for assessing changes in the models or their use. Westinghouse, in consultation with the PWR Owner's Group (PWROG), has developed an approach for compliance with the reporting requirements. This approach is documented in WCAP-13451, Westinghouse Methodology for Implementation of 10 CFR 50.46 Reporting (Reference 30). Dominion provides the NRC with annual and 30-day reports, as applicable, for Surry Power Station. Dominion intends to provide future reports required by 10 CFR 50.46 consistent with the approach described in Reference 30.

14.5.2 Loss of Reactor Coolant From Small Ruptured Pipes or From Cracks in Large Pipes, Which Actuates Emergency Core Cooling System (Small Break Loss-of-Coolant Accident Analysis)

14.5.2.1 General

An analysis of the Emergency Core Cooling System (ECCS) performance for the postulated small-break LOCA (SBLOCA) has been performed in compliance with Appendix K to 10 CFR 50. The results of this analysis are in compliance with 10 CFR 50.46. The analysis was performed in accordance with the NRC-approved S-RELAP5 methodology described in Reference 26 as supplemented by Reference 27 and approved in Reference 61.

14.5.2.2 Identification of Causes and Accident Description

A LOCA can result from a rupture of the reactor coolant system (RCS) or of any line connected to that system up to the first isolation valve. Ruptures of small cross section will cause expulsion of the coolant at a rate that can be accommodated by the charging pumps. A spectrum of cold leg break sizes were analyzed with the S-RELAP5 computer code, ranging from 1.0 inches to 8.7 inches in diameter. A rupture in the reactor coolant system results in the discharge to the containment of reactor coolant and associated energy. The result of this discharge is a decrease in coolant pressure in the reactor coolant system and an increase in containment temperature and pressure. The reactor trip signal subsequently occurs when the pressurizer low pressure trip setpoint is reached. A safety injection system (SIS) signal is actuated when the pressurizer low-low pressure setpoint is reached, activating the high head safety injection pumps. The SIS actuation and subsequent activation of the Emergency Core Cooling System, which results from the SIS signal, assumes the most limiting single failure of ECCS equipment.

Before the break occurs, the unit is assumed to be in an equilibrium condition, (i.e., the heat generated in the core is being removed via the secondary system). In the small break LOCA, the blowdown phase of the small break occurs over a long time period. Thus for a small break LOCA, there are three characteristic stages: (1) a gradual blowdown in which the decrease in water level is checked by the inventory replenishment associated with safety injection, (2) core recovery, and (3) long-term recirculation. The heat transfer between the reactor coolant system and the secondary system may be in either direction, depending on the relative temperature. For the case of continued heat addition to the secondary side, the secondary side pressure increases and the main steam safety valves may actuate to reduce the pressure. Makeup to the secondary side is automatically provided by the auxiliary feedwater system. Coincident with the safety injection signal, normal feedwater flow is stopped by closing the main feedwater control valves and tripping the main feedwater pumps. Emergency feedwater flow is initiated by starting the auxiliary feedwater pumps. The secondary side flow aids in the reduction of RCS pressure. When the reactor coolant system depressurizes to approximately 600 psia, the accumulators begin to inject borated water into the reactor coolant loops. Reflecting the loss of offsite power assumption, the reactor coolant pumps are assumed to be tripped at the time of reactor trip, and the effects of pump coastdown are included in the blowdown analysis.

14.5.2.3 Analysis Assumptions

As required by Appendix K of 10 CFR 50, certain conservative assumptions were made for the Small Break LOCA-ECCS analysis. The assumptions pertain to the conditions of the reactor and associated safety system equipment at the time that the LOCA is assumed to occur and include such items as the core peaking factors, core decay heat, and the performance of the Emergency Core Cooling System. Table 14.5-12 presents the values assumed for several key parameters in this analysis. Assumptions and initial operating conditions that reflect the requirements of Appendix K to 10 CFR 50 have been used in this analysis. These assumptions include:

- The break is located in the cold leg between the pump discharge and the vessel inlet.
- Safety injection occurs both in the intact loops and the broken loop.
- Accumulator injection occurs both in the intact loops and the broken loop.
- 120% of 1971 ANS decay heat is assumed following reactor trip.
- Initial power is 2597 MWt, which is 102% of 2546 MWt (100.38% of 2587 MWt) to account for the calorimetric uncertainty
- 7% tube plugging in each steam generator.
- Safety injection system delivers borated water to the reactor coolant system 40 seconds after actuation of the SIS signal. The 40-second delay includes sufficient time to allow startup of the emergency diesel generators and loading of the charging pumps onto the emergency buses.
- Minimum assumed auxiliary feedwater flow is provided to three steam generators.

The following assumptions have been incorporated into the SBLOCA analysis described below to provide margin in key input parameters.

The analysis assumed a peak Heat Flux Hot Channel Factor, FQ(z), value of 2.50 and a peak Nuclear Enthalpy Hot Channel Factor, FΔh, value of 1.70, inclusive of uncertainties, and a K(z) equal to 1 for all core heights. K(z) is a multiplier on the allowable 3-D peaking factor FQ, and by nature cannot exceed 1.0. The power shape used is consistent with these technical specifications and was selected to yield limiting SBLOCA results. These values bound the current and anticipated power peaking limits.

The flow rates for the HHSI are provided by an engineering model of the HHSI subsystem that is based on the system configuration and measured data from the plant. This model includes allowances for imbalance between the separate injection lines, HHSI pump degradation, and instrument accuracy. The HHSI pump curves used in the model are based on the actual measured plant data for the installed HHSI pumps in each unit. For the calculated HHSI flows, it is assumed that the HHSI flow recirculation line is open. This is consistent with previous assumptions used to calculate HHSI flow rates versus RCS pressure for small break LOCAs. Other assumptions regarding HHSI system configuration, such as water levels and back pressures, are set to provide limiting conditions for the specified test condition. HHSI flow testing performed during refueling outages assesses the condition of the HHSI pumps to ensure that the actual system performance is bounded by the assumptions in the current analysis. Table 14.5-13 and Table 14.5-14 provide the HHSI and LHSI flow rates used in the break spectrum analysis.

The analysis assumes representative fuel design and material characteristics and is applicable to the Westinghouse 15x15 Upgrade fuel product.

14.5.2.4 Analysis of Effects and Consequences

14.5.2.4.1 Method of Analysis

The SBLOCA analysis is a Fuel-vendor Independent application of the NRC-approved S-RELAP5 EMF-2328 methodology described in Reference 26 as supplemented by Reference 27 and approved in Reference 61. The methodology incorporates the appropriate conservatisms, as prescribed by Appendix K of 10 CFR 50 (Reference 28) and is applicable to W- and CE-designed plants. The application analyzes a 15x15 fuel product with non-fuel related plant-specific details. The EMF-2328 SBLOCA evaluation model for event response of the primary and secondary systems and the hot fuel rod used in this analysis is based on the use of two computer codes:

1. The RODEX2-2A code was used to determine the burnup dependent initial fuel rod conditions for the system calculations.

2. The S-RELAP5 code was used to predict the thermal-hydraulic response of the primary and secondary sides of the reactor system and the hot rod response.

A complete spectrum of cold leg break sizes was considered, ranging from 1.0 inches in diameter to 8.7 inches in diameter. In addition, sensitivity studies were performed to consider delayed reactor coolant pump (RCP) trip, attached piping breaks, and different ECCS fluid temperatures. The results described in Section 14.5.2.4.2 are applicable to the current 15x15 fuel product with ZIRLO or Optimized ZIRLO cladding.

14.5.2.4.2 Results

The Surry break spectrum analysis for SBLOCA includes breaks of varying diameter up to 10% of the flow area for the cold leg. The limiting PCT from the break spectrum is 1673ºF. The maximum value from the break spectrum for the transient maximum local oxidation (MLO) is 1.43%. The transient MLO does not include the pre-transient oxidation which is dependent on cladding type. The maximum core wide oxidation (CWO) is less than 0.06%.

The limiting PCT case was determined to be the 2.6 inch break with a PCT of 1673ºF. The sequence of events is shown in Table 14.5-15. The transient progression is shown in Figure 14.5-15 through Figure 14.5-33:

- Cladding Temperature at the PCT Location: Figure 14.5-15
- Break Flow Rate: Figure Figure 14.5-16
- Break Void Fraction Figure 14.5-17
- System Pressures: Figure 14.5-18
- Reactor Power: Figure 14.5-19
- RCS and RV Masses: Figure 14.5-20
- Downcomer Level: Figure Figure 14.5-21
- Hot Assembly Collapsed Level:Figure 14.5-22
- Hot Assembly Mixture Level: Figure 14.5-23
- Cold Leg Mass Flow Rates: Figure 14.5-24
- HHSI Mass Flow Rates: Figure 14.5-25
- LHSI Mass Flow Rates:Figure 14.5-26
- Accumulator Mass Flow Rates: Figure 14.5-27
- Loop Seal Upside Collapsed Levels: Figure 14.5-28
- SG Upside Tube Collapsed Level: Figure 14.5-29
- Secondary Mass:Figure 14.5-30
- MFW Mass Flow Rates:Figure 14.5-31
- AFW Mass Flow Rates: Figure 14.5-32
- MSSV Mass Flow Rates: Figure 14.5-33

The ECCS must also cope with breaks in attached piping. The Surry plant has a separate line for the accumulator and the pumped SI injection connected to each cold leg. The high head and low head system share a common short length of pipe before joining to the cold leg. Both the accumulator and SI line break were analyzed. The accumulator line break resulted in a PCT of 1292ºF and a transient MLO of 0.06%. The SI line break resulted in a PCT of 934ºF and transient MLO of less than 0.01%. The results are less limiting than those of the break spectrum analysis.

14.5.2.5 Post Analysis of Record Evaluations

In addition to the analyses presented in this section, evaluations and reanalyses may be performed as needed to address computer code errors and emergent issues, or to support plant changes. The issues or changes are evaluated, and the impact on the PCT is determined. The resultant increase or decrease in PCT is applied to the analysis of record PCT. The PCTs, including all penalties and benefits, are presented in Table 14.5-16 for the small break LOCA. The resultant PCT is demonstrated to be less than the 10 CFR 50.46(b) requirement of 2200°F.

As discussed in Section 14.5.1.7, 10 CFR 50.46 requires that licensees assess and report the effect of changes to or errors in the evaluation models used in LOCA analyses. The requirements discussed in Section 14.5.1.7 are also applicable to the small break LOCA analysis.

14.5.2.5.0.1 Conclusions. The calculated peak clad temperature for the limiting 2.6-inch break is 1673°F, which is less than the 2200°F limit. The maximum transient local metal-water reaction for the limiting 2.5-inch break is 1.43%. Including pre-transient oxidation, the total local metal-water reaction is less than the embrittlement limit of 17%. The total core-wide metal-water reaction is less than the 1% limit. The results show that the clad temperature transient has peaked and sufficiently stabilized while the core is still amenable to cooling. Consequently, it is concluded that the Surry ECCS will be capable of mitigating the effects of a small break LOCA with a maximum F_Q of 2.50 and a $F\Delta h$ of 1.70, inclusive of uncertainties, at a thermal core power of 2597 MWt, with the current 15x15 fuel product.

An evaluation performed for a transition from 15 x 15 SIF with ZIRLO cladding to 15 x 15 Upgrade fuel with Optimized ZIRLO cladding concluded that there is no significant impact on the SBLOCA analysis results and all pertinent 10 CFR 50.46 acceptance criteria continue to be satisfied (see Section 14.5.2.5).

For the small break LOCA, the emergency core cooling system will thus meet the acceptance criteria as presented in 10 CFR 50.46, as follows:

1. The calculated peak fuel element clad temperature provides margin to the limit of 2200°F.
2. The amount of fuel element cladding that reacts chemically with water or steam does not exceed 1% of the total amount of Zircaloy in the reactor.
3. The clad temperature transient is terminated at a time when the core geometry is still amenable to cooling. The localized cladding oxidation limit of 17% is not exceeded.
4. The core remains amenable to cooling during and after the break.
5. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long-lived radioactivity remaining in the core.

14.5.3 Core and Internals Integrity Analysis

The methodology presented in Sections 14.5.3.1 through 14.5.3.4 has been replaced in part by the methodology of WCAP-9401. Also, the BLODWN-2 program has been replaced in part by the MULTIFLEX computer code. Refer to Section 14.5.3.3.4 for a description of the MULTIFLEX code and its use in blowdown and force models and the WCAP-9401 methodology.

14.5.3.1 Internals Evaluation

The forces exerted on the reactor internals and the core following a LOCA are computed by employing the BLODWN-2 digital computer program developed for the space-time-dependent analysis of multiloop PWR plants.

14.5.3.2 Design Criteria

Following a LOCA, the basic requirement is that the plant shall be shut down and cooled down in an orderly manner so that fuel cladding temperature is kept within the specified limits. This implies that the deformation of the reactor internals must be kept sufficiently small so that the core geometry remains substantially intact to allow core cooling and insertion of a sufficient number of control-rod assemblies.

After the break, the reduction in water density greatly reduces the reactivity of the core, thus shutting down the core independent of the control-rod assemblies. In other words, the core is shut down whether or not the control-rod assemblies are tripped. (The subsequent refilling of the core by the emergency core cooling system uses borated water to maintain the core in a subcritical state). Therefore, insertion of most of the control-rod assemblies gives further assurance of the ability to shut the unit down and keep it in a safe-shutdown condition. Note that the methodologies of Reference 45 and Reference 52 have been used to verify acceptability for crediting control rod insertion following a cold leg break in the assessment of long term core cooling.

Maximum allowable deflection limitations are established for those regions of the internals that are critical for unit shutdown. Allowable stress limits are adopted to ensure physical integrity of the components.

In the event of a sudden double-ended reactor coolant system pipe rupture[1] (complete severance in a few milliseconds), pressure waves are produced in the reactor, causing vertical and horizontal excitation of the components. A study has been made to analyze the response of the reactor vessel internal structures under these conditions.

14.5.3.3 Blowdown and Force Models

14.5.3.3.1 Blowdown Model

BLODWN-2 is a digital computer program used for calculation of local fluid pressure, flow, and density transients that occur in the reactor coolant system during a LOCA. This program applies to the subcooled, transition, and saturated two-phase blowdown regimes. This is in contrast to programs such as WHAM (Reference 9), which are applicable only to the subcooled region and which, due to their method of solution, could not be extended into the region in which large changes in the sonic velocities and fluid densities take place.

1. As discussed in Section 15.6.2, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop piping. However, pipe ruptures of reactor coolant branch lines are still postulated.

BLODWN-2 is based on the method of characteristics, wherein the resulting set of ordinary differential equations obtained from the laws of conservation of mass, momentum, and energy, are solved numerically using a fixed mesh in both space and time.

Although one-dimensional conversation laws are employed, the code can be applied to describe three-dimensional system geometries through the use of the equivalent piping networks. Such piping networks may contain any number of pipes or channels of various diameters, dead ends, branches (with up to six pipes connected to each branch), contractions, expansions, orifices, pumps, and free surfaces (such as in a pressurizer). System losses such as friction, contraction, expansion, etc., are considered.

14.5.3.3.2 Comparison With Experimental Data

BLODWN-2 predictions have been compared with data obtained by Phillips Petroleum Company from their loss-of-flow test (LOFT) semi-scale and 1/4-scale blowdown experiments.

An example of these comparisons is shown in Figure 14.5-75, which illustrates the pressure history in the blowdown pipe for the semi-scale test #522. This was a bottom blowdown test for the “Bettis Flask No. 1” geometry, with initial uniform fluid conditions of 1268 psia and 445°F. It can be seen that the BLODWN-2 digital computer program gives good agreement in both the subcooled and the saturated regimes.

14.5.3.3.3 Force Model

BLODWN-2 evaluates the pressure and velocity transients for a maximum of 2400 locations throughout the system. These pressure and velocity transients are stored as a permanent tape file and are made available to the program FORCE, which uses a detailed geometric description in evaluating the loading in reactor internals.

Each reactor component for which force calculations are required is designated as an element and assigned an element number. Forces acting upon each of the elements are calculated, summing the effects of:

1. The pressure differential across the element.
2. Flow stagnation on, and unrecovered orifice losses across, the element.
3. Friction losses along the element.

Input to the code, in addition to the BLODWN-2 pressure and velocity transients, includes the effective area of each element on which the force acts due to the pressure differential across the element, a coefficient to account for flow stagnation and unrecovered orifice losses, and the total area of the element along which the shear forces act.

14.5.3.3.4 Method of Blowdown Re-Analysis

Re-analysis of the blowdown forces on the reactor vessel and internals structures for Units 1 and 2, such as the one performed for the vessel head replacements and the control rod insertion analysis following a cold leg break (Reference 45), has made use of the MULTIFLEX (References 46 & 47) computer code, rather than BLODWN-2 described above, and the methodology of WCAP-9401 (Reference 48). MULTIFLEX is an extension of the BLODWN-2 code and includes mechanical structure models and their interactions with the thermal-hydraulic system. Both versions of the MULTIFLEX code share a common hydraulic modeling scheme, with the differences confined to a more realistic downcomer hydraulic network, and a more realistic core barrel structural model that accounts for non-linear boundary conditions and vessel motion. Generally, this improved modeling results in lower, more realistic, but still conservative hydraulic forces on the core barrel. The NRC staff has accepted (References 49, 50, & 53) the use of MULTIFLEX (including MULTIFLEX 3.0) for calculating the hydraulic forces on reactor vessel internals, including the reactor core (References 51 & 52). MULTIFLEX is used in the analysis to calculate the thermal-hydraulic transient (primarily transient pressures) within the reactor vessel. The re-analysis uses the FORCE2 computer code (described in Reference 46) to post process MULTIFLEX hydraulic transient results into vertical forces as described above for the FORCE code. Lateral forces are computed using the LATFORC code (described in Reference 46). The WCAP-9401 methodology utilizes a 3-dimensional structural model of the reactor vessel, internals, reactor core, and vessel support mechanism. LOCA forces acting on internals components are generated using the calculated transient pressures from the MULTIFLEX computer code and the FORCE2 and LATFORC codes. Horizontal and vertical responses are calculated simultaneously from the 3-dimensional model for both LOCA and seismic loading conditions.

14.5.3.4 Response of Reactor Internals to Blowdown Forces

14.5.3.4.1 Reactor Equipment System Model - LOCA Analysis

The response of reactor internals components due to an excitation produced by complete severance of a branch line pipe is analyzed. Assuming a pipe break occurs in a very short period of time of 1 millisecond, the rapid drop of pressure at the break produces a disturbance that propagates along the primary loop and excites the internal structures.

The LOCA break considered for Surry Units 1 and 2 consist of breaks located at the accumulator (ACC) line, pressurizer surge (PZR) line, and the residual heat removal (RHR) line. The LOCA hydraulic forcing functions (horizontal and vertical forces) that were used in the analyses were generated using MULTIFLEX 3.0 computer code described by Reference 47.

Mathematical Model of the Reactor Pressure Vessel (RPV) System

The mathematical model of the RPV system is a three-dimensional nonlinear finite element model, which represents the dynamic characteristics of the reactor vessel/internals/fuel in the six geometric degrees of freedom. The RPV system model was developed using the WECAN (Westinghouse Electric Computer Analysis) computer code. The WECAN finite element model consists of three concentric submodels connected by the nonlinear impact elements and stiffness matrices. The first submodel represents the reactor vessel shell and associated components. The reactor vessel is restrained by reactor vessel supports and by the attached primary coolant piping. The reactor vessel support system is represented by stiffness matrices.

The second submodel represents the reactor core barrel assembly (core barrel and thermal shield), lower support plate, tie plate, and secondary core support components. This submodel is physically located inside the first, and is connected to it by a stiffness matrix at the internals support ledge. Core barrel to vessel shell impact is represented by nonlinear elements at the core barrel flange, core barrel nozzle, and lower radial support locations.

The third and innermost submodel represents the upper support plate, guide tubes, support columns, upper and lower core plates, and the fuel. This submodel includes the specific properties of the Westinghouse 15 x 15 Upgraded fuel assemblies. The third submodel is connected to the first and second by a stiffness matrices and nonlinear elements.

The WECAN computer code, which is used to determine the response of the reactor vessel and its internals, is a general purpose finite element code. In the finite element approach, the structure is divided into a finite number of members or elements. The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformation, the element global matrices and arrays are then computed. Finally, the global element matrices and arrays are assembled into the global structural matrices and arrays, and used for dynamic solution of the differential equation of motion for the structure:

$$[M]\{\ddot{U}\}+[D]\{\dot{U}\}+[K]\{U\}=\{F\}$$

Where,

$[M]$ = Globalinertia matrix
$[D]$ = Global damping matrix
$[K]$ = Global stiffness matrix
$\{\ddot{U}\}$ = Acceleration array
$\{\dot{U}\}$ = Velocity array
$\{U\}$ = Displacement array
$\{F\}$ = Force array, including impact, thrust forces, hydraulic forces, constraints and weight.

WECAN solves the above equation using the nonlinear modal superposition theory. An initial computer run is made to calculate the eigenvalues (frequencies) and eigenvectors (mode shapes) for the mathematical model. This information is stored, and is used in a subsequent computer run which solves the equation. The first time step performs a static solution of the equation to determine the initial displacements of the structure due to deadweight and normal operating hydraulic forces. After the initial time step, WECAN calculates the dynamic solution of the equation. Time-history nodal displacements and impact forces are stored for postprocessing.

The following typical discrete elements from the WECAN finite element library are used to represent the reactor vessel and internals components:

- Three-dimensional elastic pipe
- Three-dimensional mass with rotary inertia
- Three-dimensional beam
- Three-dimensional linear spring
- Concentric impact element
- Linear impact element
- 6 x 6 stiffness matrix
- 18 Card stiffness matrix
- 18 Card Mass matrix
- Three-dimensional friction element

During performance of analysis Westinghouse converted the reactor equipment system model (RESM) from WECAN to ANSYS as follows:

The reactor equipment system model (RESM) is used to determine the dynamic response of the RPV and internal system when subjected to loss -of-coolant accident (LOCA) excitations and seismic excitations. The mathematical model of the RPV system is a three-dimensional non-linear finite element model that represents the dynamic characteristics of the reactor vessel/ internals/ fuel in the six geometric degrees of freedom.

For the upflow conversion, the RPV system model was developed using ANSYS computer code. The ANSYS finite element model consists of three concentric structural sub-models connected by non-linear impact elements and stiffness matrices.

The first sub-model represents the reactor vessel shell and associated components. The RPV is restrained by reactor vessel supports and by the attached primary coolant piping. The reactor support system is represented by stiffness matrices.

The second sub-model represents the reactor core barrel assembly (core barrel and thermal shield), lower support plate, tie plates, and secondary core support components. The sub-model is physically located inside the first and is connected to it by a stiffness matrix at the internal support ledge. Core barrel to vessel shell impact is represented by nonlinear elements at core barrel flange, core barrel nozzle and lower radial key support locations.

The third sub-model represents the upper support plate, guide tubes, support columns, upper and lower core plates and fuel. The sub-model includes the specific properties of the Westinghouse 15x15 upgrade fuel. The third sub-model is connected to the first and second sub-models by stiffness matrices and non-linear elements.

The following typical discrete elements from ANSYS finite element library are used to represent the reactor vessel and internal components:

- Three-dimensional elastic pipe
- Three dimensional mass and rotary inertia
- Three dimensional beam
- Three-dimensional linear spring
- Concentric impact element
- Linear impact element
- 6x6 card stiffness matrix
- 18-card stiffness matrix
- 18-card mass matrix
- Three-dimensional friction element

The RESM analyses are completed using ANSYS parametric macro and the results are post processed to generate the following:

- Component interface loads (force in nonlinear elements)
- Core plate motions
- Vessel motions
- Closure head acceleration response spectra

The LOCA loads were generated considering the combination of upflow conversion and implementation of ELBB resulting in lower magnitude LOCA loads.

Analytical Methods

The RPV system finite element model as described above was used to perform the LOCA analysis. Following a postulated LOCA pipe rupture, forces are imposed on the reactor vessel and its internals. These forces result from the release of the pressurized primary system coolant. The release of the pressurized coolant results in the traveling depressurization waves in the primary system. These depressurization waves are characterized by a wavefront with low pressure on one side and high pressure on the other. The wavefront translates and reflects throughout the primary system until the system is completely depressurized. The rapid depressurization results in transient hydraulic loads on the mechanical equipment of the system.

The LOCA loads applied to the reactor vessel system consist of (a) reactor internal hydraulic loads (vertical and horizontal), and (b) reactor coolant loop mechanical loads. All of the loads are calculated individually and combined in a time-history manner.

RPV Internal Hydraulic Loads -

Depressurization waves propagate from the postulated break location into the reactor vessel through either a hot leg or a cold leg nozzle.

After a postulated break in cold leg, the depressurization path for the waves entering the reactor vessel is through the nozzle into the region between the core barrel and reactor vessel. This region is called the downcomer annulus. The initial wares propagate up, around, and down the downcomer annulus, then up through the region circumferentially enclosed by the core barrel; that is the fuel the region.

The region of the downcomer annulus close to the break depressurizes rapidly; however, because of the restricted flow areas and finite wave speed (approximately 3,000 feet per second), the opposite side of the core barrel remains at a high pressure. This results in a net horizontal force on the core barrel and reactor pressure vessel. As the depressurization wave propagates around the downcomer annulus and up through the core, the barrel differential pressure reduces, and similarly, the resulting hydraulic forces drop.

In the case of the postulated break in the hot leg, the waves follow a dissimilar depressurization path, passing through the outlet nozzle and directly into the upper internals region, depressurizing the core and entering the downcomer annulus from the bottom exit of the core barrel. Thus, after a break in the hot leg, the downcomer annulus would depressurize with very little difference in pressure across the outside of the diameter of the core barrel.

A hot leg break produces less horizontal force because the depressurization wave travels directly to the inside of the core barrel (so that the downcomer annulus is not directly involved) and internal differential pressures are not as large as for a cold leg break. Since the differential pressure is less for a hot leg break, the downcomer annulus would be depressurized with very little difference in the pressure across the outside diameter of the core barrel.

Reference 47 describes how the MULTIFLEX computer code calculates the hydraulic transients within the entire primary coolant system. It considers subcooled, transition, and two-phase (saturated) blowdown regimes. The MULTIFLEX program employs the method of characteristics to solve the conservation laws, and assumes one-dimensionality of flow and homogeneity of the liquid-vapor mixture.

The MULTIFLEX code considers a coupled fluid structure interaction by accounting for the deflection of the constraining boundaries, which are represented by separate spring mass oscillator systems. A beam model of the core support barrel has been developed from the structural properties of the core barrel; in this model, the cylindrical barrel is vertically divided into various segments and the pressure as well as the wall motions are projected onto the plane parallel in the broken inlet nozzle. Horizontally, the barrel is divided into 10 segments; each segment consists of three separate walls. The spatial pressure variation at each time step is transformed into 10 horizontal forces, which act on the 10 mass points of the beam model. Each flexible wall bounded on either side by a hydraulic flow path. The motion of the flexible walls is determined by solving the global equations of motion for the masses representing the forced vibration of an undamped beam.

Reactor Coolant Loop Mechanical Loads

The reactor coolant loop mechanical loads are applied to the RPV nozzles by the primary coolant loop piping. The loop mechanical loads results from the release of normal operation forces present in the pipe prior to the separation as well as transient hydraulic forces in the reactor coolant system. The magnitudes of the loop release forces are determined by performing a reactor coolant loop analysis for normal operating loads (pressure, thermal, and deadweight). The loads existing in the pipe at the postulated break location are calculated and are “released” at the initiation of the LOCA transient by application of the loads to the broken piping ends. These forces are applied with a ramp time of 1 millisecond because of the assumed instantaneous break opening time. For breaks in the branch lines, the force applied at the reactor vessel would be insignificant. The restraints on the main coolant piping would eliminate any force to the reactor vessel caused by a break in the branch line.

Results of the Analysis

The severity of a postulated break in a reactor vessel is related to three factors: the distance from the reactor vessel to the break location, the break opening area, and the break opening time. The nature of the decompression following a LOCA, as controlled by the internals structural configuration previously discussed, results in larger reactor internal hydraulic forces pipe breaks in the cold leg than in the hot leg (for breaks of similar area and distance from the RPV). Pipe breaks farther away from the reactor vessel are less severe because the pressure wave attenuates as it propagates toward the reactor vessel. The LOCA hydraulic and mechanical loads described in the previous sections were applied to the WECAN model of the reactor pressure vessel system.

The results of LOCA analysis include time-history displacements and nonlinear impact forces for all major components. The time-history displacements of upper core plate, lower core plate, and core barrel at the upper core plate elevation are provided as input for the reactor core evaluations. The impact forces calculated at the vessel-internals interfaces are used to evaluate the structural integrity of the reactor vessel and its internals. Using appropriate postprocessors, component linear forces are also calculated.

ANSYS: Westinghouse upgraded/ refined computer analysis by converting the Reactor Equipment System Model (RESM) from WECAN computer code to ANSYS computer code during the upflow conversion analysis. See Section 14.5.3.4.1 for detailed description of the model.

RPV Sliding Foot Support Analysis

For analysis of the RPV sliding foot supports for both Unit 1 and 2, an NRC approved methodology (References 55, 56, & 57) is used which credits increased break opening times for RCS branch line breaks in order to better characterize LOCA forces acting on the sliding foot supports. Using these alternatively developed LOCA forces, combined with existing design basis loads, the RPV sliding foot supports are capable of supporting postulated design basis loads without the need for crediting any of the twenty cap screws between the socket plate and the nozzle pad. The alternative methodology approach utilized is described in more detail below.

For purposes of lowering LOCA forces acting on the RPV sliding foot supports, increased break opening times (BOT) shown in Table 14.5-18 are developed using an NRC approved methodology described in References 55, 56, & 57. Crediting these increased BOTs, a new thermal-hydraulic model coded in AREVAs CRAFT2 software (Reference 58) is used to develop pressure and force time-histories corresponding to postulated breaks at the following RCS branch line connections: [1] 14” residual heat removal (RHR) line (Loop 1 Hot Leg); [2] 12” safety injection (SI) line (Loop 1 Cold Leg); and [3] 12” pressurizer surge (PZR) line (Loop 3 Hot Leg). AREVAs CRAFT2 software (Reference 58) is a thermal hydraulic code that is functionally equivalent to Westinghouse’s MULTIFLEX software. Asymmetric cavity pressure (ACP) force time histories acting on the reactor coolant pumps and steam generators are also developed. AREVAs BWHIST software (Reference 59) is used to develop LOCA force time histories from the pressure time histories developed from the CRAFT2 thermal-hydraulic model and the ACP analysis. AREVAs BWHIST program (Reference 59) is used to develop LOCA force time histories from the pressure time histories developed from the CRAFT2 thermal-hydraulic model and the ACP analysis. AREVAs BWHIST program (Reference 59) is a postprocessor of CRAFT2 that converts the CRAFT2 results to input for AREVAs BWSPAN structural analysis software (Reference 60), which is functionally equivalent to Westinghouse’s WECAN software. BWSPAN is used to model the RPV and three reactor coolant loops (including large bore piping, reactor coolant pumps, steam generators, and supports) and LOCA loads at the RPV sliding foot support (and at other major RCL equipment supports) are generated. These revised LOCA forces are combined with other design basis loads and the RPV support is re-evaluated in order to demonstrate that the aforementioned twenty cap screws are no longer required to be credited. Note that LOCA reaction forces developed for major RCL equipment supports (i.e., steam generator and RCP supports) are checked against design basis limitations for these supports to evaluate acceptability for the increased BOT and revised modeling approach. However, the Westinghouse-developed LOCA forces (using the 1 ms BOT) are still valid for the design of the major RCL equipment supports.

ANSYS: Westinghouse upgraded/ refined computer analysis by converting the Reactor Equipment System Model (RESM) from WECAN computer code to ANSYS computer code during the upflow conversion analysis. See Section 14.5.3.4.1 for detailed description of the model.

14.5.3.4.2 Reactor Equipment System Model Seismic Analysis

Nonlinear dynamic seismic analysis of the RPV system (reactor pressure vessel, internals, and fuel) includes the development of the system finite element model and the synthesized time-history accelerations.

The basic mathematical model for seismic analysis is essentially similar to the LOCA model except in that the seismic model includes the hydrodynamic mass matrices in the vessel/barrel annulus to account for the fluid-interactions. The RPV system finite element model for the nonlinear time-history seismic analysis consists of three concentric structural submodels connected by nonlinear impact elements and linear stiffness matrices. The first submodel represents the reactor vessel shell and its associated components. The reactor vessel is restrained by reactor vessel support system in the system finite element model was represented by stiffness matrices.

The second submodel represents the reactor core barrel, thermal shield, lower support plate, tie plates, and the secondary core support components. These submodels are physically located inside the first, and are connected to them by stiffness matrices at the vessel-internals interfaces. Core barrel to reactor vessel shell impact is represented by nonlinear elements at the core barrel flange, upper support plate flange, core barrel outlet nozzles, and the lower radial restraints.

The third and innermost submodel represents the upper support plate assembly consisting of guide tubes, upper support columns, upper and lower core plates, and the fuel. The fuel assembly simplified structural model incorporated in to the RPV system model. The third submodel is connected to the first and second submodel by stiffness matrices and nonlinear elements.

As mentioned earlier, fluid-structure or hydroelastic interaction is included in the reactor pressure vessel model for seismic evaluations. The horizontal hydroelastic interaction is significant in the cylindrical fluid flow region between the core barrel and the reactor vessel annulus. Mass matrices with off-diagonal terms (horizontal degrees of freedom only) attach between nodes on the core barrel, thermal shield, and the reactor vessel. The diagonal terms of the mass matrix are similar to the lumping of water masses to the vessel shell, thermal shield, and core barrel. The off-diagonal terms reflect the fact that all of the water mass does not participate when there is no relative motion of the vessel and the core barrel. It should be pointed out that the hydrodynamic mass matrix has no artificial virtual mass effect and is derived in a straight-forward, quantitative manner.

The matrices are a function of the properties of two cylinders with the fluid in the cylindrical annulus, specifically, inside and outside radius of the annulus, density of the fluid and length of the cylinders. Vertical segmentation of the reactor vessel and the core barrel allows inclusion of radial variations along their heights and approximates the effects of beam mode deformation. These mass matrices were inserted between the selected nodes on the core barrel, thermal shield, and the reactor vessel.

The seismic evaluations are performed by including the effects of simultaneous application of time-history accelerations in three orthogonal directions. The WECAN computer code, which is used to determine the response of the reactor vessel and its internals, is a general purpose finite element code. In the finite element approach, the structure is divided into a finite number of discrete members or elements. The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformations, the element global matrices and arrays are assembled into global structural matrices and arrays, and used for dynamic solution of the system equations.

ANSYS: Westinghouse upgraded/ refined computer analysis by converting the Reactor Equipment System Model (RESM) from WECAN computer code to ANSYS computer code during the upflow conversion analysis. See Section 14.5.3.4.1 for detailed description of the model.

14.5.3.4.3 Allowable Deflection and Stability Criteria

14.5.3.4.3.1 Fuel Assemblies. The limitations for this case are related to the stability of the thimbles in the upper end. The upper end of the thimbles cannot experience stresses above the buckling compressive stresses, because any buckling of the upper end of the thimbles distorts the guide line and could affect the free fall of the control-rod assembly. The buckling stress for the thimbles is 62,300 psi, and the yield stress is 62,500 psi.

14.5.3.4.3.2 Upper Core Package. The local deformation of the upper core plate where a guide tube is located shall be less than 0.100 inch. This deformation causes the plate to contact the guide tube, since the clearance between plate and guide tube is 0.1 inch. This limit prevents the guide tubes from being put in compression.

For a plate local deformation of 0.150 inch, the guide tube is compressed and deformed transversely to the established upper limit, and consequently the value of 0.150 inch. is adopted as the maximum core plate local deformation, with an allowable of 0.100 inch.

14.5.3.4.3.3 Upper Core Barrel. The upper barrel deformation has the following limits:

1. To ensure reactor trip and to avoid disturbing the control-rod assembly guide structure, the barrel cannot interfere with any guide tubes. This condition requires a stability check to ensure that the barrel does not buckle under the accident loads. The minimum distance between guide tube and barrel is 9 inches. This value is adopted as the limit above which “no loss of function” can no longer be guaranteed. An allowable deflection of 4.5 inches has been selected.

2. To ensure core cooling, the outward movement of the upper barrel must be such that the inlet flow from the unbroken cold legs is not impaired. From this condition an outward barrel deflection of 6 inches in front of the inlet nozzle has been established as the no-loss-of-function value. An allowable deflection of 3 inches has been selected.

14.5.3.4.3.4 Control-Rod Assembly Guide Tubes. The guide tubes in the upper core support package housing control-rod assembly required for unit shutdown have the following deflection limit: the maximum horizontal deflection of a beam should not exceed 1.75 inches over the length of the guide tube. An allowable distortion of 1.0 inch has been selected.

14.5.3.4.3.5 Allowable Stress Criteria. The allowable stress criteria fall into two categories depending on the nature of the stress state (membrane or bending). A direct or membrane state of stress has a uniform stress distribution over the cross section. The allowable (maximum) membrane or direct stress is taken to be equal to the stress corresponding to 20% of the uniform material strain or the yield strength, whichever is higher. For unirradiated type 304 stainless steel at operating temperature, the stress corresponding to 20% of the uniform strain is 39,500 psi. For irradiated type 304 stainless steel, the stress limit is higher.

For a bending state of stress, the strain is linearly distributed over a cross section. The average strain value is one-half of the outer fiber strain where the stress is a maximum. Thus, by requiring the average bending stress to satisfy the allowable criterion for the direct state of stress, the average absolute strain may be 20% of the uniform strain. Consequently, the outer fiber strain may be 40% of the uniform strain. The maximum allowable outer fiber bending stress is then taken to be equal to the stress corresponding to 40% of the uniform strain or the yield strength, whichever is higher. For unirradiated type 304 stainless steel operating temperatures, the stress-strain curve gives the maximum stress intensity as 50,000 psi. For irradiated type 304 stainless steel, the stress limit is higher; therefore, it is conservative to use the unirradiated value.

For combinations of membrane and bending stresses, the maximum allowable stress is taken to be equal to the maximum stress corresponding to the strain distribution having the maximum outer fiber strain not in excess of 40% uniform strain and average strain not in excess of 20% uniform strain. Analogous to the uniaxial case, the maximum allowable membrane and total stress intensities for multiaxial stress distributions are 39,500 psi and 50,000 psi.

14.5.3.5 Effects of LOCA and Safety Injection on the Reactor Vessel

The effects of injecting safety injection water into the reactor coolant system following a postulated LOCA have been analyzed. WCAP 7304L gives a description of the program associated with this analysis. Below is a summary of the conditions that were considered.

For the reactor vessel, three modes of failure are considered: the ductile mode, the brittle mode, and the fatigue mode.

14.5.3.5.1 Ductile Mode

The failure criterion used for this evaluation is that there shall be no gross yielding across the vessel wall, using the material yield stress specified in Section III of the ASME Code. The combined pressure and thermal stresses during safety injection through the vessel thickness as a function of time have been calculated and compared to the material yield stress at various times during the safety injection transient.

The results of the analyses showed that local yielding may occur in approximately the inner 12% of the base metal and in the cladding.

14.5.3.5.2 Brittle Mode

The possibility of a brittle fracture of the irradiated core region has been considered from both a transition temperature approach and a fracture mechanics approach.

The failure criterion used for the transition temperature evaluation is that a local flaw cannot propagate beyond any given point where the applied stress remains below the critical propagation stress at the applicable temperature at that point.

The results of the transition temperature analysis showed that the stress-temperature condition in the outer 65% of the base metal wall thickness remains in the crack arrest region at all times during the safety injection transient. Therefore, if a defect were present in the most detrimental location and orientation (i.e., a crack on the inside surface and circumferentially directed), it could not propagate any farther than approximately 35% of the wall thickness, even considering the worst-case assumptions used in this analysis.

Both a local crack effect and a continuous crack effect have been considered, with the latter requiring the use of a rigorous finite element axisymmetric code. The results of the fracture mechanics analysis, considering the effects of water temperature, heat transfer coefficients, and fracture toughness of the material as a function of time, temperature, and irradiation show that the integrity of the reactor vessel is maintained throughout the life of the unit.

14.5.3.5.3 Fatigue Mode

The failure criterion used for the failure analysis is the one presented in Section III of the ASME Code. In this method, the piece is assumed to fail once the combined usage factor at the most critical location for all transients applied to the vessel exceeds the code allowance usage factor of one.

The results of this analysis show that the combined usage factor never exceeds 0.2, even after assuming that the safety injection transient occurs at the end of unit life.

In order to cause a fatigue failure during the safety injection transient at the end of unit life, it has been estimated that a wall temperature of approximately 1100°F is needed at the most critical area of the vessel (instrumentation tube welds in the bottom head).

The design basis of the emergency core cooling system ensures that the maximum cladding temperature does not exceed the clad melting temperature. This is achieved by prompt recovery of the core through flooding, with the passive accumulator and the active injection systems. Under these conditions, a vessel temperature of 1100°F is not considered a credible possibility, and the evaluation of the vessel under such elevated temperatures is a hypothetical case.

For the ductile failure mode, such hypothetical rise in the wall temperature would increase the depth of local yielding in the vessel wall.

The results of these analyses show that the integrity of the reactor vessel is never violated.

The safety injection nozzles have been designed to withstand 10 postulated safety injection transients without failure. This design and associated analytical evaluation were made in accordance with the requirements of Section III of the ASME Code.

The maximum calculated pressure plus thermal stress in the safety injection nozzle during the safety injection transient was calculated to be approximately 50,900 psi. This value compares favorably with the code-allowable stress of 80,000 psi.

These 10 safety injection transients are considered along with all the other design transients for the vessel in the fatigue analysis of the nozzles. This analysis shows the estimated usage factor for the safety injection nozzles to be 0.47, which is well below the code-allowable value of 1.0.

The safety injection nozzles are not in the highly irradiated region of the vessel, and thus they are considered ductile during the safety injection transient.

The effect of the safety injection water on the fuel assembly grid springs has been evaluated and, due to the fact that the springs have a large surface-area-to-volume ratio, and are in the form of thin strips, they are expected to follow the coolant temperature transient with very little lag; hence, no thermal shock is expected, and the core cooling is not compromised.

Evaluations of the core barrel and thermal shield have also shown that core cooling is not jeopardized under the postulated accident conditions.

14.5.4 Containment Iodine Removal by Spray System

The spray system is designed to reduce post-accident containment pressure by condensing steam and to adsorb inorganic or particulate iodine present in the containment atmosphere by chemical spray. The spray system design bases and description are discussed in Section 6.3.1.

The analyses establishing the amount of radioiodine in the containment following a LOCA were approved and documented in Reference 44. The spray removal coefficients used in the analyses for elemental and organic iodine were assumed to be 10 hr^{-1} and 0 hr^{-1}, respectively, consistent with NUREG-0800 (Standard Review Plan) Section 6.5.2 (Reference 15). The spray removal coefficients used in the analyses for particulate iodine and other aerosols were as indicated in Table 14.5-8. The spray removal coefficients in Table 14.5-8 were developed in accordance with the methodology of NUREG/CR 5966 (Reference 14). A maximum decontamination factor of 200 was applied to the elemental iodine. A two-region model was used to calculate the effective spray removal coefficients. The spray is effective over 61% of the containment volume until containment spray is terminated, at which time the sprayed volume is reduced to 18.78%. There is assumed to be a mixing rate of 2 unsprayed volumes per hour.

14.5.5 Environmental Consequences of Loss-of-Coolant Accident (LOCA)

The assumed design basis accident LOCA is defined as the double-ended guillotine failure of a cold leg reactor coolant pipe, the total loss of coolant through such a double-ended failure, a total loss of offsite station power, where that is conservative, the availability of only minimum safeguards, and release of the core fission product inventory indicated in Table 14.5-10 to the reactor containment atmosphere. The core iodines released during the LOCA take the following chemical and physical forms:

1. 4.85% elemental
2. 0.15% organic
3. 95.0% particulate

This section describes the method and results of the radiological analyses for the design basis accident. The analyses include TEDE doses from three sources: dose from the containment leakage plume and the dose due to 30 days of ECCS and RWST leakage following the accident. Doses were calculated at the exclusion area boundary, at the low population zone boundary, and in the control room. The LOCA dose analyses discussed below assume operation at the uprated power.

The methodology used to evaluate the control room and offsite doses resulting from a LOCA was consistent with the NRC Standard Review Plan (References 15, 17, 18, & 34), and the Regulatory Guide 1.183 (Reference 35). Core radionuclide inventory was based on a power level of 2605 MWt which is slightly conservative compared to the uprated power level for Surry of 2587 MWt plus 0.38% for instrument uncertainty.

Regulatory Guide 1.183 (Reference 35), provides detailed guidelines for calculating doses from a LOCA in a PWR. Doses from all postulated release paths to the environment are calculated as described in the SRP, and compared with 10 CFR 50.67 exposure criteria. Radiological consequences of both containment leakage and post-LOCA leakage from Engineered Safety Feature (ESF) system components outside containment, (including backleakage into the RWST) were considered.

To account for manual realignment of the safeguards area ventilation system to filtered exhaust, a 30-minute delay in filtration, which corresponds to the earliest time for recirculation mode transfer, is included in the analysis of doses resulting from a LOCA. Surry Units 1 and 2 share a single fuel building. Prior analyses of the fuel handling accident required that the auxiliary ventilation system be aligned in the refueling mode during fuel handling. This alignment was necessary unless sufficient decay had occurred since reactor shutdown to eliminate the need for filtration of radioiodine releases from postulated fuel handling accidents. With this alignment, a manual action was required to enable filtration of the exhaust from the safeguards area after a safety injection (SI) signal. Currently, air filtration is not required to mitigate a fuel handling accident, and procedural controls have been established to eliminate operating with automatic alignment defeated, but this action is still conservatively modeled. Additionally, while modeled as a 30-minute delay, Reference 54 indicates that realignment of the safeguards area ventilation system is not actually required until just prior to recirculation mode transfer, when contaminated sump water is recirculated outside containment. The Surry core radionuclide inventory was determined from calculations using the ORIGEN-ARP computer code that conservatively modeled a representative Surry core-loading plan.

Surry has a subatmospheric containment system. During the first hour following the accident containment pressure is analyzed to remain less than 45 psig. A 0.1 volume percent per day containment leak rate was used for the first hour after the LOCA, which corresponds to a maximum containment pressure of 45 psig. The original design criterion required that within one hour, containment pressure be calculated to return to subatmospheric conditions. This original design criterion was modified in conjunction with the analyses for implementation of the alternative source term and Generic Letter 2004-02. The criteria were subsequently updated to support an increase in the containment depressurization profile for the alternative source term analyses. The modified criteria require that, following the LOCA, the containment pressure be less than 2.0 psig within 1 hour and less than 0.0 psig within 6 hours. Therefore, from 1 hour to 6 hours after a LOCA, a 0.04 volume percent per day leak rate was assumed, which corresponds to a maximum containment pressure of 2.0 psig. Beyond 6 hours, containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment.

When the containment pressure is subatmospheric, any leakage would be into the containment. Therefore, no containment leakage is assumed after the fourth hour. Surry does not have a vent purge system that has to be considered as a LOCA release pathway.

The following containment spray removal coefficients were used:

Elemental Iodine = 10 per hour

Organic Iodine = 0 per hour

Particulate Iodine and other Particulates = per Table 14.5-8

Sprayed Volume = 61% (reduced to 18.78% at 1.14 hrs)

Mixing Rate = 2 unsprayed volumes/hour

Spray Start Time = 100 seconds (recirculation spray is not credited until 1.14 hrs)

Based on a review of the Basis for Surry Technical Specification 4.20, Regulatory Guide 1.25, and Regulatory Guide 1.52, the following control room and auxiliary building ventilation system filters efficiencies were used for Surry:

Iodine Type	Filter Efficiency

Elemental	90%
Methyl	70%
Particulate	99%

The 90% elemental and 70% methyl iodine removal efficiencies are indicated in Regulatory Guides 1.25 and 1.52 (References 19 & 37) as being appropriate for 2-inch charcoal filters without humidity control. The 99% efficiency for particulate iodine is based on the use of HEPA filters.

The ESF leakage was assumed to be 2 times the total allowable ECCS leakage of 15,000 cc/hour (Section 14.5.5.3) and the total allowable back-leakage into the RWST of 9,000 cc/hour. The RWST release to the atmosphere is modeled at 1000 cfm through the safeguards building and out ventilation vent No. 2. Filtration by the auxiliary building ventilation system was credited for the portion of the ECCS leakage that occurs in the Safeguards Building, primarily the 3,000 cc/hour of Outside Recirculation Spray System leakage identified in Section 14.5.5.3, and the RWST backleakage. The release of radionuclides to the environment was determined both for containment leakage and Engineered Safety Feature components leakage.

For the ECCS leakage dose calculation, forty percent of the core iodine inventory is assumed to be released to the sump. The water in the ESF system at Surry, including RWST back-leakage, is taken from the containment sump at temperatures less than 212°F except for a short period at the beginning of the accident. During the period of time that the water temperature in the sump exceeds 212°F, the flashing fraction is less than 10%. Therefore, Surry meets the requirements for assuming 10% of the iodine in the ESF system leakage becomes airborne (Reference 35). Of the 10% of the iodine that becomes airborne, 97% is modeled as elemental and 3% organic (Reference 35). All of the other radionuclides as indicated in Table 14.5-10 as being in the containment sump remain in the liquid phase (Reference 35) of ESF leakage. Therefore only the airborne iodine portion of radionuclides released through ESF leakage has any consequence for EAB. LPZ, and control room doses.

14.5.5.1 Methodology to Determine Atmospheric Dispersion Factors, Control Room Occupancy, and Breathing Rates

The parameter χ/Q defines the ratio of radionuclide concentration (χ in curies/m^3) to release rate (Q in curies/second). It depends on the site meteorology (average wind speed and atmospheric stability) and distance between source and receptor. The EAB and LPZ atmospheric dispersion factors (χ/Q) are given in Table 14.5-7 and were determined based on the PAVAN (NUREG/CR-2858) methodology (Reference 33) using meteorological data for 2009 to 2013. The “wake-credit not allowed” scenario of the PAVAN results was used, since the closest point of both the EAB and LPZ from the onsite release points is greater than 10 ‘building heights’ of the containment dome (the tallest wake-producing structure).

The control room χ/Q values were determined with the ARCON96 (Reference 32) methodology and meteorological data form the 1982 through 1986 time period. These values are listed in Table 14.5-7. Wake effects were considered in calculating the atmospheric dispersion factors for all the onsite receptor points. For all ARCON96 runs, the default cross sectional area of one of the containment buildings above grade was used to model a wake effect. This is reasonable since all the receptor points modeled would be expected to be in the wake of one of the containment buildings. Additionally, further conservatism was introduced by only considering one containment dome for wake effect impacts. All releases were modeled as ground-level releases even when the source point was elevated (e.g., ventilation vent No. 2).

The control room occupancy factors in Table 14.5-9 were also incorporated into the dose calculations to reflect that personnel would not be exposed to the released activity 100% of the time over the entire 30 day period. These occupancy factors are based on the guidance from Reference 35. The breathing rate used for the control room and EAB dose calculations was 3.5×10^{-4} m^3/sec. The breathing rate for the LPZ dose calculations was 3.5×10^{-4} m^3/sec for the first 8 hours, 1.8×10^{-4} m^3/sec from 8-24 hours, and 2.3×10^{-4} m^3/sec from 24 hours until the end of the accident.

14.5.5.2 RADTRAD-NAI Model for Surry LOCA Analysis

RADTRAD-NAI (Reference 31) was used to model the release of radionuclides for a LOCA at Surry. This computer code system first calculates radionuclide concentrations and releases to the environment. The RADTRAD-NAI computer code system modeled a LOCA at Surry with six volumes: 1) the environment, 2) the containment sump, 3) the portion of the containment covered by the Containment Chemical Spray System, 4) the portion of the containment not covered by the Chemical Spray System, 5) the RWST, and 6) the control room. The volumes used in the computer model were:

	0 - 1.14 hours	> 1.14 hours
Unsprayed containment volume	= 709,410 ft^3	1,477,392 ft^3
Sprayed containment volume	= 1,109,590 ft^3	341,608 ft^3
Sump volume	= 55,986 ft^3	
RWST Volume	= 50,502 ft^3	
Control room volume	= 2.23×10^5 ft^3	

The transport of radionuclides to the environment is modeled by specifying flow rates between the various volumes modeled. The mixing between the sprayed and unsprayed containment volumes was modeled based on 2 unsprayed volumes per hour. The containment leakage to the environment was modeled as 0.1 volume percent per day for the first hour. From 1 hour until 6 hours after the LOCA, a 0.04 volume percent per day leak rate was used. Beyond 6 hours, containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment. The appropriate containment leakage rates, based upon time in the accident, were applied proportionately to both the sprayed and unsprayed containment volumes during the first six hours of the LOCA.

ESF leakage to the environment is modeled at twice the potential leakage rates specified in footnote to Tables 6.2-6 and 6.3-2 and twice the RWST allowable back-leakage of 9,000 cc/hour:

Twice the Allowable Leak Rate

Time Period	ECCS filtered leakage (cc/hour)	ECCS unfiltered leakage (cc/hour)	RWST filtered back-leakage (cc/hour)	Comments
0–0.25 hours	0	0	0	
0.25–0.5 hours	0	6000	0	earliest start of the RS System
0.5–720 hours	6000	24000	18,000	earliest RMT

RWST back-leakage is the modeled ESF system leakage through ECCS check valves into the RWST after switching to the recirculation cooling mode.

RADTRAD-NAI utilizes the χ/Q values discussed in Section 14.5.5.1 to determine the radionuclide concentrations outside the control room and at the EAB and LPZ dose points. Radionuclide transport into the control room is then modeled by specifying flow rates from the environment outside the control room.

The control room ventilation system was modeled consistent with Reference 32 and Surry control room ventilation system design and operation. An unfiltered inleakage of 250 cfm was modeled from time 0 to 30 days. The control room was assumed to be isolated at the start of the event based on a SI signal. After the first hour, a filtered intake of 900 cfm was modeled. Control room ventilation filter efficiencies are indicated in Section 14.5.5.

The RADTRAD-NAI code system calculates radionuclide releases to the environment and radionuclide concentrations versus time in each volume. Dose conversion factors, occupancy factors, and breathing rates are then used along with the radionuclide concentrations to calculate doses. The breathing rates and occupancy factors used for the dose calculations were discussed in Section 14.5.5.1. The RADTRAD-NAI code system uses dose conversion factors based on Federal Guidance Report Nos. 11 and 12 (References 38 & 39) to determine the TEDE doses.

14.5.5.3 Results of Dose Calculations for LOCA

The calculated LOCA doses are given in Table 14.5-11. It should be noted that the control room TEDE dose does not include the dose due to direct shine from containment due to the control room wall thickness being at least 18 inches thick (Reference 17). The calculated doses are less than the 10 CFR 50.67 limits for the EAB and LPZ, and the control room.

Filtration by the auxiliary building ventilation system was credited for the portion of the ECCS leakage that occurs in the Safeguards Building, primarily the Outside Recirculation Spray System leakage and RWST backleakage. Filtration was not credited for the portion of the ECCS leakage that occurs in the Auxiliary Building, primarily the SI and Charging System leakage. However, only certain areas (the charging pump cubicles and safeguards) are provided with dedicated exhaust paths to the filters. This has the potential to lead to releases to the environment that may bypass the auxiliary building filters. However, since no filtration credit is taken (in areas without dedicated exhaust paths to filters) and all atmospheric dispersion factors were modeled as ground releases (Section 14.5.5.1) this analysis remains conservative. The total allowable RWST back-leakage is 9,000 cc/hour. The maximum allowable unfiltered leakage is limited to the SI and Charging Systems leakage of 12,000 cc/hour. The total allowable ECCS leakage of 15,000 cc/hour includes SI and Charging Systems leakage of 12,000 cc/hour and Outside Recirculation Spray System leakage of 3,000 cc/hour.

14.5.6 Summary

For breaks up to and including the double-ended guillotine break of a cold leg reactor coolant pipe, the emergency core cooling system with minimum safeguards will limit the clad temperature to below the melting temperature of the cladding and ensure that the core will remain in place and substantially intact, with its essential heat transfer geometry preserved. The emergency core cooling system design meets the core cooling criteria for all cases. This is confirmed by the results of the limiting cases for the small break and large break LOCA sensitivity analyses. The emergency core cooling system components meet the acceptance criteria throughout the range of break sizes with the high-head safety injection pumps mitigating the smaller breaks and the accumulators in conjunction with the pumped safety injection flow mitigating the larger breaks.

The design of the fuel assemblies and the core support structures is such that the pressure oscillations and flow transients resulting from any LOCA can be accommodated without changes that would affect the capability of the safety injection system to perform its required function.

The calculated TEDE doses at exclusion area boundary, low population zone boundary, and in the control room resulting from a design basis LOCA are within the regulatory limits stated in 10 CFR 50.67.

14.5 REFERENCES

1. Letter from W. L. Stewart (Va. Electric & Power Co.) to NRC, *Surry Power Station Units 1 and 2—Proposed Technical Specifications Change—Surry Improved Fuel Assembly,* Serial No. 87-188, May 26, 1987.
2. Letter from C. P. Patel (NRC) to W. L. Stewart (Va. Electric & Power Co.), *Surry Units 1 and 2—Issuance of Amendments Re: Control Rod Assemblies and Surry Improved Fuel,* Serial 88-209, January 6, 1988.
3. Regulatory Guide 1.157, *Best-Estimate Calculations of Emergency Core Cooling System Performance,* USNRC, May 1989.
4. WCAP-17642-P-A, Revision 1, *Westinghouse Performance Analysis and Design Model (PAD5)*, (Proprietary), November 2017.
5. WCAP-16996-P-A, Revision 1, *Realistic LOCA Evaluation Methodology Applied to the Full Spectrum of Break Sizes (FULL SPECTRUM LOCA Methodology)*, (Proprietary), November 2016.
6. WCAP-16009-P-A, Revision 1, *Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM),* (Proprietary), January 2005.
7. *Containment Pressure Analysis Code (COCO),* WCAP-8327 (Proprietary) and WCAP-8326 (Non-Proprietary), June 1974.
8. Letter from C. M. Stallings, Virginia Electric and Power Company, to E. G. Case, NRC, Serial No. 344, August 9, 1977.
9. S. Fabric, *Computer Program WHAM for Calculation of Pressure, Velocity, and Force Transients in Liquid Filled Piping Networks*, Kaiser Engineers Report No. 67-49-R, November 1967.
10. J. J. DiNunno et al., *Calculation of Distance Factors for Power and Test Reactor Sites,* USAEC, TXD 14844, March 1962.
11. Title 10 Code of Federal Regulations, Part 100 - Reactor Site Criteria.
12. Letter from C. M. Stallings, Vepco, to E. G. Case, NRC, Serial No. 587, dated December 28, 1977.
13. Letter from A. K. Banerjee, Stone & Webster, to W. C. Spencer, VEPCO, Letter No. NUS-10, 645, dated February 2, 1984.
14. NUREG/CR-5966, *A Simplified Model of Aerosol Removal by Containment Sprays,* D. A. Powers and S. B. Burson, Sandia National Laboratories, Albuquerque, New Mexico, 1993.

15. Standard Review Plan 6.5.2, *Containment Spray as a Fission Product Cleanup System*, Rev. 2, 1988.

16. Letter from J. Stolz, Chief Light Water Reactors, Branch 1 to W. L. Proffitt, dated July 9, 1976.

17. Standard Review Plan 6.4, *Control Room Habitability System*, Rev. 2, 1981.

18. Standard Review Plan 15.6.5, *Loss-of-Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary*, Rev. 2, 1981.

19. U. S. Nuclear Regulatory Commission, Regulatory Guide 1.25 (Safety Guide 25), *Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors,* March 23, 1972.

20. Letter from W. L. Stewart, Vepco, to U.S. NRC, Serial No. 89-381, dated June 1, 1989.

21. Letter from W. L. Stewart, Vepco, to U.S. NRC, Serial No. 89-381A, dated October 26, 1989.

22. Letter from C. M. Stallings, Vepco, to U.S. NRC, Serial No. 045A/020177, dated May 9, 1977.

23. Letter from B. C. Buckley, U.S. NRC, to Vepco, dated December 26, 1991.

24. Letter from S. A. Varga, U.S. NRC, to Vepco, dated August 1, 1988.

25. Letter from S. A. Varga, U.S. NRC, to Vepco, dated June 23, 1981.

26. EMF-2328(P)(A) Revision 0, *PWR Small Break LOCA Evaluation Model, S-RELAP5 Based.*

27. Framatome Licensing Report ANP-3676P, *Surry Fuel-Vendor Independent Small Break LOCA Analysis*, July 2018.

28. Code of Federal Regulations, Title 10, Part 50, Section 46, *Acceptance Criteria For Emergency Core Cooling Systems For Light-Water Nuclear Power Reactors*, August 2007.

29. Letter from W. L. Stewart, *Virginia Electric and Power Company, to NRC, Surry Power Station Units 1 and 2—Proposed Technical Specification Changes—FΔh Increase/Statistical DNBR Methodology,* Serial No. 91-374, dated July 8, 1991.

30. J. S. Ivey, M. Y. Young, *Westinghouse Methodology for Implementation of 10 CFR 50.46 Reporting*, WCAP-13451, October 1992.

31. James R. Harrell et al, *RADTRAD-NAI Release Version 1.2(QA) Documentation,* NAI-9912-04, Revision 6, April 2015, Zachry Nuclear Engineering, Inc., Richland, Washington.

32. NUREG/CR-6331, Rev. 1, *Atmospheric Relative Concentrations in Building Wakes, ARCON96,* USNRC, 1997.

33. NUREG/CR-2858, *PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations,* USNRC, 1982.

34. Standard Review Plan 15.0.1, *Radiological Consequence Analyses Using Alternative Source Terms,* Rev. 0, July 2000.

35. U. S. Nuclear Regulatory Commission Regulatory Guide 1.183, *Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,* July 2000.

36. NUREG-1465, *Accident Source Terms for Light-Water Nuclear Power Plants,* L. Soffer et al., February 1995.

37. U.S. Nuclear Regulatory Commission, Office of Standards Development, *Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plants,* Regulatory Guide 1.52, Revision 2, March 1978.

38. Federal Guidance Report No. 11, *Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion,* EPA 520/1-88-020, Environmental Protection Agency, Washington D.C., 1988.

39. Federal Guidance Report No. 12, *External Exposures to Radionuclides in Air, Water and Soil,* EPA 420-r-93-081, Environmental Protection Agency.

40. Deleted

41. Letter from J. P. O'Hanlon to NRC, Serial No. 94-509, *Virginia Electric and Power Company, Surry Power Station, Units 1 and 2, Proposed Technical Specification Changes to Accommodate Core Uprating*, August 30, 1994.

42. Letter from J. P. O'Hanlon to NRC, Serial No. 94-509A, *Virginia Electric and Power Company, Surry Power Station, Units 1 and 2, Core Uprating Licensing Report Revision Steam Generator Tube Rupture Reanalysis*, February 6, 1995.

43. Letter from B. C. Buckley (NRC) to J. P. O'Hanlon, *Surry Units 1 and 2—Issuance of Amendments RE: Uprated Core Power (Serial No. 94-509) (Tac Nos. M90364 and M90365)*, August 3, 1995.

44. Letter from John Klos (NRC) to D. Stoddard, *Surry Power Station, Units 1 And 2 - Issuance of Amendment Nos. 306 And 306 to Update of the Loss-Of-Coolant Accident Alternate Source Term Dose Analysis* (EPID L-2020-LLA-0258), November 19, 2021.

45. *Control Rod Insertion Following a Cold Leg LOCA Generic Analyses for 3-Loop and 4-Loop Plants,* WCAP-15704-P, October 2001.

46. K. Takeuchi, et al., *MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics*, WCAP-8708-P-A, Westinghouse Proprietary Class 2/WCAP-8709-A, NES Class 3 (Non-Proprietary), September 1977.

47. K. Takeuchi, et al., *MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model*, WCAP-9735, Revision 2, Westinghouse Proprietary Class 2/WCAP-9736, Revision 1, Non-Proprietary, February 1998.

48. WCAP-9401-P-A (Proprietary), WCAP-9402-NP-A (Non-proprietary), *Verification Testing and Analyses of the 17 x 17 Optimized Fuel Assembly,* August 1981.

49. Letter, T. H. Essig (USNRC) to Lou Liberatori (WOG), *Safety Evaluation of Topical Report WCAP-15029, 'Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions,' (TAC NO. MA1152),* November 10, 1998 (Enclosure 1 - Safety Evaluation Report).

50. Letter from John F. Stang (USNRC) to Robert P. Powers (Indiana Michigan Power Company), *Issuance of Amendments - Donald C. Cook Nuclear Plant, Units 1 and 2 (TAC Nos. MA6473 and MA6474),* December 23, 1999.

51. R. E. Schwirian, et al., *Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions,* WCAP-15029-P-A, Westinghouse Proprietary Class 2/WCAP-15030-NP-A, Revision 0, non-proprietary, January 1999.

52. WCAP-15245 (proprietary), WCAP-15246 (non-proprietary), *Control Rod Insertion Following a Cold Leg LBLOCA, D. C. Cook, Units 1 and 2,* May 28, 1999.

53. Letter, Robert L. Tedesco (USNRC) to T. M. Anderson, (Westinghouse), Acceptance for Referencing Topical Report WCAP-9401 (Proprietary)/WCAP 9402 (Non-Proprietary).

54. Technical Report NE-1460, Rev. 1, *Implementation of GOTHIC Containment Analyses and Revisions to the LOCA Alternate Source Term Analysis to Support Resolution of NRC GL 2004-02 for Surry Power Station,* July 2006.

55. AREVA Topical Report 43-BAW-10132P-A, *Analytical Methods Description, Reactor Coolant System Hydrodynamic Loading During a Loss-of-Coolant Accident*, 1979 (AREVA Proprietary).

56. AREVA Topical Report 43-1621-00, *Effects of Asymmetric LOCA Loads-Phase II*, July 1980 (BAW-1621) (AREVA Proprietary).

57. AREVA Topical Report 77-1126594-00, *Effects of Asymmetric LOCA Loadings-Phase II, Supplement 1, Responses to NRC Questions,* June 1981 (BAW-1621, Supp. 1) (AREVA Proprietary).

58. CRAFT2, Program Version 31.0 (AREVA Proprietary), *Fortran Program for Digital Simulation of a Multinode Reactor Plant During Loss of Coolant.*

59. BWHIST, Version 3.0 (AREVA Proprietary), *Force Evaluation and Pressure Integration*.

60. BWSPAN, Version 13.0 (AREVA Proprietary), *Linear Static and Dynamic Analysis*.

61. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 287 to Renewed Facility Operating License No. NPF-4, Amendment No. 270 to Renewed Facility Operating License No. NPF-7, Amendment No. 303 to Renewed Facility Operating License No. DPR-32, Amendment No. 303 to Renewed Facility Operating License No. DPR-37, Virginia Electric and Power Company, North Anna Power Station, Unit Nos. 1 and 2, Surry Power Station Unit Nos. 1 and 2, Docket Nos. 50-280, 50-281, 50-338, and 50-339, dated March 19, 2021.

62. *Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors*, 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3, January 1974.

63. Information Notice 98-29: *Predicted Increase in Fuel Rod Cladding Oxidation,* USNRC, August 1998.

64. Letter from J. A. Gresham (Westinghouse) to USNRC, U.S. Nuclear Regulatory Commission *10 CFR 50.46 Annual Notification and Reporting for 2017*, LTR-NRC-18-30, July 2018.

65. *Emergency Core Cooling Systems: Revisions to Acceptance Criteria*, Federal Register, V53, N180, pp. 35996-36005, September 1988.

66. Regulatory Guide 1.203, *Transient and Accident Analysis Methods*, USNRC, December 2005.

67. WCAP-8339, *Westinghouse Emergency Core Cooling System Evaluation Model – Summary*, June 1974.

68. Letter from K. L. Hosack (Westinghouse) to USNRC, U.S. Nuclear Regulatory Commission *10 CFR 50.46 Annual Notification and Reporting for 2018*, LTR-NRC-19-6, February 2019.

Table 14.5-1
PLANT OPERATING RANGE ALLOWED BY THE BEST-ESTIMATE LARGE BREAK LOCA ANALYSIS

Parameter	As-Analyzed Value or Range	Operating Range or Target Value
1.0 Plant Physical Description		
a. Dimensions	Nominal	N/A
b. Pressurizer location	On an intact loop	N/A
c. Hot assembly location	Anywhere in core[a]	N/A
d. Hot assembly type	15 x 15 Upgrade fuel design	15 x 15 Upgrade fuel design
e. Steam generator tube plugging level	≤ 7%	0% ≤ SGTP ≤ 7% (in any one SG)
f. Fuel assembly type	15 x 15 Upgrade fuel with Optimized ZIRLO cladding, non-IFBA or IFBA, with IFMs	15 x 15 Upgrade fuel with Optimized ZIRLO cladding, non-IFBA or IFBA, with IFMs
2.0 Plant Initial Operating Conditions		
2.1 Reactor Power		
a. Core power	≤ 100% of 2597 MWt	≤ 2597 MWt
b. Peak heat flux hot channel factor (F_Q)	≤ 2.5	≤ 2.5
c. Peak hot rod enthalpy rise hot channel factor ($F_{\Delta H}$)	≤ 1.7	≤ 1.7
d. Hot assembly radial peaking factor ($\overline{P}_{HA}$)	≤ 1.7/1.04	≤ 1.7/1.04
e. Hot assembly heat flux hot channel factor (F_{QHA})	≤ 2.5/1.04	≤ 2.5/1.04

a. 28 peripheral locations will not physically be lead power assemblies.
b. Minimum Measured flow is verified per Technical Specifications 3.12.F, DNB parameters.
c. Not used.
d. Plant control systems are designed to control these parameters to the stated values.
e. fL/D based on average L/D of 516.2.
f. The analyzed maximum transient operation fraction is the sum of the planned (0.2) and unplanned (0.1) transient operation fractions, plus 0.2, as defined by the approved methodology (Reference 5).
g. Containment response calculated for each transient using transient-specific mass and energy releases.

Table 14.5-1 (CONTINUED)
PLANT OPERATING RANGE ALLOWED BY THE BEST-ESTIMATE LARGE BREAK LOCA ANALYSIS

Parameter	As-Analyzed Value or Range	Operating Range or Target Value
2.0 Plant Initial Operating Conditions (continued)		
2.1 Reactor Power (continued)		
f. Maximum transient operation fraction [f]	≤ 0.5	≤ 0.5
g. Axial flux difference band at 100% power	± 11%	± 5%
h. MTC	≤ 0 at hot full power (HFP)	≤ 0 at hot full power (HFP)
i. Typical cycle length	18 months	18 months
j. Maximum steady state depletion, F_Q	2.0	≤ 2.0
2.2 Fluid Conditions		
a. T_{AVG}	570–5.6°F ≤ T_{AVG} ≤ 576 + 5.6°F	570 to 576°F[d]
b. Pressurizer pressure	2250–60 psia ≤ P_{RCS} ≤ 2250 + 60 psia	2250 psia[d]
c. Loop flow	TDF ≥ 88,500 gpm/loop	MMF ≥ TS Limit[b]
d. Upper head design	T_{HOT}	T_{HOT}
e. Pressurizer level (Nominal)	53.7% of span (694 ft^3)	53.7% of span @ 573°F T_{AVG}[d]
f. Accumulator temperature	89°F ≤ T_{ACC} ≤ 113°F	89.5°F ≤ T_{ACC} ≤ 113°F

a. 28 peripheral locations will not physically be lead power assemblies.
b. Minimum Measured flow is verified per Technical Specifications 3.12.F, DNB parameters.
c. Not used.
d. Plant control systems are designed to control these parameters to the stated values.
e. fL/D based on average L/D of 516.2.
f. The analyzed maximum transient operation fraction is the sum of the planned (0.2) and unplanned (0.1) transient operation fractions, plus 0.2, as defined by the approved methodology (Reference 5).
g. Containment response calculated for each transient using transient-specific mass and energy releases.

Table 14.5-1 (CONTINUED)
PLANT OPERATING RANGE ALLOWED BY THE BEST-ESTIMATE LARGE BREAK LOCA ANALYSIS

Parameter		As-Analyzed Value or Range	Operating Range or Target Value
2.0	Plant Initial Operating Conditions (continued)		
	2.2 Fluid Conditions (continued)		
	g. Accumulator pressure	580 psia $\leq P_{ACC} \leq$ 700 psia	600 psia $\leq P_{ACC} \leq$ 680 psia
	h. Accumulator liquid volume	965 $ft^3 \leq V_{ACC} \leq$ 1035 ft^3	975 $ft^3 \leq V_{ACC} \leq$ 1025 ft^3
	i. Accumulator fL/D	7.227[e]	Current line configuration
	j. Minimum accumulator boron	2250 ppm	≥ 2250 ppm
3.0	Accident Boundary Conditions		
	a. Minimum safety injection flow	Table 14.5-4	≥ Table 14.5-4
	b. Safety injection temperature	37.5°F ≤ SI Temp ≤ 62.5°F	40°F ≤ SI Temp ≤ 60°F
	c. Safety injection delay	25 seconds (with offsite power) 40 seconds (with LOOP)	≤ 25 seconds (with offsite power) ≤ 40 seconds (with LOOP)
	d. Containment modeling	See Figure 14.5-8 and raw data in Tables 14.5-2 and 14.5-5[g]	See Figure 14.5-8 and raw data in Tables 14.5-2 and 14.5-5[g]
	e. Recirculation spray initiation delay	900 seconds	≥ 900 seconds
	f. Single failure	Loss of one ECCS train	Loss of one ECCS train

a. 28 peripheral locations will not physically be lead power assemblies.
b. Minimum Measured flow is verified per Technical Specifications 3.12.F, DNB parameters.
c. Not used.
d. Plant control systems are designed to control these parameters to the stated values.
e. fL/D based on average L/D of 516.2.
f. The analyzed maximum transient operation fraction is the sum of the planned (0.2) and unplanned (0.1) transient operation fractions, plus 0.2, as defined by the approved methodology (Reference 5).
g. Containment response calculated for each transient using transient-specific mass and energy releases.

Table 14.5-2
CONTAINMENT DATA USED FOR REGION II FSLOCA (LBLOCA) CALCULATION OF CONTAINMENT PRESSURE

Parameter	**Value**
Maximum containment net free volume	1,819,000 ft^3
Minimum initial containment temperature at full power operation	102 °F (1)
Refueling Water Storage Tank (RWST) temperature for containment spray	37.5 °F ≤ T_{RWST} ≤ 62.5 °F
Minimum RWST temperature for broken loop spilling SI	37.5 °F
Minimum containment outside air / ground temperature	9 °F
Minimum initial containment pressure at normal full power operation	9.85 psia
Minimum containment spray pump initiation delay from containment high pressure signal time	59 seconds (LOOP and OPA)
Maximum containment spray flow rate from all pumps	4625 gpm
Maximum number of containment fan coolers in operation during LOCA transient	0
Maximum number of containment venting lines (including purge lines, pressure relief lines or any others) which can be OPEN at onset of transient at full power operation	0
Containment walls / heat sink properties	Table 14.5-5

1. One containment heat sink, corresponding to the containment mat and subfloor, is initialized at a lower minimum temperature of 45°F.

Table 14.5-3
REGION II FSLOCA (LBLOCA) ANALYSIS RESULTS

Outcome	Region II Value (OPA)	Region II Value (LOOP)	Criterion
95/95 PCT *	1844°F + 31°F = 1875°F	1817°F + 31°F = 1848°F	≤ 2200 °F
95/95 Total MLO ** [Transient MLO]	6.23% [1.33%]	6.49% [3.57%]	≤ 17%
95/95 CWO	0.37%	0.43%	≤ 1%

* The PCT values presented in the table show the analysis-of-record result, which is the sum of the uncertainty analysis result plus the impact of the energy redistribution error correction. The figures presenting the analysis results correspond to the uncertainty analysis results. The MLO and CWO were confirmed to demonstrate compliance with the 10 CFR 50.46 acceptance criteria with the error correction.

** The MLO values presented in the table show the uncertainty analysis result. However, an evaluation of revised pre-transient oxidation (PTO) data was completed, resulting in a total MLO increase of 2.26% for both OPA and LOOP to 8.49% and 8.75%, respectively.

Table 14.5-4
MINIMUM SAFETY INJECTION FLOW (TOTAL IN INTACT LOOPS)
USED IN REGION II FSLOCA (LBLOCA) ANALYSIS

Pressure (psia)	**High Head Safety Injection (HHSI) Flow (gpm)**	**Low Head Safety Injection (LHSI) Flow (gpm)**
14.7	253.2	2015.8
54.7	249.5	2015.8
64.7	248.6	2015.8
69.7	248.2	1843.8
89.7	246.4	1479.2
114.7	244.1	970.6
139.7	241.6	391.2
149.7	240.6	259.7
154.7	240.1	108.4
154.8	240.1	0.0
214.7	234.1	
514.7	203.2	
1014.7	144.0	
1264.7	111.1	
1414.7	89.5	
1731,7	31.2	
2014.7	0.0	

Table 14.5-5
CONTAINMENT HEAT SINK DATA USED FOR REGION II FSLOCA (LBLOCA) CALCULATION OF CONTAINMENT PRESSURE

Wall	**Area (ft^2)**	**Thickness (ft)**	**Material**
1	8500	0.00025, 0.5	Paint, Concrete
2	62500	0.00025, 1.0	Paint, Concrete
3	47500	0.00025, 1.5	Paint, Concrete
4	8000	1.5	Concrete (1)
5	12000	2.0	Concrete
6	9500	2.25	Concrete
7	4000	3.0	Concrete
8	44000	0.00025, 0.03125, 4.5	Paint, Carbon Steel, Concrete
9	2500	0.03125, 4.5	Carbon Steele, Concrete (1)
10	26000	0.00025, 0.04167, 2.5	Paint, Carbon Steel, Concrete
11	12500	0.00025, 2.2	Paint, Concrete
12	12400	0.0005, 0.01967	Paint, Carbon Steel
13	3000	0.012	Carbon Steel (1)
14	73260	0.0005, 0.03608	Paint, Carbon Steel
15	13740	0.03608	Carbon Steel
16	14615	0.0005, 0.07458	Paint, Carbon Steel
17	3885	0.07458	Carbon Steele, Concrete (1)
18	4000	0.0005, 0.14167	Paint, Carbon Steel
19	12500	0.0005, 0.24167	Paint, Carbon Steel
20	105000	0.005	Carbon Steel
21	48000	0.0097	Stainless Steel
22	17500	0.03567	Stainless Steel
23	2500	0.12783	Stainless Steel

1. Uncoated structure in the break zone of influence.

Table 14.5-6
PEAK CLADDING TEMPERATURE INCLUDING ALL PENALTIES AND BENEFITS, REGION II FSLOCA (LBLOCA)

PCT for Analysis of Record (AOR)	1875°F
PCT Assessments Allocated to AOR	
Reactor Vessel Upflow Conversion	46 °F
LBLOCA PCT for Comparison to 10 CFR 50.46 Requirements	1921°F

Table 14.5-7
SURRY CONTAINMENT AND ECCS χ /Q VALUES

Time Period	Control Room χ/Q (sec/m^3) Containment Source	Control Room χ/Q (sec/m^3) ECCS & RWST (Vent No. 2)	EAB χ/Q Value (sec/m^3)	LPZ χ/Q Value (sec/m^3)
0-2 hours	4.67E.04	6.55E-04	1.02E-3	5.66E.05
2-8 hours	3.67E-04	4.93E-04	-	3.84E-05
8-24 hours	1.50E-04	2.03E-04	-	3.84E-05
24-96 hours	1.13E-04	1.44E-04	-	1.66E-05
96-720 hours	8.78E-05	1.08E-04	-	4.95E-06

Table 14.5-8
COMBINED CONTAINMENT AND RECIRCULATION SPRAY AEROSOL (PARTICULATE) REMOVAL COEFFICIENTS

Time (hr)	λ_{mf} (hr^{-1})
2.78E-02	3.59E+00
1.94E-01	3.69E+00
5.56E-01	4.16E+00
1.00E+00	4.40E+00
1.14E+00	3.04E+01
1.80E+00	1.94E+01
1.83E+00	1.35E+01
1.87E+00	7.21E+00
2.02E+00	3.91E+00
2.61E+00	3.43E+00
7.20E+00	0

Table 14.5-9
SURRY CONTROL ROOM OCCUPANCY FACTORS[a]

Time	Occupancy Factor
0 - 8 hr	1.0
8 - 24 hr	1.0
24 - 96 hr	0.6
96 - 720 hr	0.4

a. These values also used for LRA, SGTR, and MSLB accident dose analyses.

Table 14.5-10
CORE FISSION PRODUCT RELEASE FRACTIONS FOR THE LOCA
AS SPECIFIED BY REGULATORY GUIDE 1.183

	Core Release Fraction	
Group	Gap	Early In-Vessel
Noble Gases[b]	0.05	0.95
Halogens	0.05	0.35
Alkali Metals	0.05	0.25
Tellurium	0	0.05
Barium, Strontium	0	0.02
Noble Metals	0	0.0025
Cerium	0	0.0005
Lanthanides	0	0.0002
Duration (hr)[a]	0.5	1.3

a. Release duration and fractions apply only to the Containment release. The ECCS leakage portion of the analysis conservatively assumes that the entire core release fraction is in the containment sump from the start of the LOCA.
b. Noble Gases are not scrubbed from the containment atmosphere and therefore are not found in either the sump or ECCS fluid.

Table 14.5-11
LOCA CONTROL ROOM AND OFFSITE TEDE DOSE CONSEQUENCES COMPARED TO THE TEDE DOSE LIMITS OF 10 CFR 50.67

	Control Room (Rem TEDE)	Exclusion Area Boundary (Rem TEDE)	Low Population Zone (Rem TEDE)
Total Dose Consequences including contributions from containment, ECCS and RWST leakage	4.7	10.6	2.1
10 CFR 50.67 dose limits	5	25	25

a. 10 CFR Part 50.67 establishes TEDE dose limits for the EAB, the outer boundary of the LPZ, and for the control room for use with the alternate source term.

Table 14.5-12
SYSTEM PARAMETERS AND INITIAL CONDITIONS

Parameter	Analysis Value
Reactor Power, MWt	2597 [1]
Total Peaking Factor, F_Q	2.5 [1]
Radial Peaking Factor, $F\Delta h$	1.70 [1]
RCS Flow Rate, gpm	265,500
Pressurizer Pressure, psia	2250
RCS Average Temperature, °F	581.6
Accumulator Pressure, psia	580.0
Accumulator Fluid Temperature, °F	110.0
Accumulator Water Volume, ft^3	965.00
SG Tube Plugging Level per SG, %	7
SG Secondary Pressure, psia	800
MSSV Lift Pressure and Tolerance	Nominal + 3% tolerance
MFW Temperature, °F	438.1
AFW Flow Rate per fed SG, gpm	233.3
AFW Temperature, °F	120.0
Pressurizer Pressure – Low Reactor Trip Setpoint (RPS), psia	1899.7
Reactor Trip Delay Time on Low Pressurizer Pressure[2], sec	2.0
Reactor Scram Delay Time, sec	0.0
SIAS Activation Pressurizer Pressure Setpoint, psia	1715.0
HHSI and LHSI Pump Delay Time on SIAS, sec	40.0
HHSI and LHSI Fluid Temperature, °F	62.5
Low-Low SG Level Setpoint, % Narrow Range Span	0.1
AFW Delay, sec	60.0

[1] Includes associated measurement uncertainty

[2] Includes scram delay

Table 14.5-13
HHSI FLOW RATES

Pressure (psia)	Total Intact Flow (gpm)	Broken Flow (gpm)
0.0	253.2	146.6
14.7	253.2	146.6
64.7	250.3	144.9
114.7	247.3	143.2
214.7	241.5	139.8
514.7	233.9	129.7
1014.7	191.9	111.7
1264.7	173.7	101.1
1414.7	162.1	94.6
1731.7	131.0	76.2
2014.7	101.5	59.1
2114.7	89.2	52.5

Table 14.5-14
LHSI FLOW RATES

Pressure (psia)	**Total Intact Flow (gpm)**	**Broken Flow (gpm)**
0.0	2015.8	1007.9
14.7	2015.8	1007.9
52.7	2015.8	1007.9
64.7	1850.0	925.0
69.7	1746.7	873.3
89.7	1401.3	700.6
114.7	919.5	459.7
139.7	370.6	185.3
149.7	246.1	123.0
154.7	102.7	51.3
2114.7	0.0	0.0
	0.0	0.0

Table 14.5-15
2.6 INCH BREAK- SEQUENCE OF EVENTS

Event	**Time (sec.)**
Break Opening	0.0
Low PZR Pressure Trip	12.2
Reactor Scram, RCP and Turbine Trip	14.2
SIAS Issued	25.6
HHSI Flow: Loop 1/2/3, Broken	66/66/66
AFW: SG 1/2/3	84/84/84
Core Uncovery	333
Loop Seal Clearing: Loop 3, Broken	593
Break Uncovery	595
Accumulator Flow: Loop 1/2/3, Broken	1662/1662/1662
PCT Time	1785
Loop Seal Clearing: Loop 2	2426
Loop Seal Clearing: Loop 1	2427
Approximate Core Quench	2470
Hot Rod Rupture Time	-
LHSI Flow: Loop 1/2/3, Broken	-/-/-

Table 14.5-16
SBLOCA PEAK CLAD TEMPERATURE INCLUDING
ALL PENALTIES AND BENEFITS

Unit 1 and Unit 2	**PCT**
Analysis of Record	1673 ºF
Assessment Allocated to Analysis of Record	
A. ΔPCT	
Reactor Vessel Upflow Conversion	21 ºF
B. SBLOCA PCT for Comparison to 10 CFR 50.46 Requirements	1694 ºF

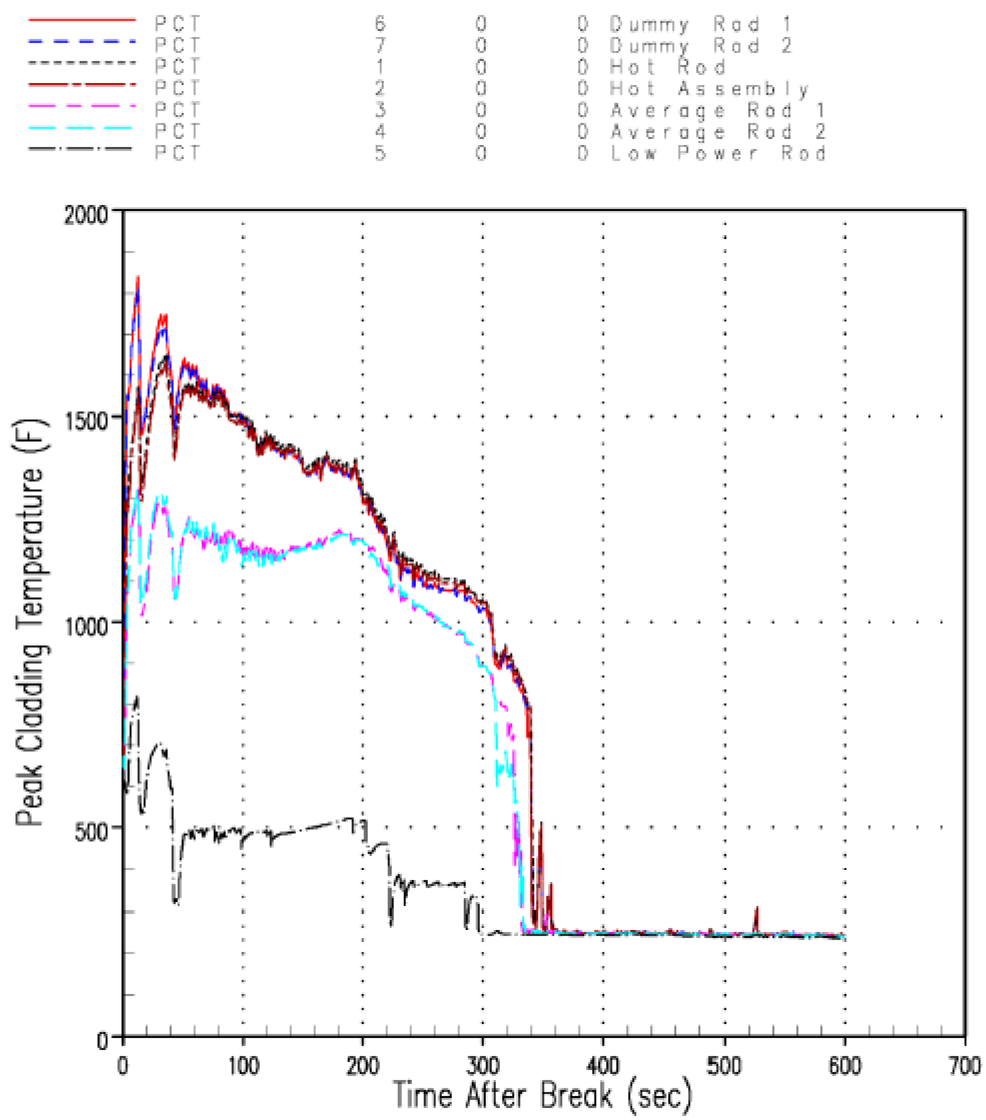
Table 14.5-17
SURRY UNITS 1 AND 2 SEQUENCE OF EVENTS FOR THE
REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

Event	Time After Break (sec)
Start of transient	0.0
Burst Occurs	~ 3.0
Safety Injection Signal	4.8
Accumulator Injection Begins	12.0
PCT Occurs	12.5
End of Blowdown	~20.0
Safety Injection Begins	29.8
Bottom of Core Recovery	~ 30.0
Accumulator Empty	~45.0
All Rods Quenched	~350
End of Analysis Time	600

Table 14.5-18
SURRY UNITS 1 AND 2 INCREASED BREAK OPENING TIMES USED FOR EVALUATION OF RPV SLIDING FOOT SUPPORTS

RCS Branch Line Break Case	**Break Opening Time (milliseconds)**
RHR Line Break	26.6
SI Line Break	23.4
PZR Surge Line Break	20.6

Figure 14.5-1
SURRY UNITS 1 AND 2 PEAK CLADDING TEMPERATURE FOR ALL RODS INCLUDING PASSIVE (DUMMY) RODS FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE



Note: This figure presents the uncertainty analysis results without the PCT penalty for the gamma energy redistribution error correction.

Figure 14.5-2
SURRY UNITS 1 AND 2 PEAK CLADDING TEMPERATURE ELEVATION
(RELATIVE TO BOTTOM OF ACTIVE FUEL) FOR
THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

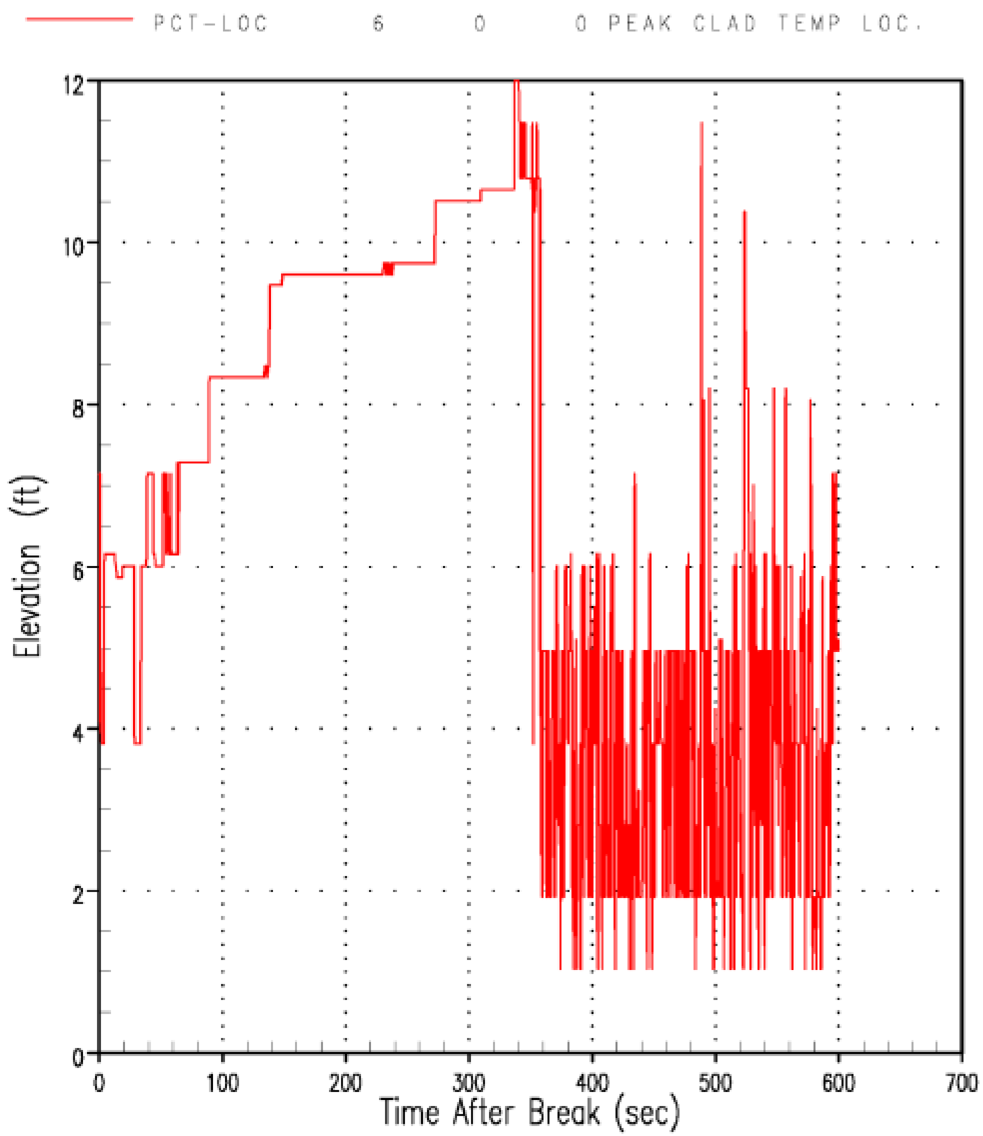
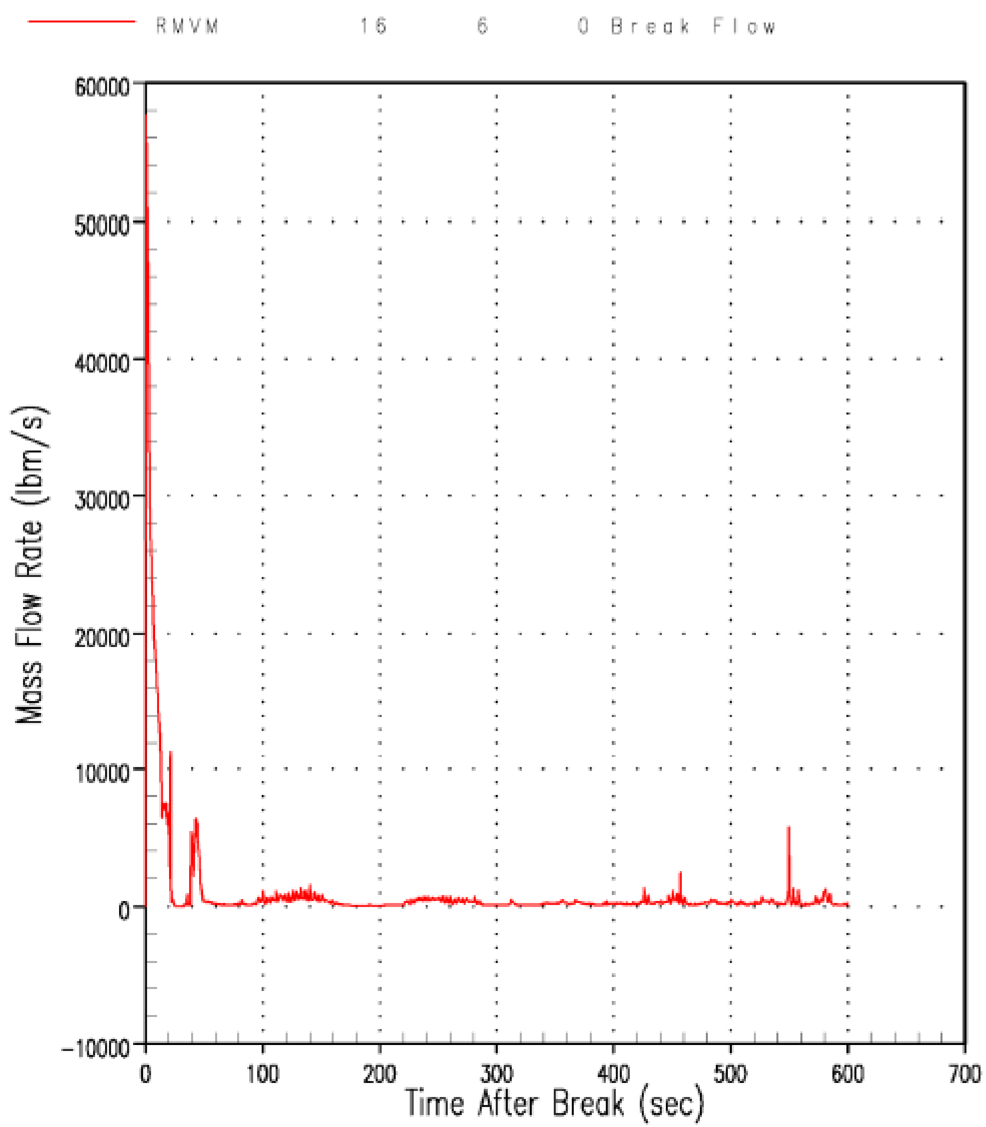


Figure 14.5-3
SURRY UNITS 1 AND 2 BREAK MASS FLOW RATE FOR
THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE



Note: There is only a single break mass flow rate since the Region II analysis PCT case modeled a split break.

Figure 14.5-4
SURRY UNITS 1 AND 2 LOWER PLENUM COLLAPSED LIQUID LEVEL (RELATIVE TO INSIDE BOTTOM OF VESSEL) FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

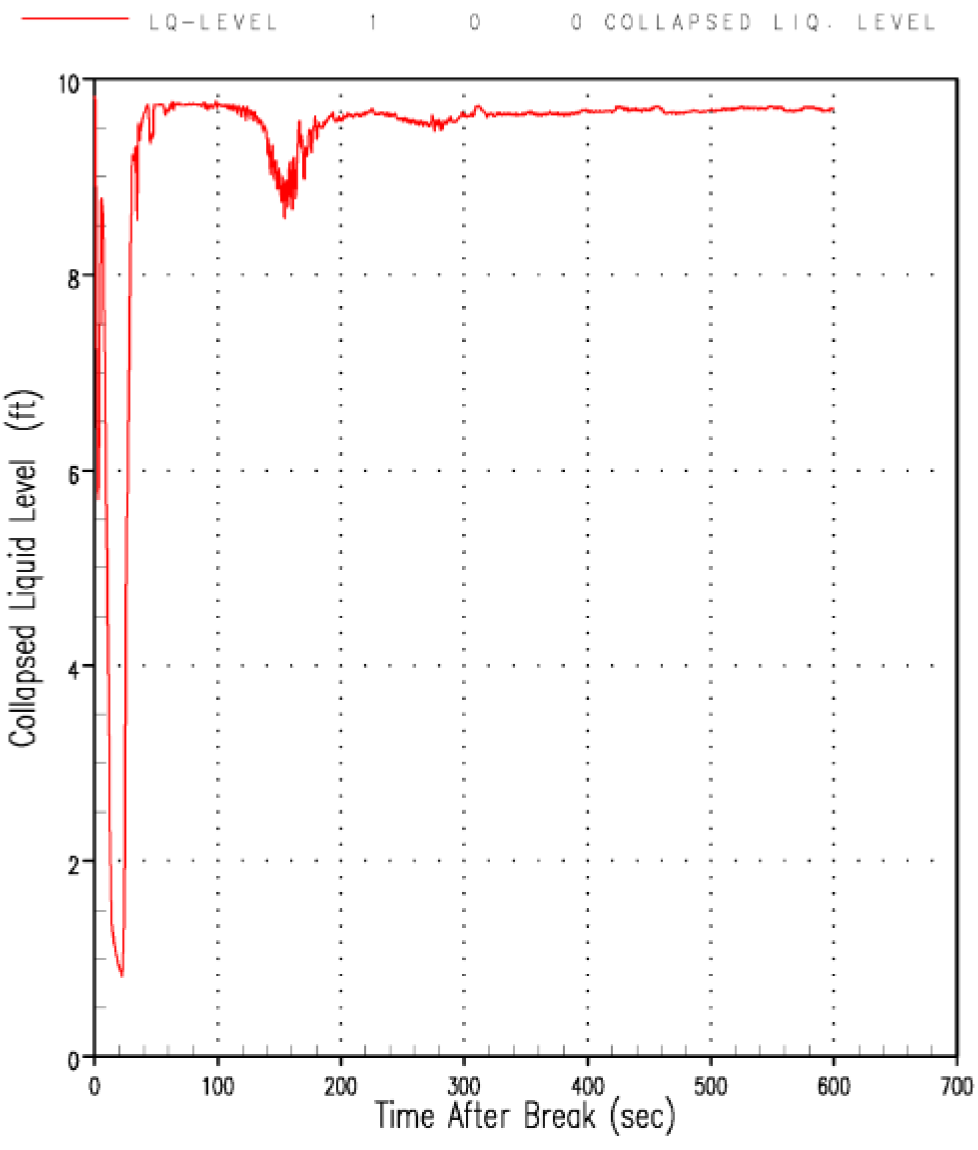


Figure 14.5-5
SURRY UNITS 1 AND 2 VAPOR MASS FLOW RATE AT THE
TOP AND BOTTOM CELL FACES OF THE CORE AVERAGE CHANNEL
NOT UNDER GUIDE TUBES FOR THE REGION II FSLOCA
(LBLOCA) ANALYSIS PCT CASE

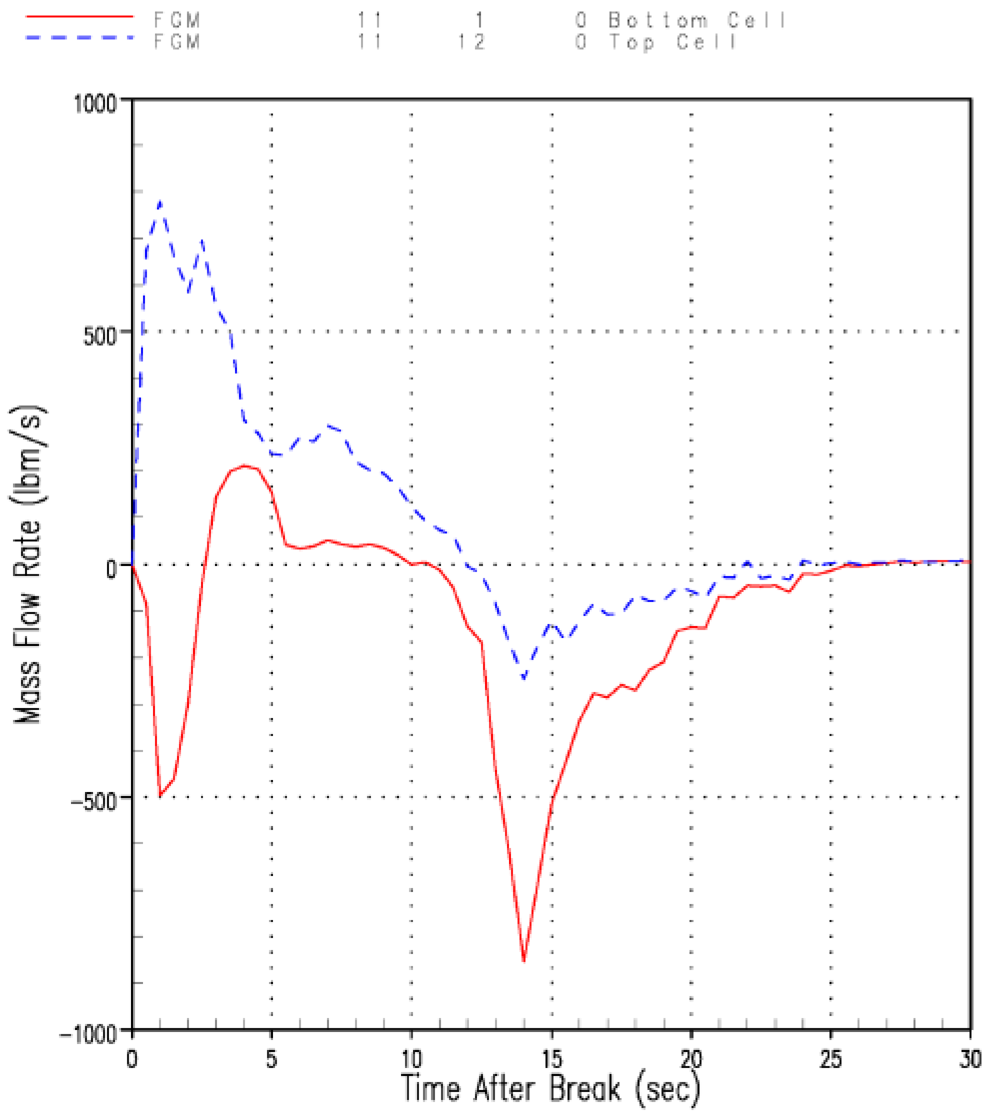


Figure 14.5-6
SURRY UNITS 1 AND 2 RCS PRESSURE
FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

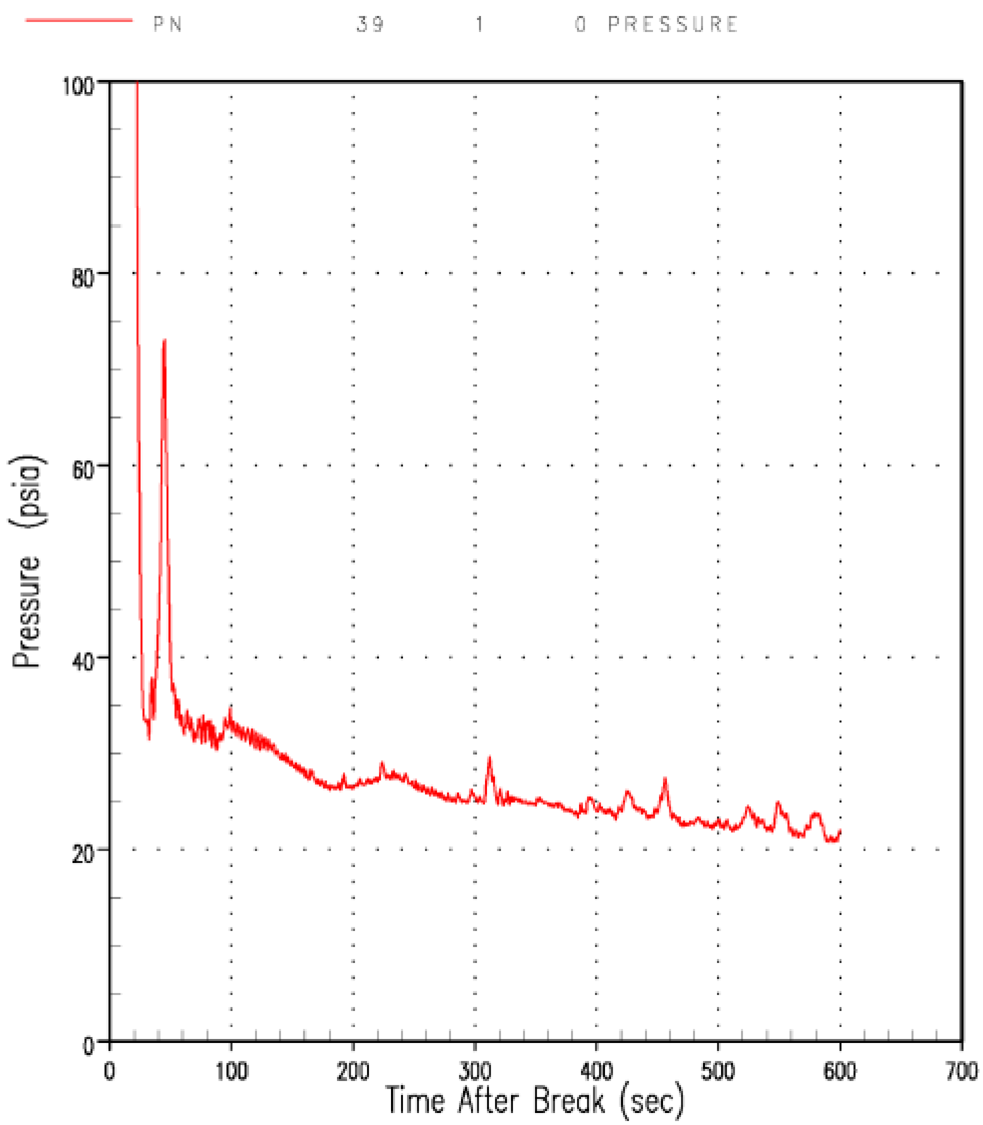


Figure 14.5-7
SURRY UNITS 1 AND 2 ACCUMULATOR INJECTION FLOW PER LOOP
FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

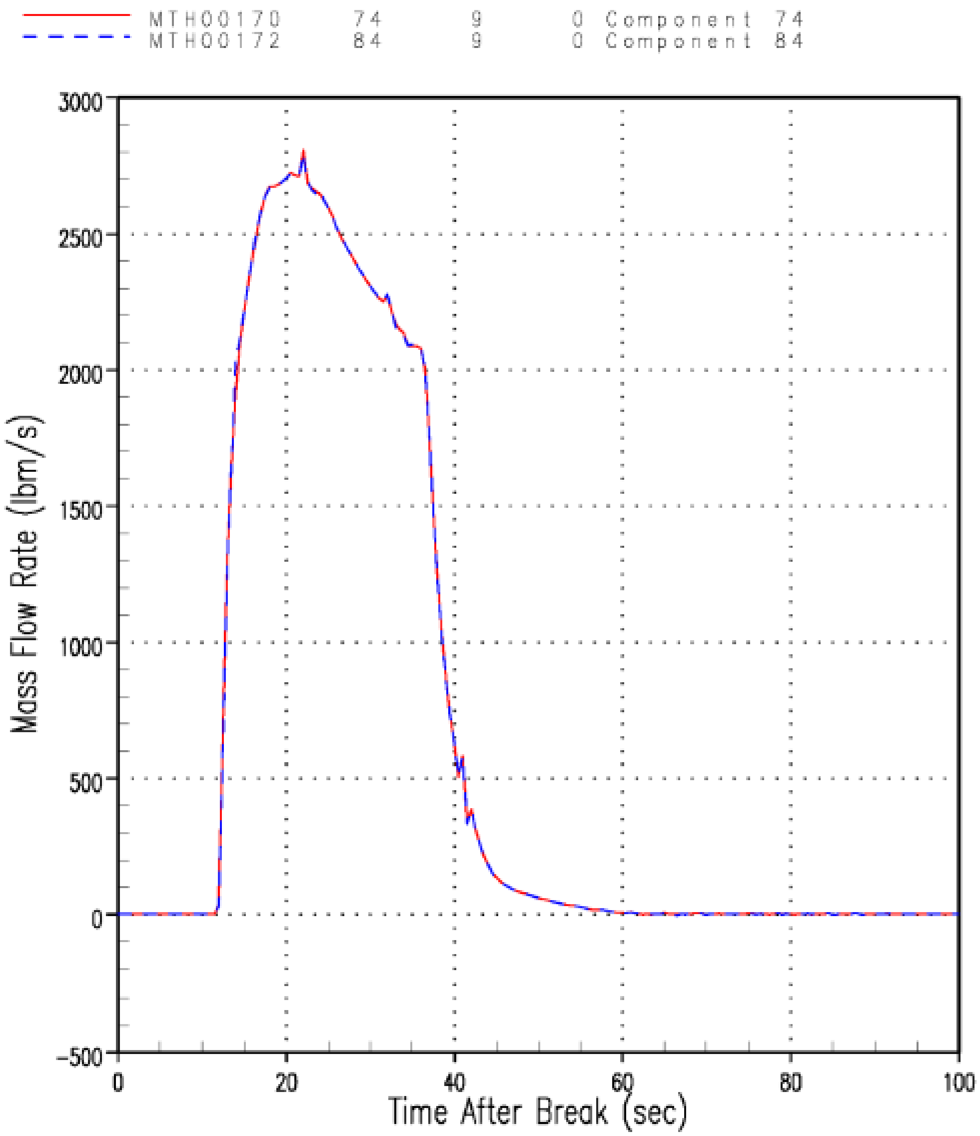


Figure 14.5-8
SURRY UNITS 1 AND 2 CONTAINMENT PRESSURE
FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

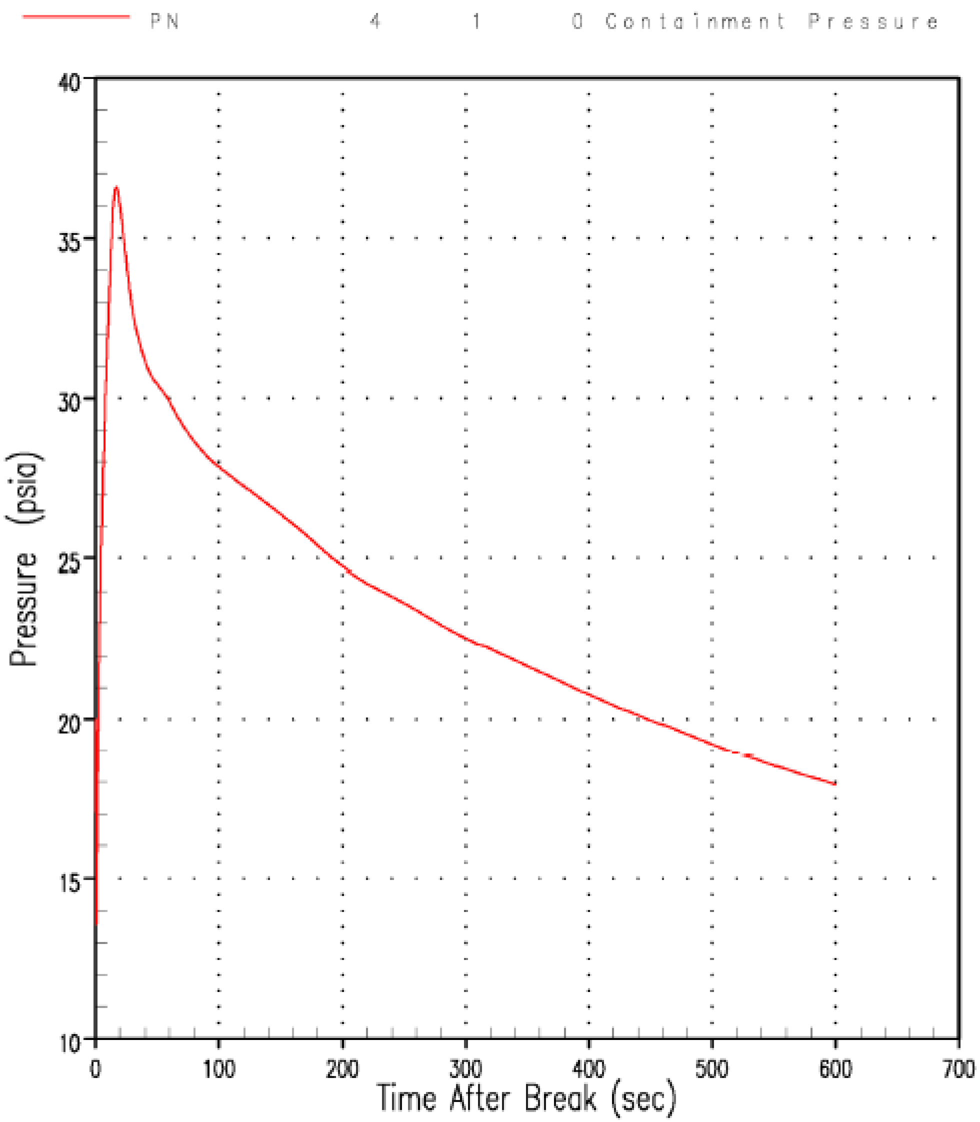


Figure 14.5-9
SURRY UNITS 1 AND 2 VESSEL FLUID MASS
FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

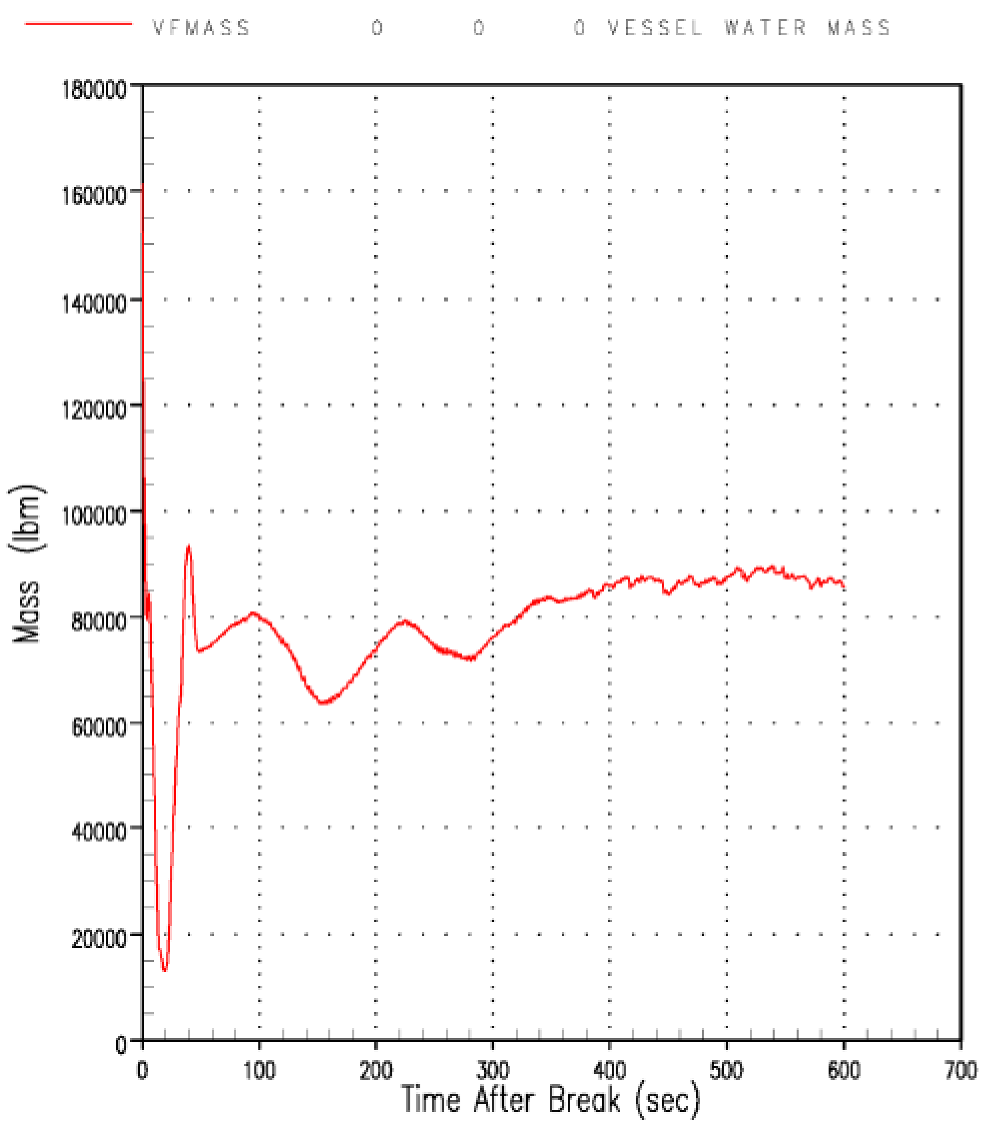


Figure 14.5-10
SURRY UNITS 1 AND 2 COLLAPSED LIQUID LEVEL FOR EACH CORE CHANNEL (RELATIVE TO BOTTOM OF ACTIVE FUEL) FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

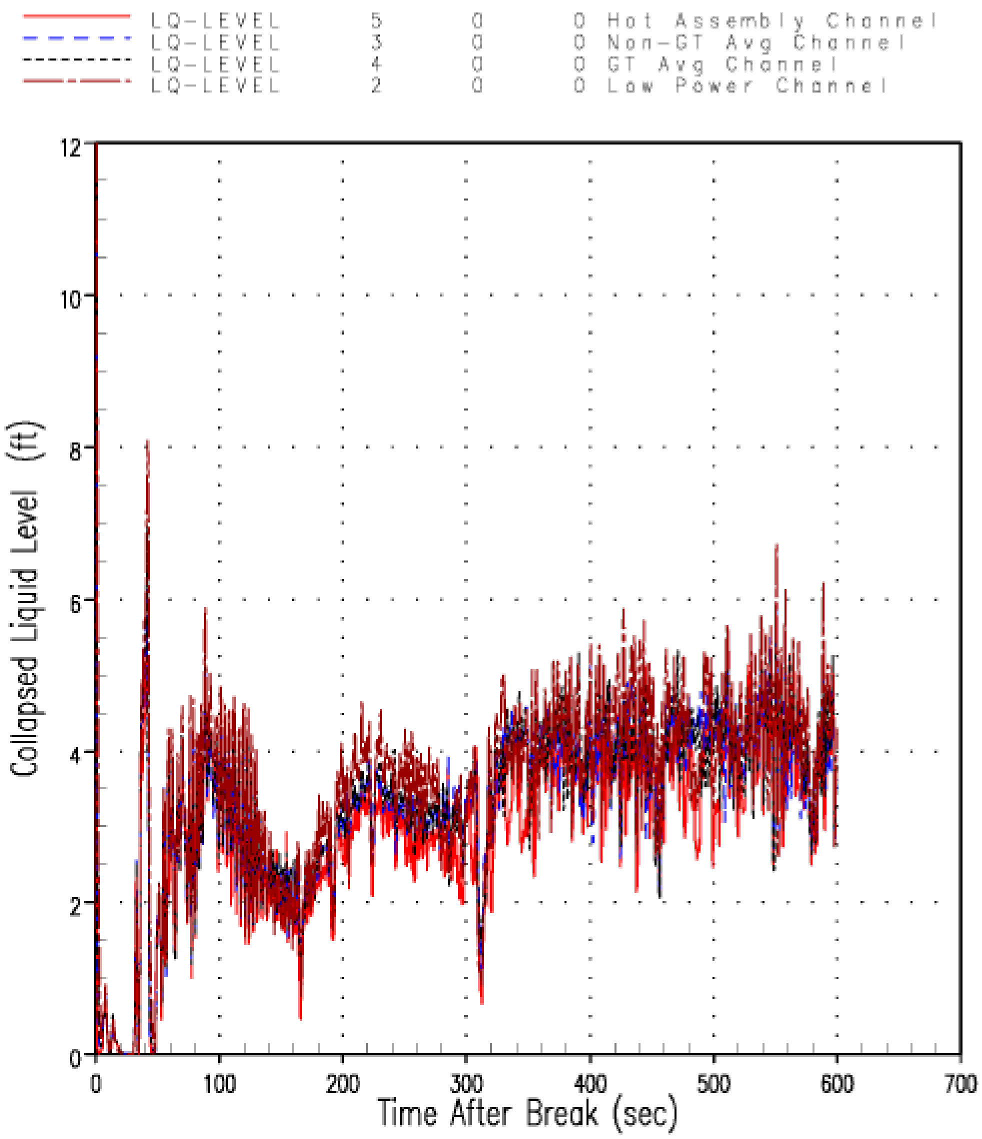


Figure 14.5-11
SURRY UNITS 1 AND 2 AVERAGE DOWNCOMER COLLAPSED LIQUID LEVEL (RELATIVE TO TOP OF THE UPPER TIE PLATE) FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

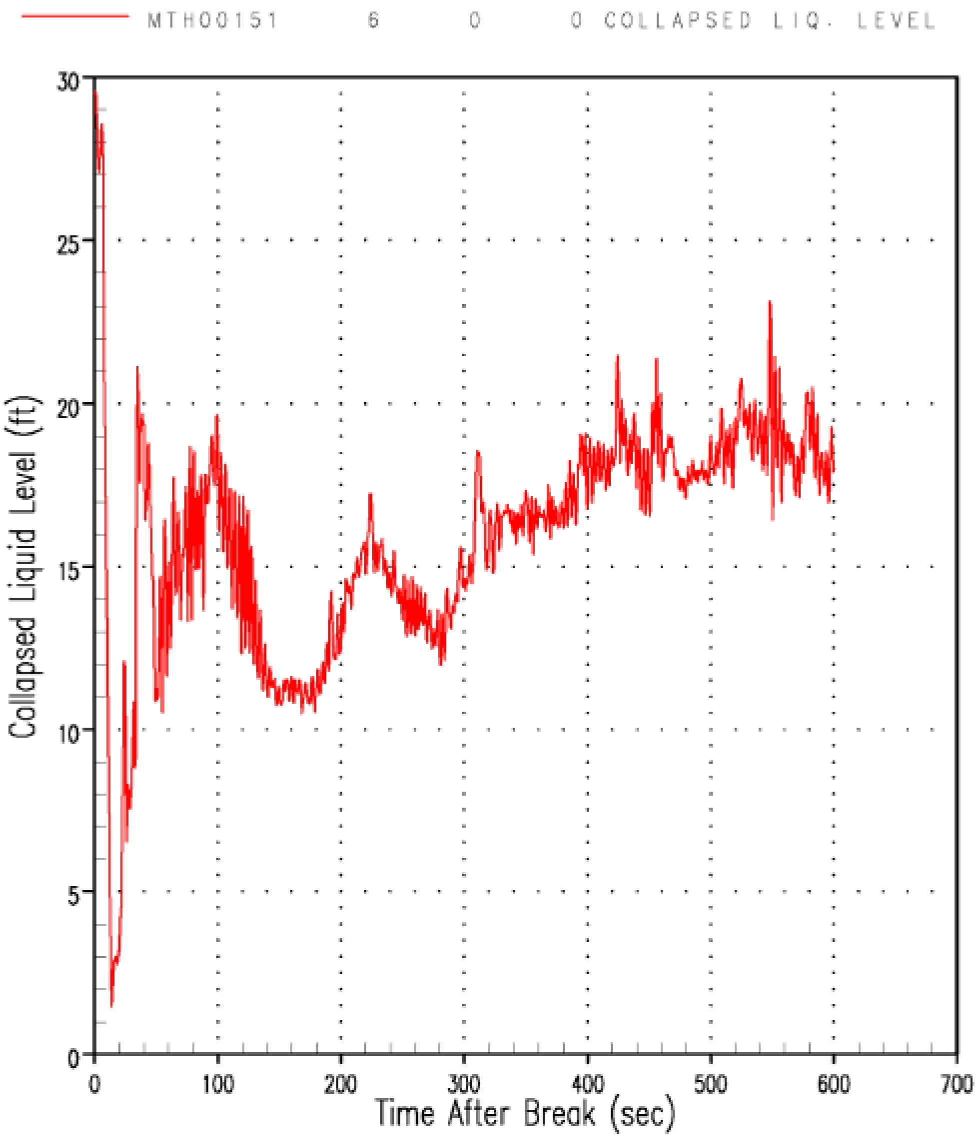


Figure 14.5-12
SURRY UNITS 1 AND 2 SAFETY INJECTION FLOW PER LOOP
(NOT INCLUDING ACCUMULATOR INJECTION FLOW)
FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

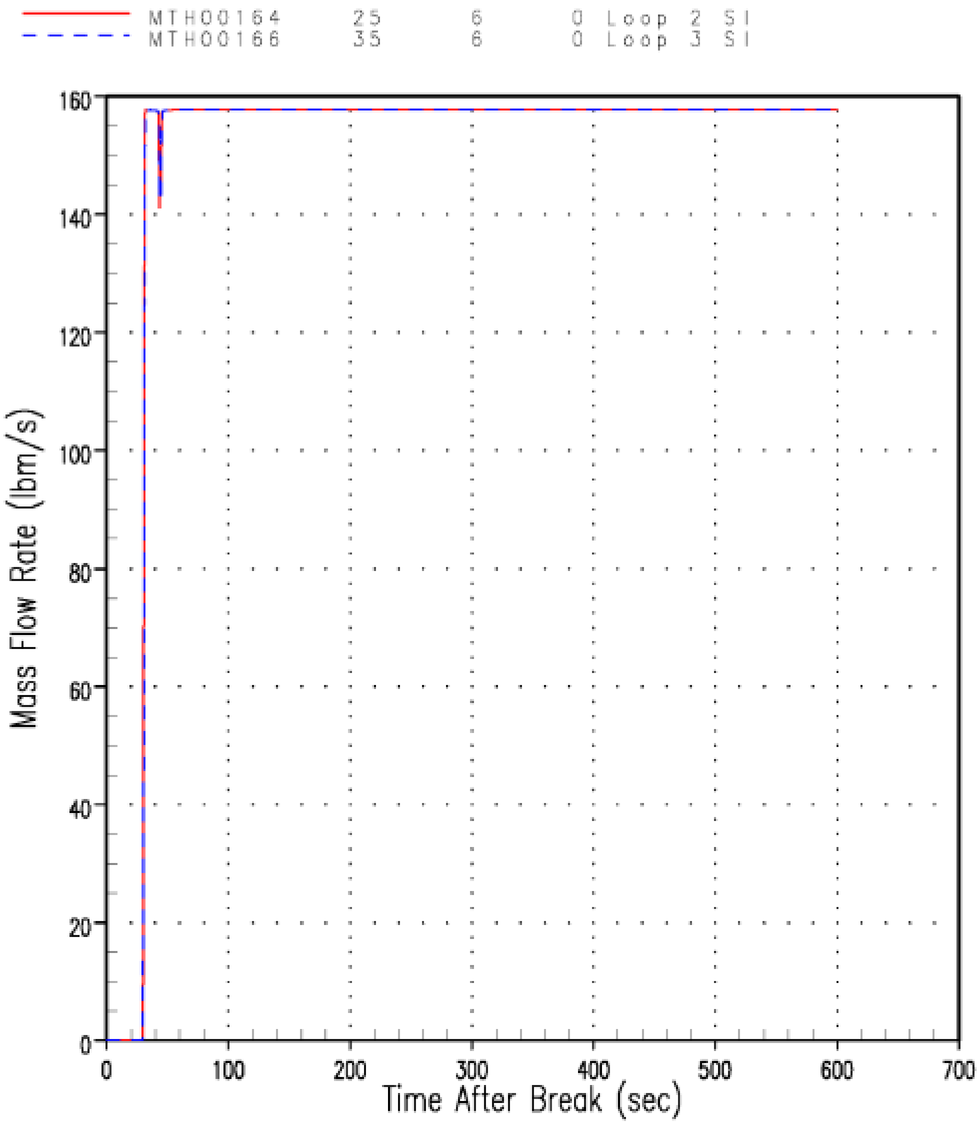


Figure 14.5-13
SURRY UNITS 1 AND 2 NORMALIZED ROD AXIAL POWER SHAPES
FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

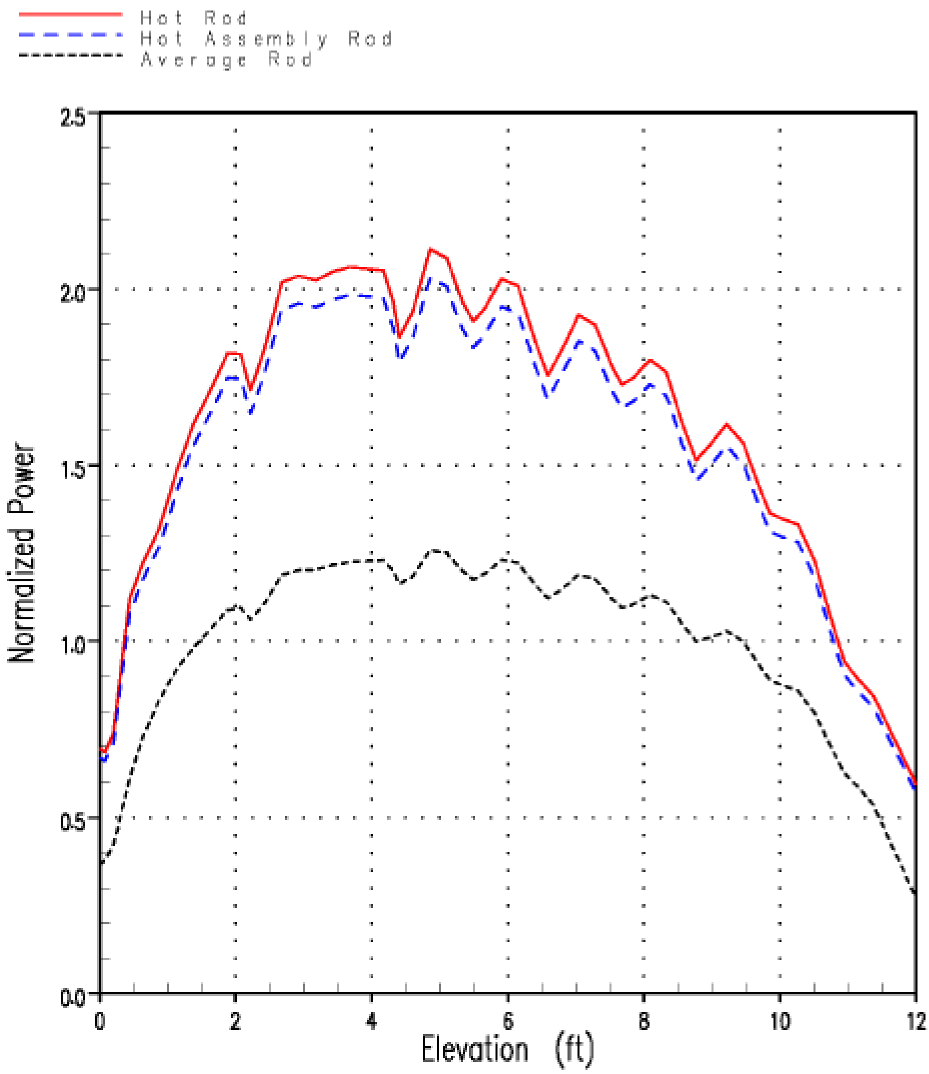


Figure 14.5-14
SURRY UNITS 1 AND 2 RELATIVE CORE POWER
FOR THE REGION II FSLOCA (LBLOCA) ANALYSIS PCT CASE

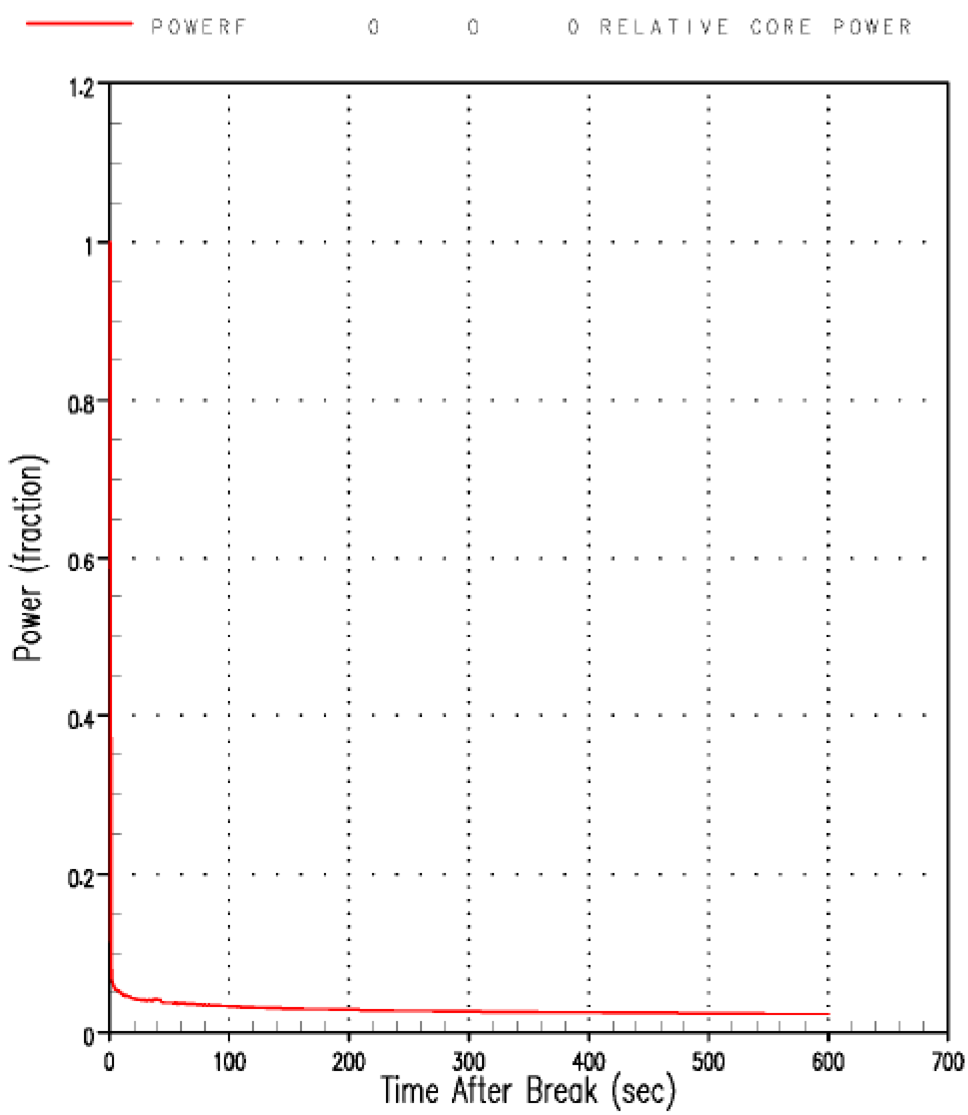


Figure 14.5-15
2.6 INCH BREAK- CLADDING TEMPERATURE
AT PCT NODE

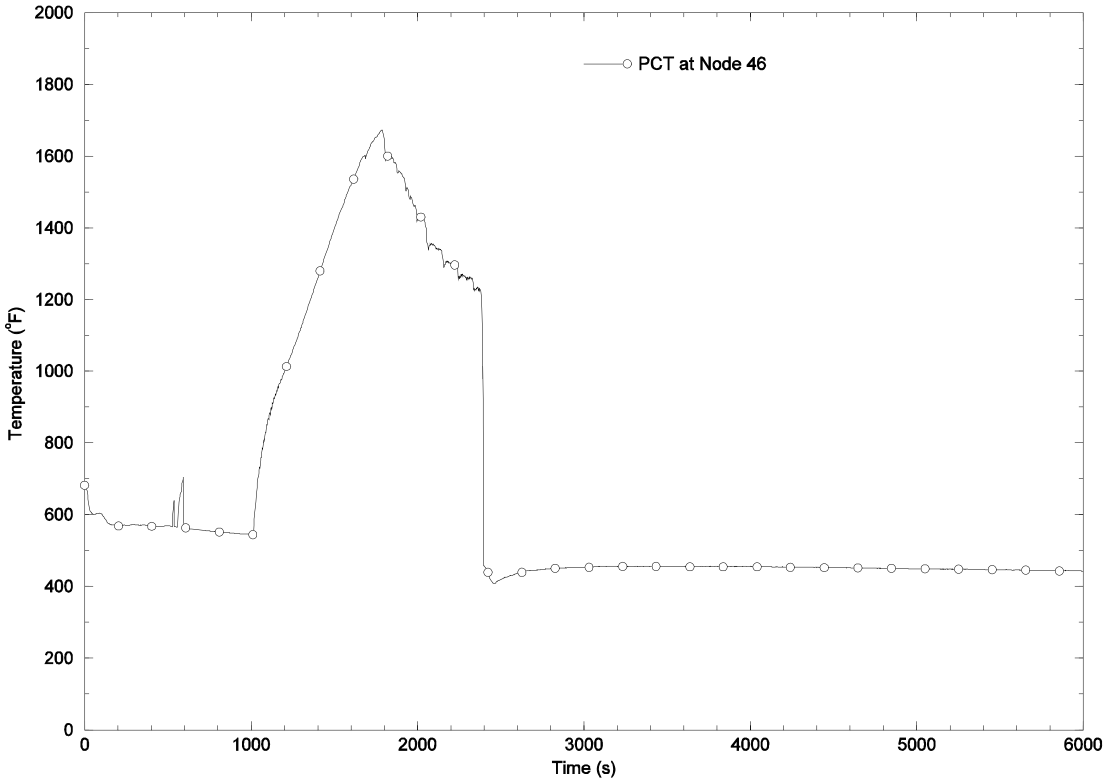


Figure 14.5-16
2.6 INCH BREAK- BREAK FLOW RATE

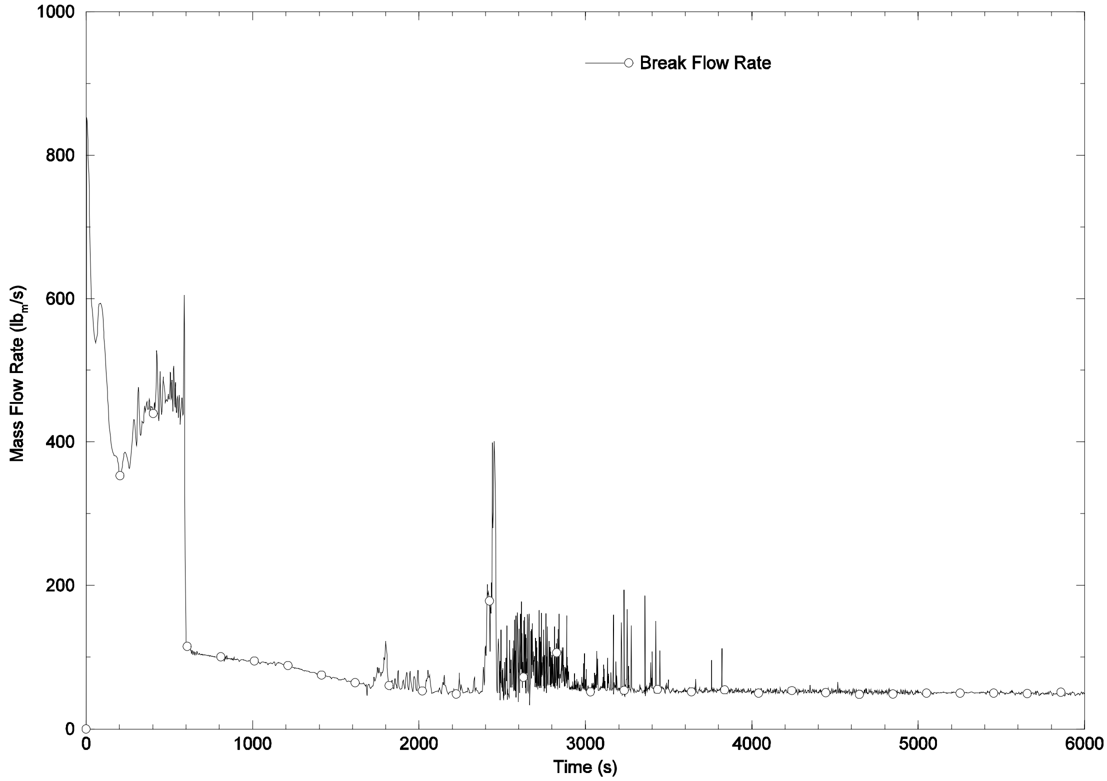


Figure 14.5-17
2.6 INCH BREAK - BREAK VOID FRACTION

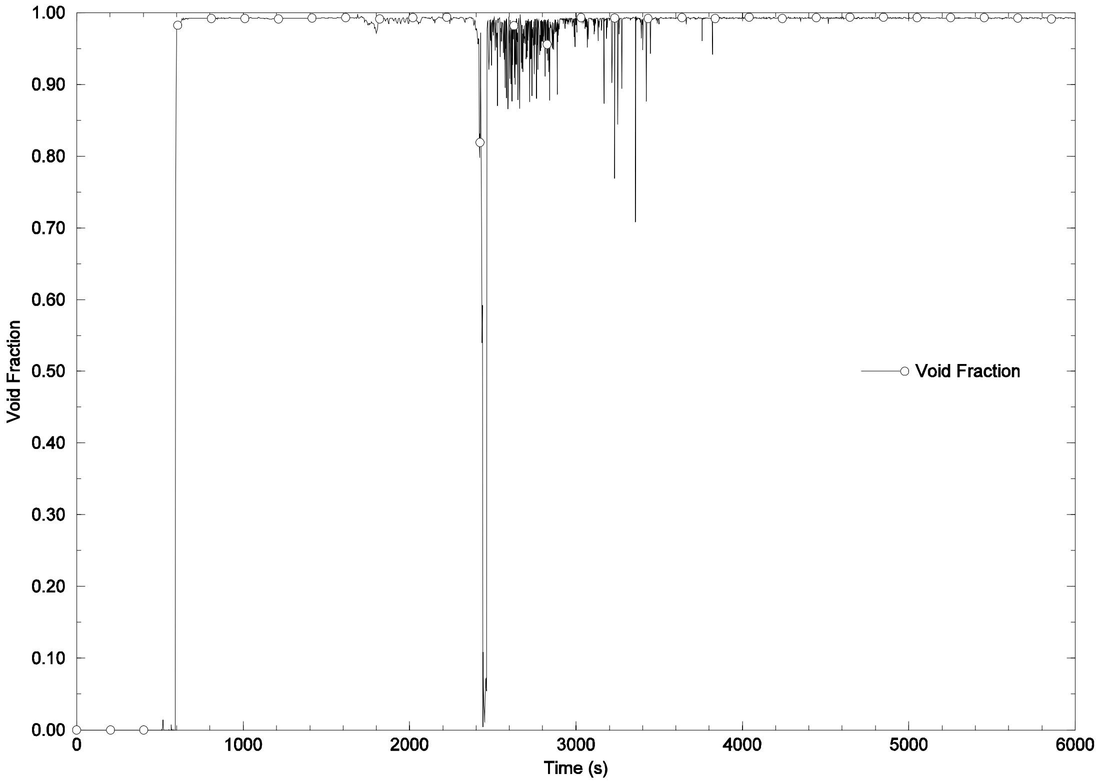


Figure 14.5-18
2.6 INCH BREAK - SYSTEM PRESSURES

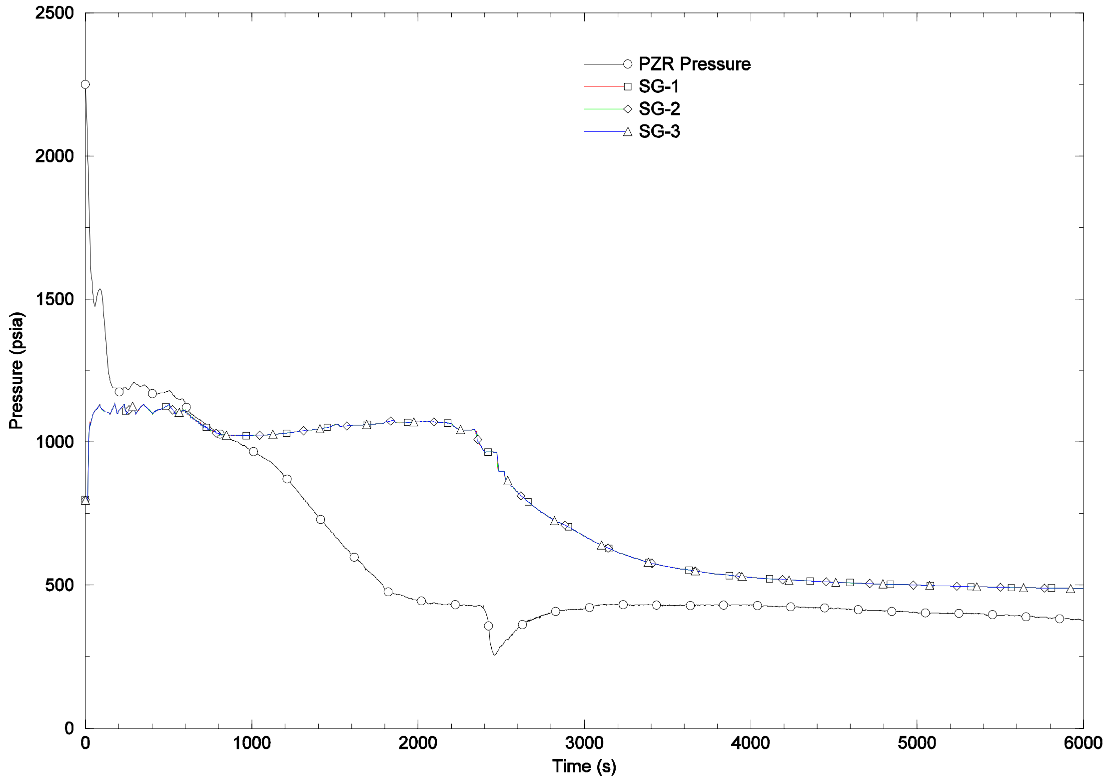


Figure 14.5-19
2.6 INCH BREAK - REACTOR POWER

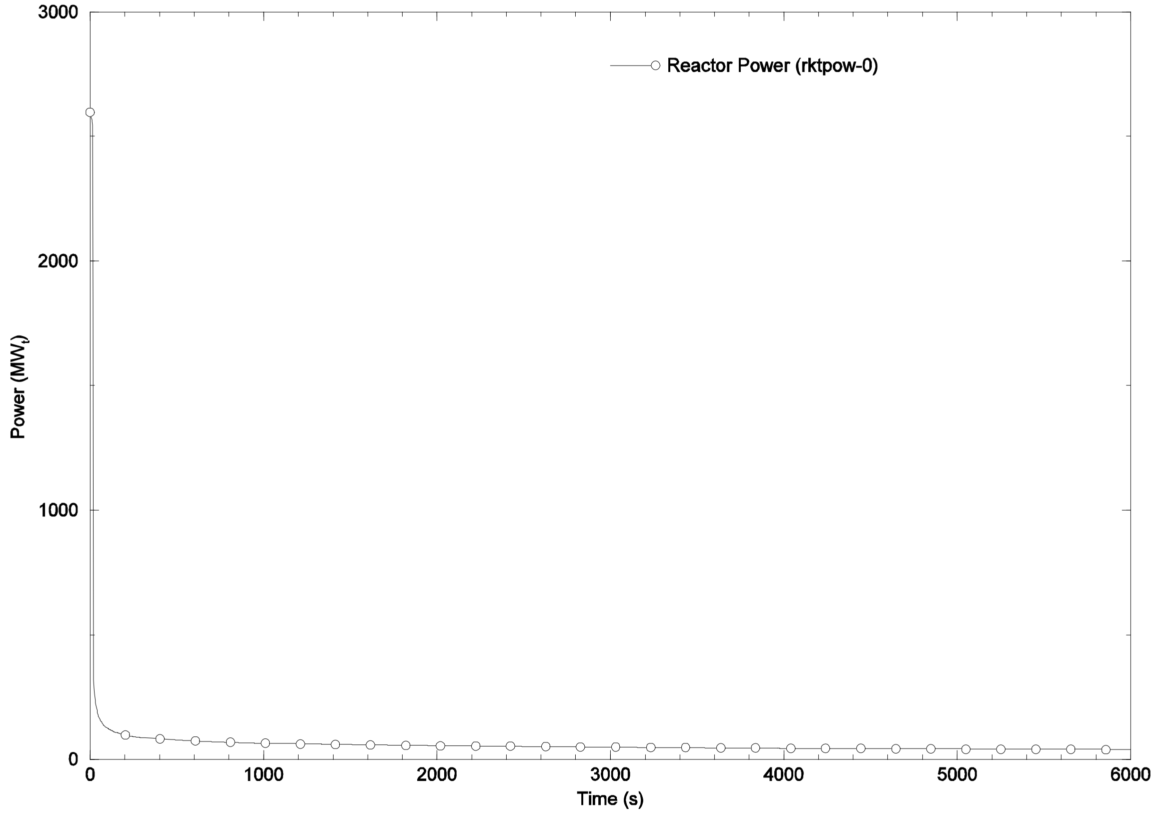


Figure 14.5-20
2.6 INCH BREAK - RCS AND RV MASSES

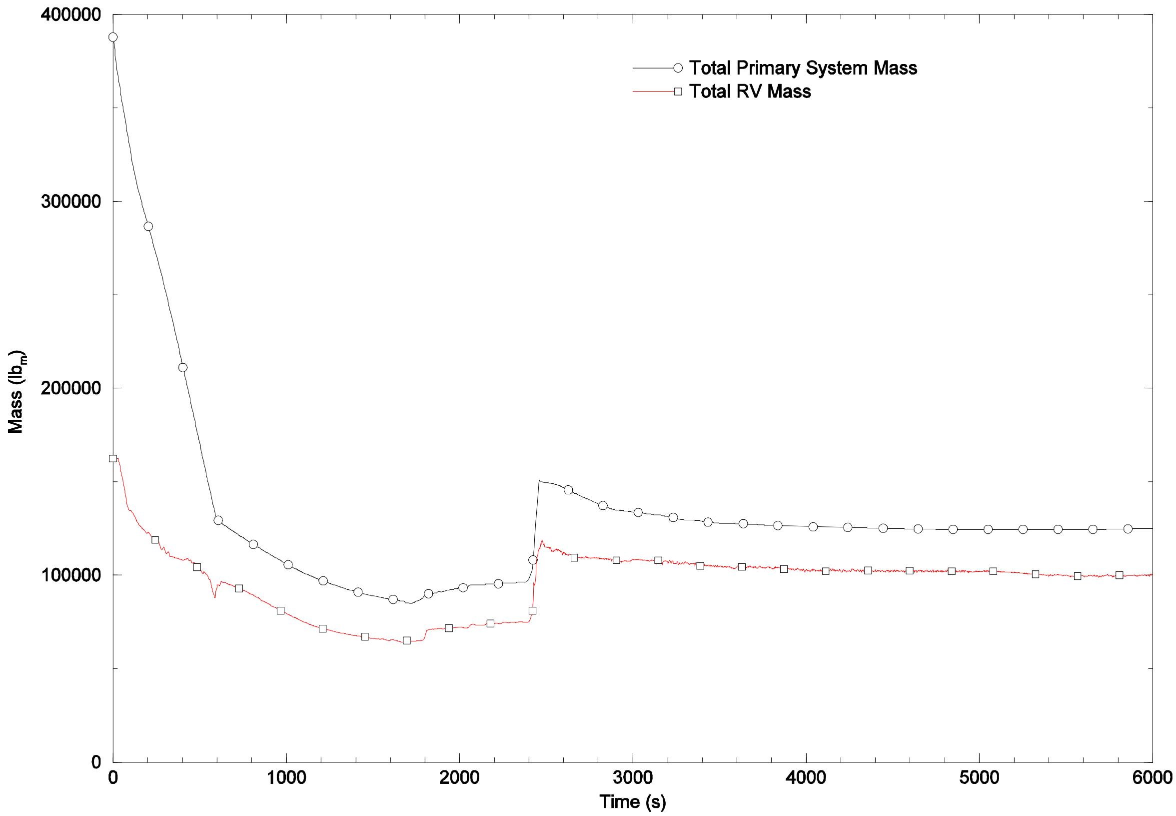


Figure 14.5-21
2.6 INCH BREAK - DOWNCOMER LEVEL

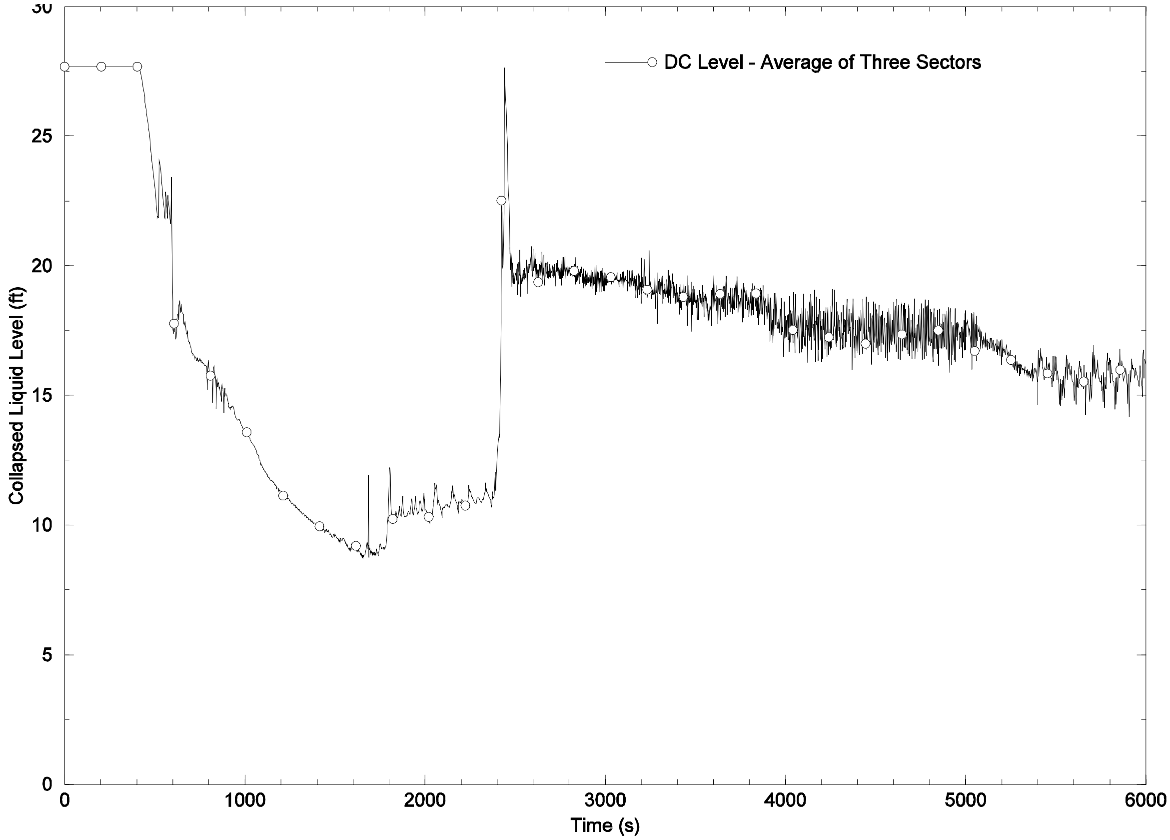


Figure 14.5-22
2.6 INCH BREAK - HOT ASSEMBLY COLLAPSED LEVEL

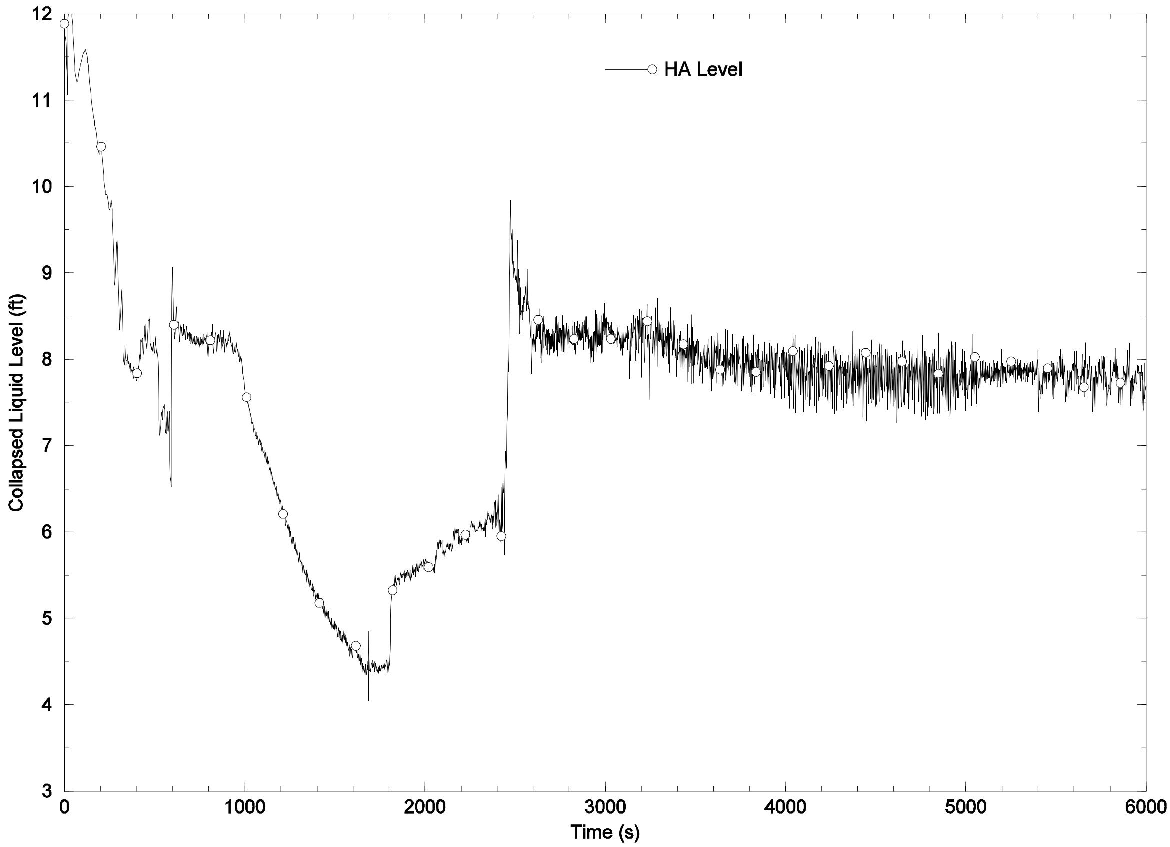


Figure 14.5-23
2.6 INCH BREAK - HOT ASSEMBLY MIXTURE LEVEL

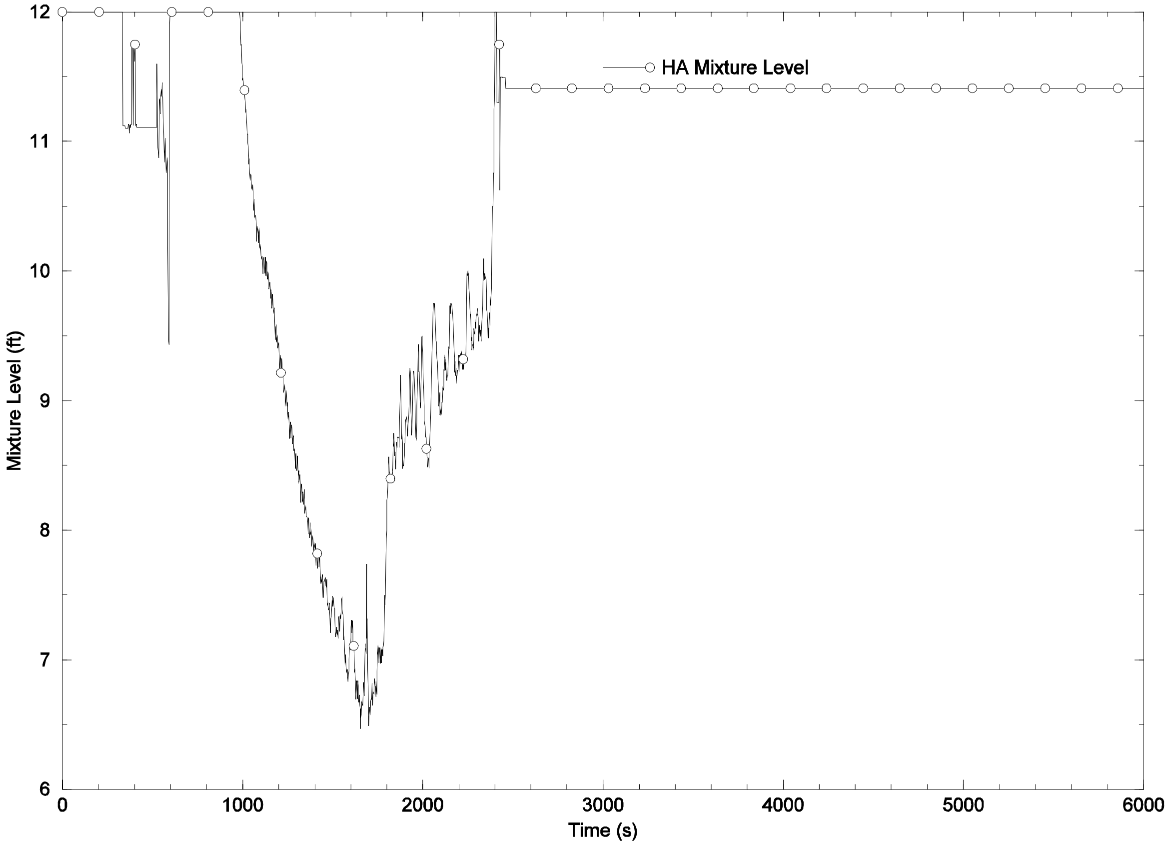


Figure 14.5-24
2.6 INCH BREAK - COLD LEG MASS FLOW RATES

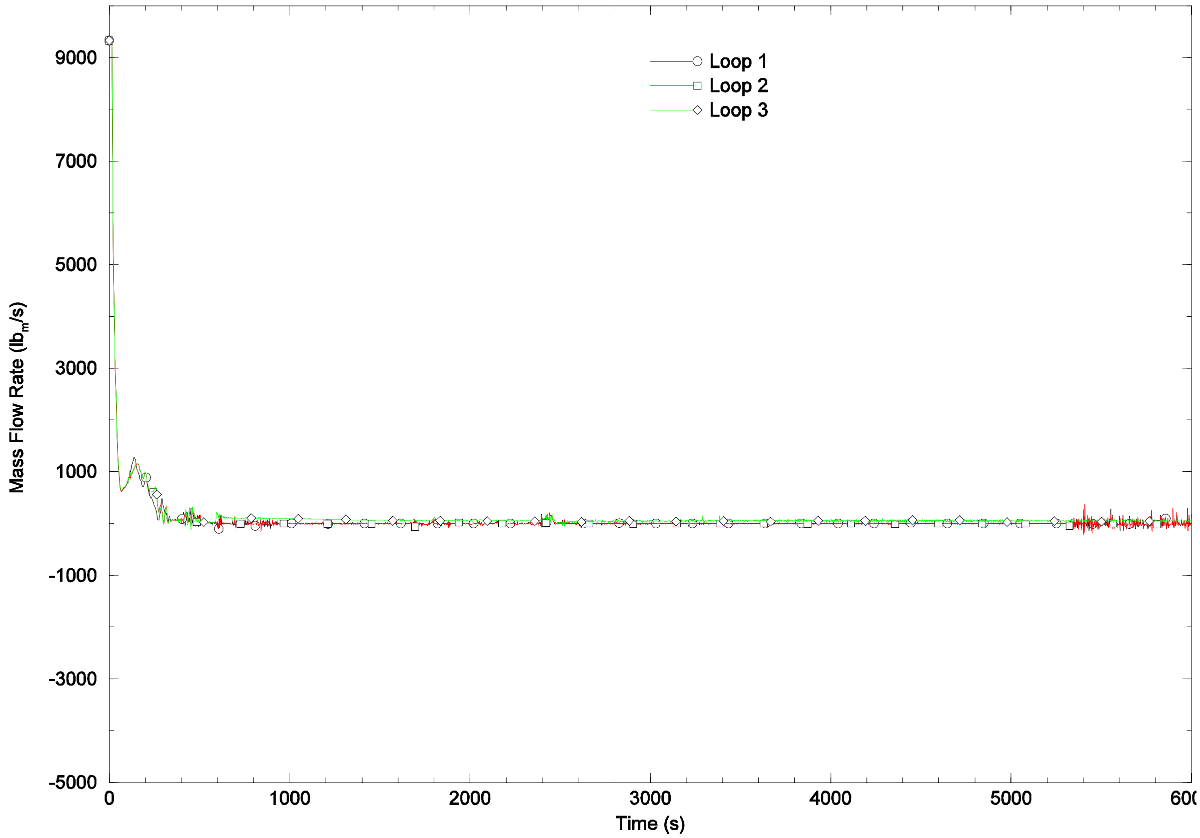


Figure 14.5-25
2.6 INCH BREAK - HHSI MASS FLOW RATES

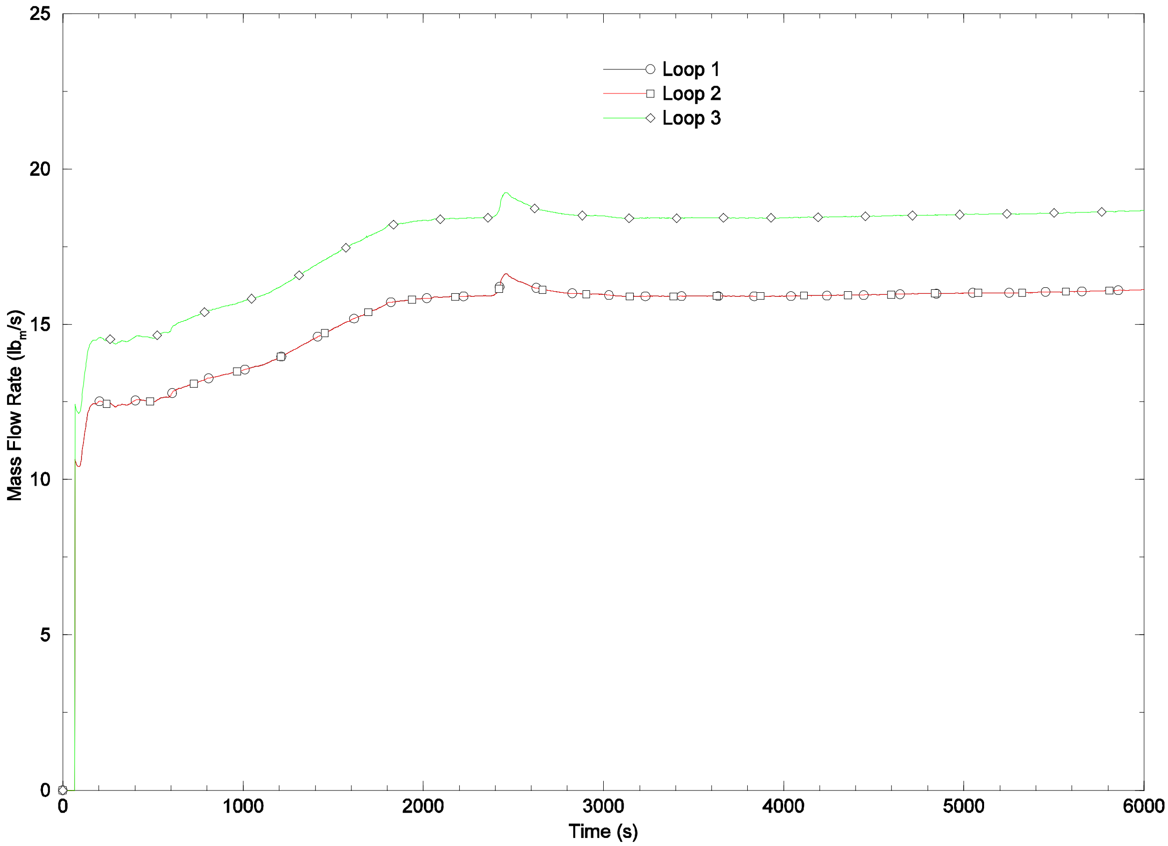


Figure 14.5-26
2.6 INCH BREAK - LHSI MASS FLOW RATES

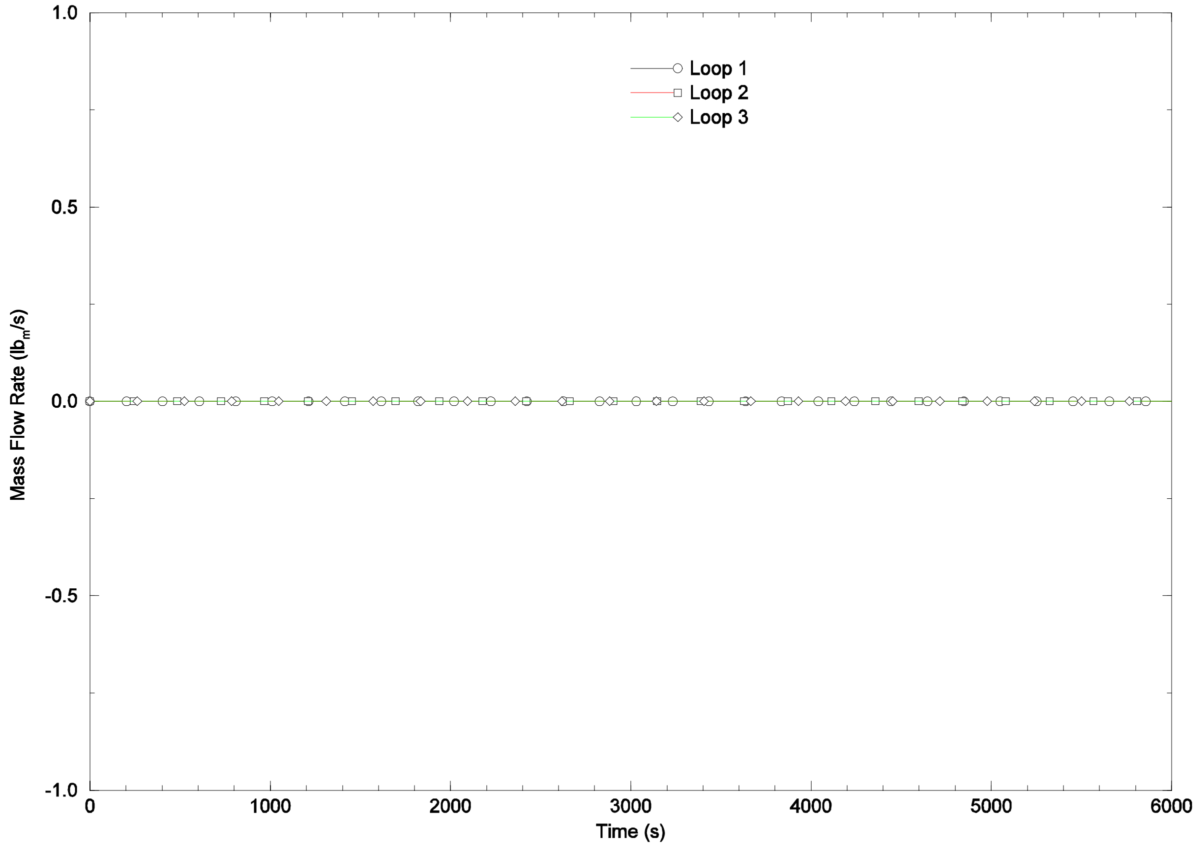


Figure 14.5-27
2.6 INCH BREAK - ACCUMULATOR MASS FLOW RATES

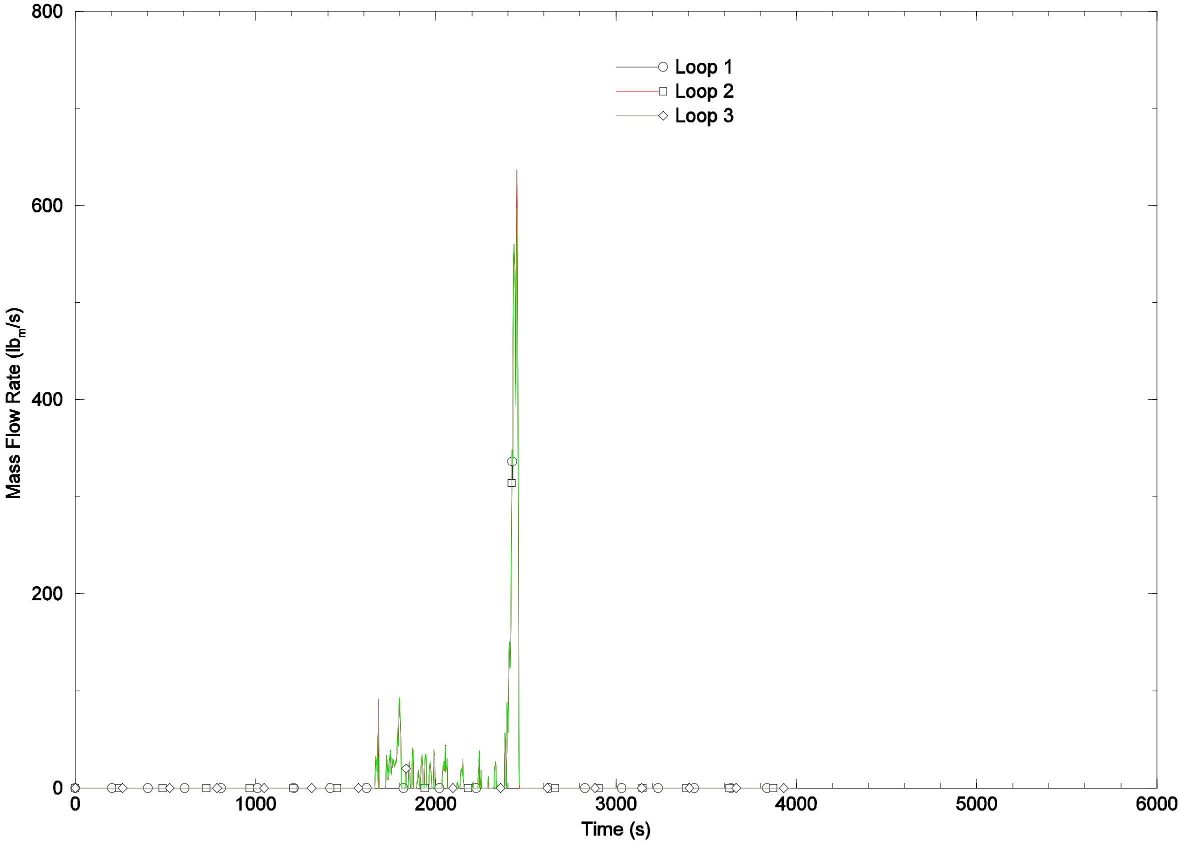


Figure 14.5-28
2.6 INCH BREAK - LOOP SEAL UPSIDE COLLAPSED LEVELS

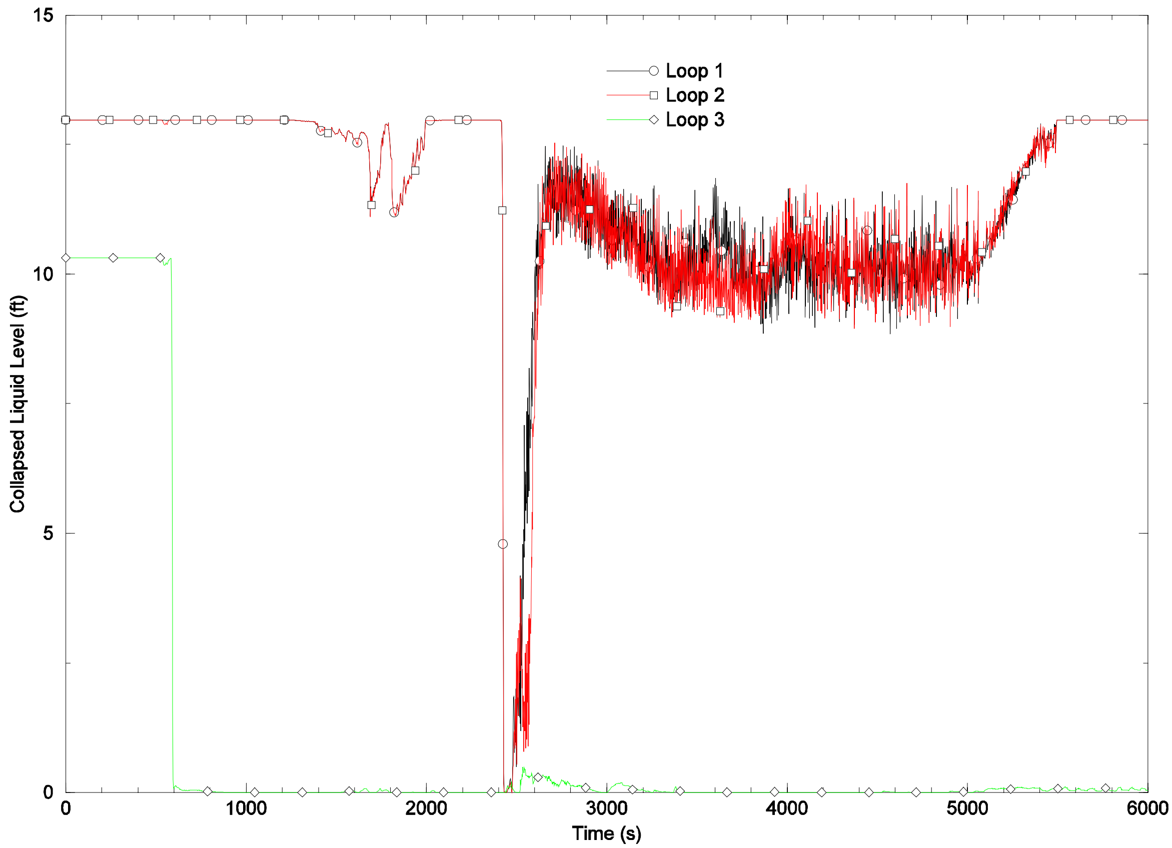


Figure 14.5-29
2.6 INCH BREAK - SG UPSIDE TUBE COLLAPSED LEVEL

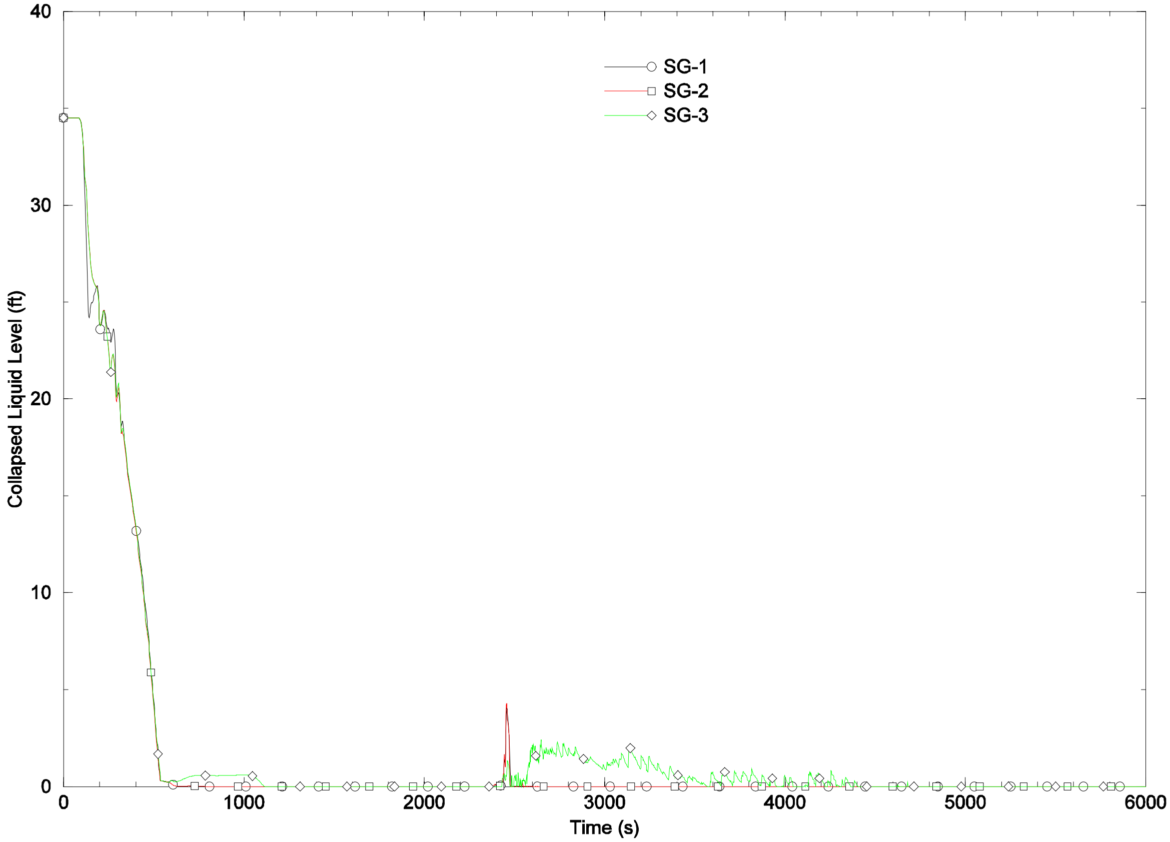


Figure 14.5-30
2.6 INCH BREAK - SECONDARY MASS

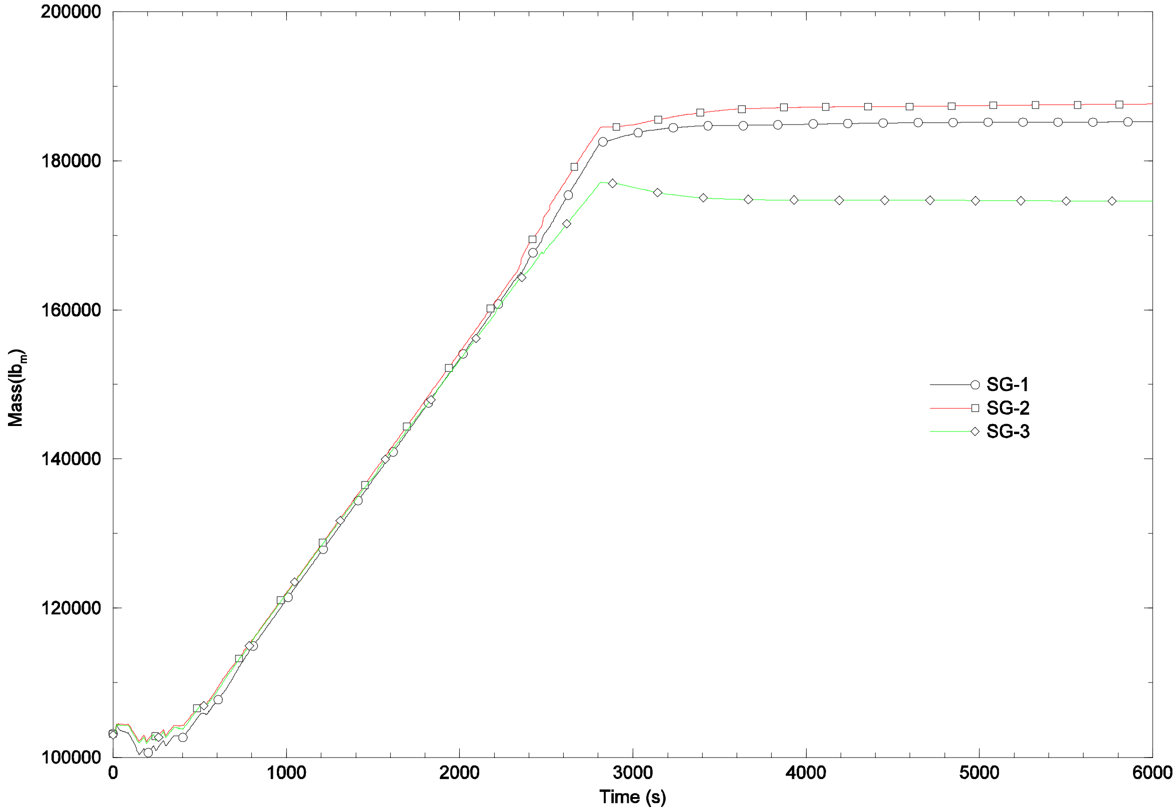


Figure 14.5-31
2.6 INCH BREAK - MFW MASS FLOW RATES

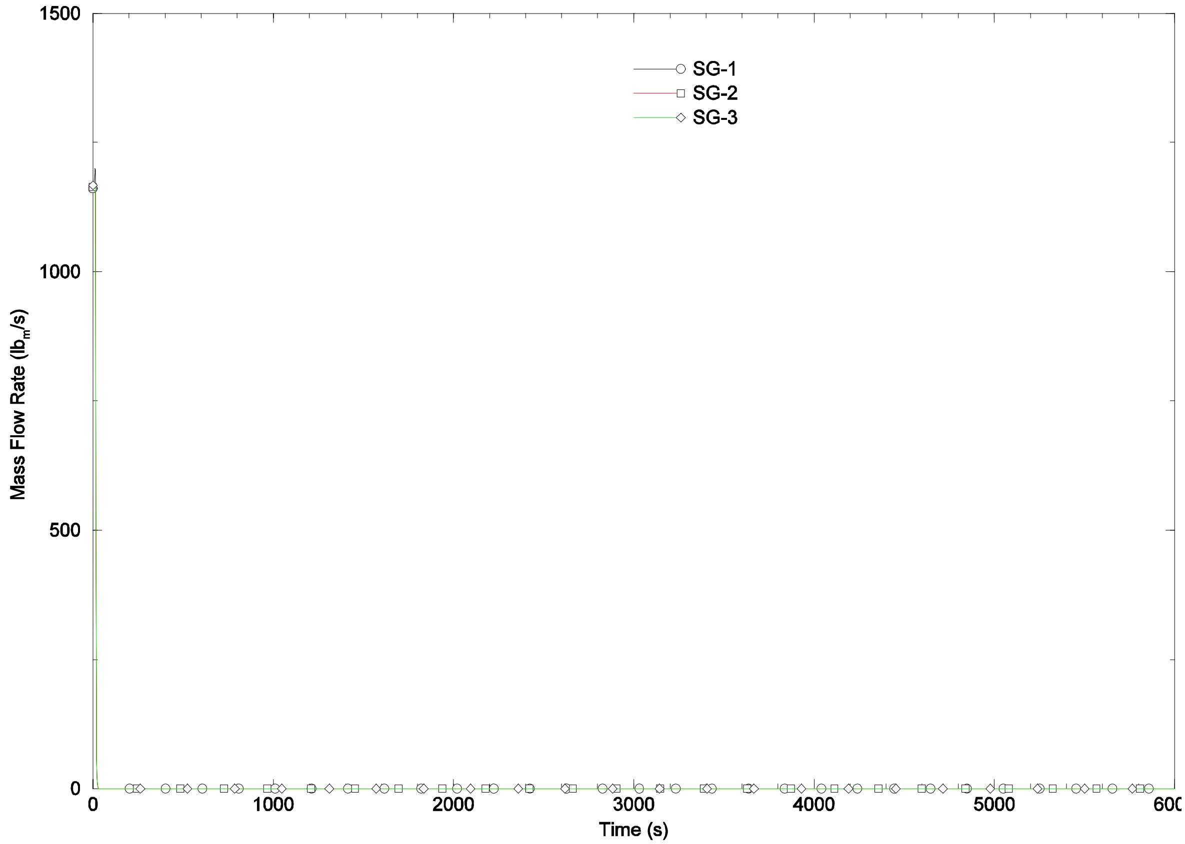


Figure 14.5-32
2.6 INCH BREAK - AFW MASS FLOW RATES

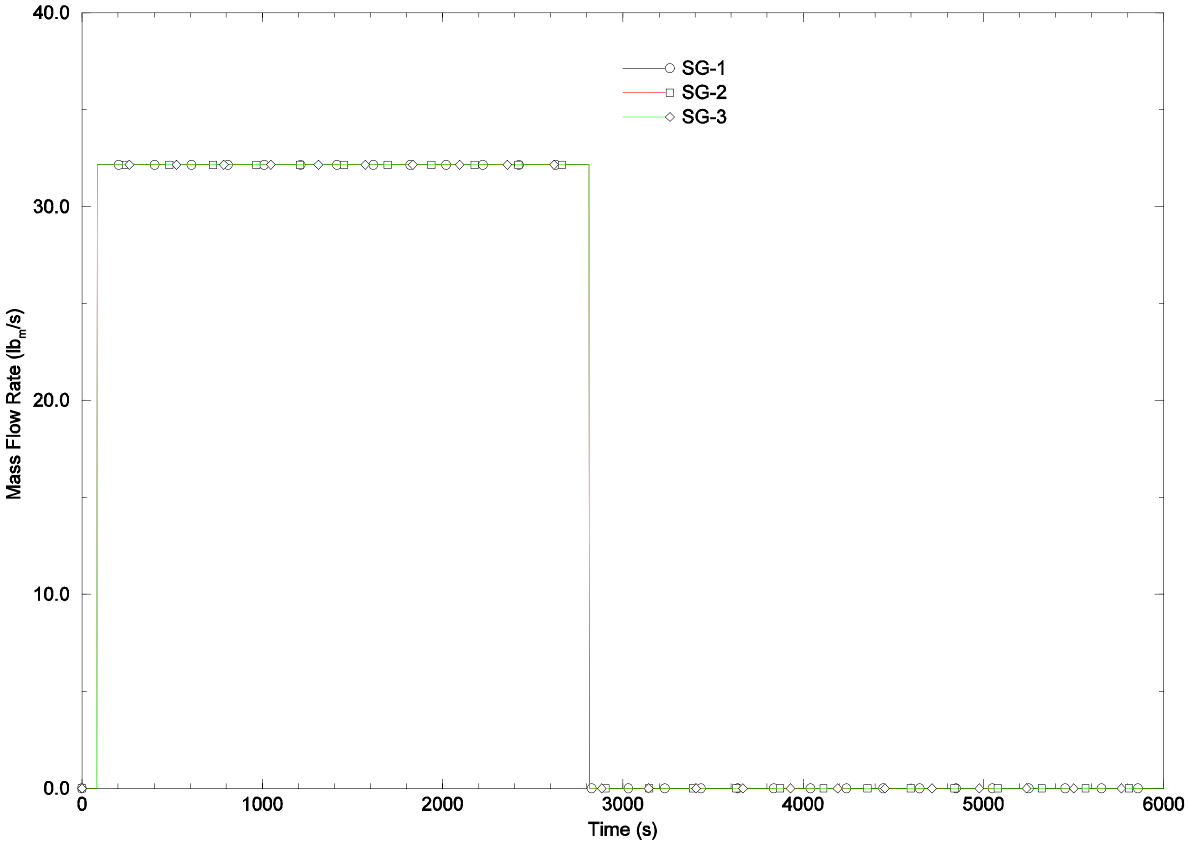


Figure 14.5-33
2.6 INCH BREAK - MSSV MASS FLOW RATES

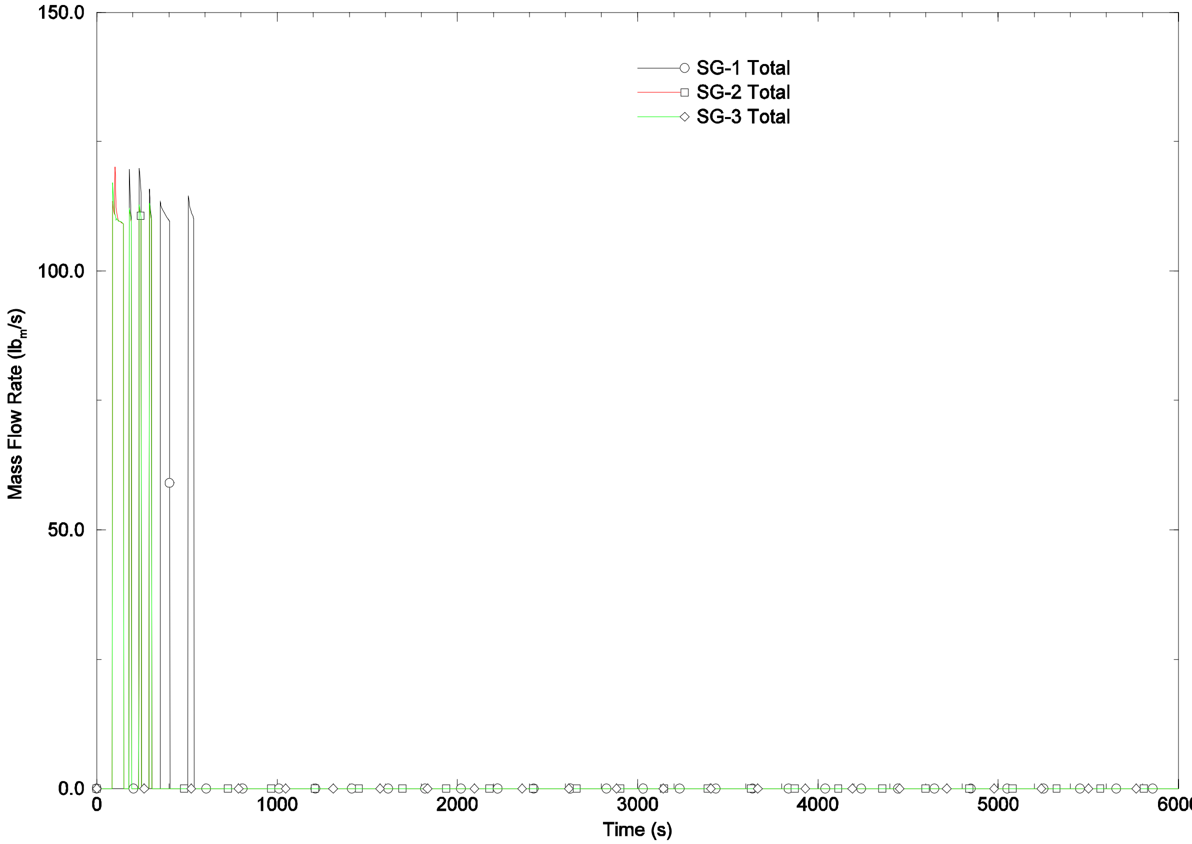


Figure 14.5-34
DELETED

Figure 14.5-35
DELETED

Figure 14.5-36
DELETED

Figure 14.5-37
DELETED

Figure 14.5-38
DELETED

Figure 14.5-39
DELETED

Figure 14.5-40
DELETED

Figure 14.5-41
DELETED

Figure 14.5-42
DELETED

Figure 14.5-43
DELETED

Figure 14.5-44
DELETED

Figure 14.5-45
DELETED

Figure 14.5-46
DELETED

Figure 14.5-47
DELETED

Figure 14.5-48
DELETED

Figure 14.5-49
DELETED

Figure 14.5-50
DELETED

Figure 14.5-51
DELETED

Figure 14.5-52
DELETED

Figure 14.5-53
DELETED

Figure 14.5-54
DELETED

Figure 14.5-55
DELETED

Figure 14.5-56
DELETED

Figure 14.5-57
DELETED

Figure 14.5-58
DELETED

Figure 14.5-59
DELETED

Figure 14.5-60
DELETED

Figure 14.5-61
DELETED

Figure 14.5-62
DELETED

Figure 14.5-63
DELETED

Figure 14.5-64
DELETED

Figure 14.5-65
DELETED

Figure 14.5-66
DELETED

Figure 14.5-67
DELETED

Figure 14.5-68
DELETED

Figure 14.5-69
DELETED

Figure 14.5-70
DELETED

Figure 14.5-71
DELETED

Figure 14.5-72
DELETED

Figure 14.5-73
DELETED

Figure 14.5-74
DELETED

Figure 14.5-75
LOFT SEMISCALE VESSEL BLOWDOWN RUN #522

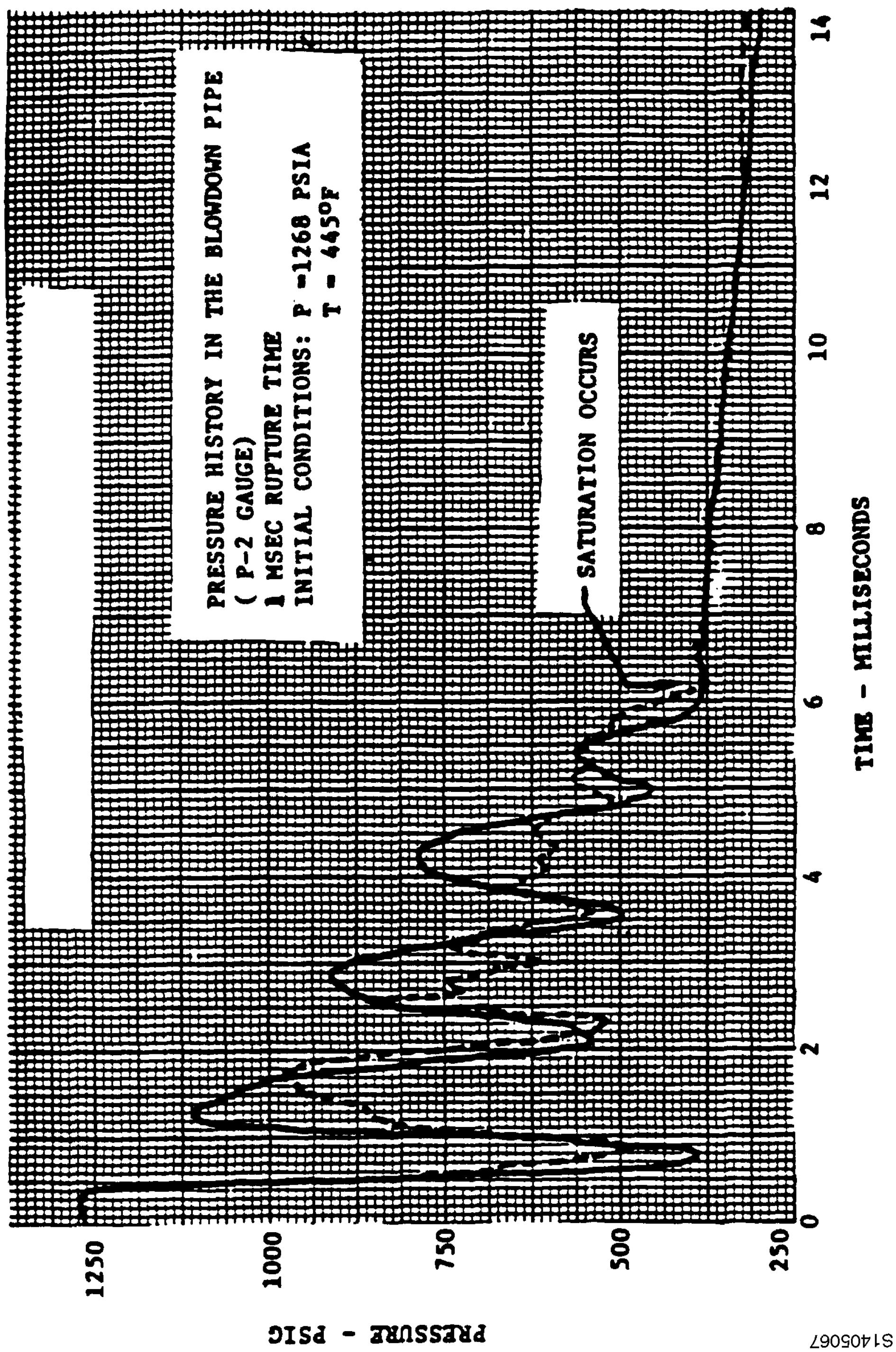
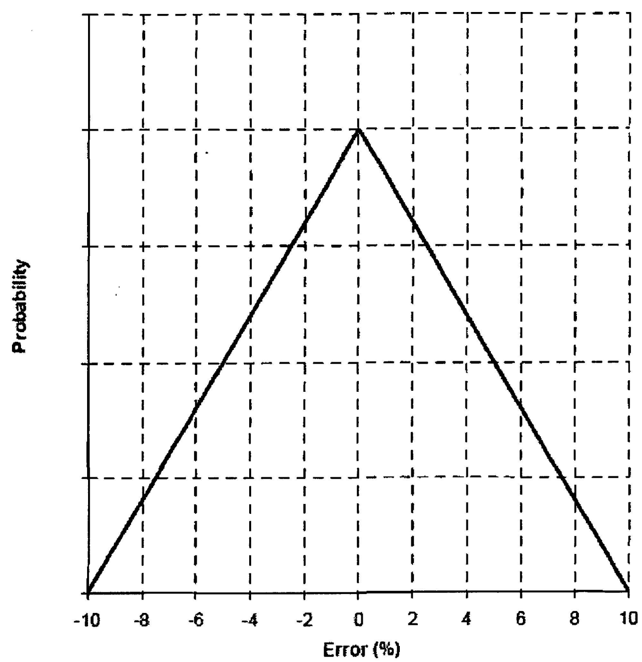
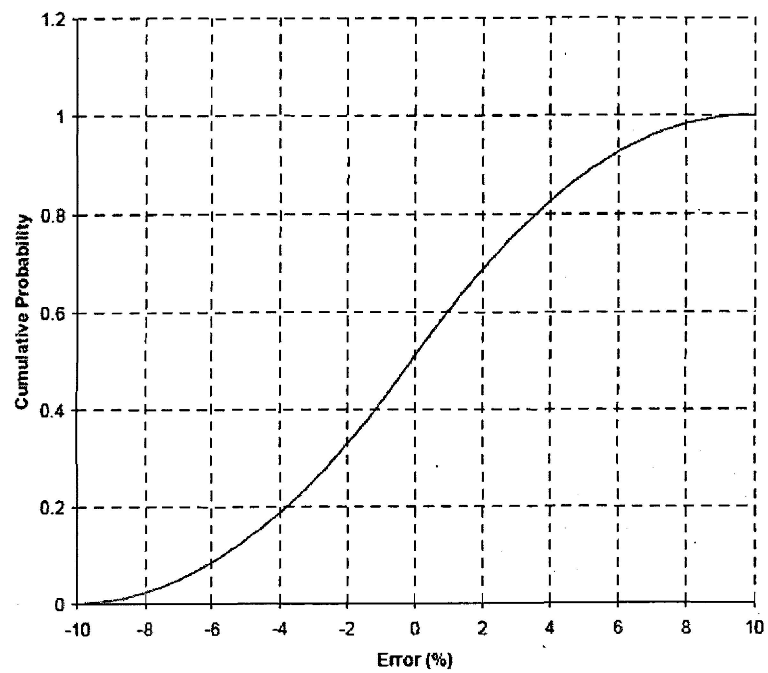


Figure 14.5-76
WECAN REACTOR EQUIPMENT SYSTEM MODEL





ANSYS: Westinghouse upgraded/ refined computer analysis by converting the Reactor Equipment System Model (RESM) from WECAN computer code to ANSYS computer code during the upflow conversion analysis. See Section 14.5.3.4.1 for detailed description of the model.

Appendix 14A
Radiation Sources

Intentionally Blank

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

APPENDIX 14A RADIATION SOURCES

14A.1 INTRODUCTION

This appendix presents the quantities of radioactive isotopes present in the core and the fuel rod gap. A general discussion of the derivations is also provided.

14A.2 TOTAL ACTIVITY IN THE CORE

The total core activity calculation is consistent with TID 14844 and data from ORNL-2127 (Reference 1). Numerical values for certain significant isotopes are given in Table 14A-1.

14A.3 ACTIVITY IN THE FUEL ROD GAP

The gap activity is computed based on buildup in the fuel from the fission process and diffusion to the fuel rod gap at rates dependent on the operating temperature. For analysis, the fuel pellets are considered divided into five concentric rings, each with release rate dependent on the mean fuel temperature within that ring. The diffusing isotope is assumed present in the gas gap when it has diffused to the boundary of its ring.

The diffusion coefficient, D', for Xe and Kr in UO_2 varies with temperature in accordance with the following expression:

$$D'(T) = D'(1673)\exp\left[-\frac{E}{R}\left(\frac{1}{T} - \frac{1}{1673}\right)\right]$$

Where:

E = activation energy

D'(1673) = diffusion coefficient at 1673 K = 1×10^{-11} sec^{-1}

T = temperature, K

R = gas constant

The above expression is valid for temperatures above 1473 K. Below 1473 K, fission gas release occurs, mainly by two temperature-independent phenomena, recoil and knock-out, and is predicted by using D' at 1473 K. The value used for D'(1673 K), based on data at burnups greater than 10^{19} fissions/cc, accounts for possible fission gas release by other mechanisms and pellet cracking during irradiation.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

The diffusion coefficient for iodine isotopes is assumed to be the same as for Xe and Kr. Toner and Scott (Reference 2) observed that iodine diffuses in UO_2 at about the same rate as Xe and Kr and has about the same activation energy. Data surveyed and reported by Belle (Reference 3) indicate that iodine diffuses at slightly slower rates than do Xe and Kr.

For a full core cycle at 2546 MWt, the above analysis results in a pellet-clad gap activity of less than 3% of the dose equivalent equilibrium core iodine inventory. The noble gas activity present in the pellet-clad gap is about 2.5% of the core inventory.

The percentage of the total core activity present in the gap for each isotope is also listed in Table 14A-1.

The core temperature distribution used in this analysis is presented in Table 14A-2.

14A REFERENCES

1. J. O. Blomeke and Mary F. Todd, *Uranium-235 Fission-Product Production as a Function of Thermal Neutron Flux, Irradiation Time and Decay Time,* ORNL-2127, August 19, 1957.
2. D. F. Toner and J. S. Scott, "Fission Product Release From UO_2," *Nuclear Safety*, Vol. 3, No. 2, December 1961.
3. J. Belle, *Uranium Dioxide: Properties and Nuclear Applications*, Naval Reactors, Division of Reactor Development, United States Atomic Energy Commission, 1961.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 14A-1
CORE AND GAP ACTIVITY

Isotope	Ci in the core ($\times 10^7$)	Ci in the gap ($\times 10^5$)
I-131	6.27	16.9
I-132	9.57	3.1
I-133	14.4	14.0
I-134	17.3	3.53
I-135	12.8	7.08
Kr-85	.092	1.46
Xe-133	14.3	32.2
Xe-133m	.388	.602
Xe-135	5.43	.437

Note: Operation at 2546 MWt for 500 days. Temperature distribution specified in Table 14A-2.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 14A-2
CORE TEMPERATURE DISTRIBUTION

Percent of Core Fuel Volume Above Given the Temperature	Local Temperature, °F
0.01	4100
0.40	3700
2.20	3300
5.90	2900
11.30	2500

Intentionally Blank

Appendix 14B
Effects of Piping System Breaks Outside Containment

Intentionally Blank

APPENDIX 14B EFFECTS OF PIPING SYSTEM BREAKS OUTSIDE CONTAINMENT

14B.1 INTRODUCTION

14B.1.1 Appendix Coverage and Summary

This appendix is based on Appendix D to the initial FSAR and provides the response to a Commission letter dated December 18, 1972 (Reference 1), which contained a document entitled *General Information Required for Consideration of the Effects of a Piping System Break Outside Containment* (later revised in January 1973).

Since Surry Units 1 and 2 are similar in design, and to avoid unnecessary repetition, the analysis within this Appendix is oriented to Unit 2. However, wherever Unit 1 is unique with respect to Unit 2, an additional analysis is made for the unique portions.

This appendix presents an analysis of the consequences of postulated pipe failures outside the containment. In addition to the direct effects on safety resulting from the postulated break of a high-energy line, it is shown in this analysis that Surry Units 1 and 2 can be shut down and maintained in a shutdown condition. The postulated break of a pipe is shown not to negate any safety function as a result of the postulated failure.

The analysis ensures that the Commission's General Design Criterion 4 is met, i.e., that all structures, systems, and components important to safety are designed to accommodate the effects of and are compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents (LOCAs). These structures, systems, and components are protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result in equipment failures and from events and conditions outside the nuclear power unit.

14B.1.2 Appendix Organization

The sectional organization of this Appendix is delineated in Figure 14B-1.

The approach used to analyze the consequences of pipe failure is to identify and locate the high-energy sources, identify and locate the safety-related targets, and determine and evaluate the physical effects. The criteria for determining pipe breaks and methods of analysis are presented in Section 14B.2. The identification and location of high-energy systems are found in Section 14B.3. The safety-related and shutdown equipment is identified, and the location listed in Section 14B.4. Calculation results and the evaluation of the physical effects from a pipe system break are found in Section 14B.5. The conclusions are found in Section 14B.7.

14B.2 CRITERIA FOR PIPE BREAKS AND METHODS FOR ANALYSIS

14B.2.1 General Discussion

High-energy systems that require analysis for the consequences of pipe breaks are identified based on the fluid in the pipe, and the pressure and temperature during normal station operation.

In pressurized water reactors, the fluids are water, steam, and water solutions. High-pressure nonflashing gas lines are not included in this analysis.

The temperatures and pressures used for determination of high-energy systems are the maximum normal operating temperatures and pressures. The type of analysis that is required is based on the temperature and pressure conditions as shown in Figure 14B-2. The lines that are both high-temperature and high-pressure are analyzed for pipe whip and environmental effects. The pipes that are low-pressure and high-temperature, or low-temperature and high-pressure, are postulated to crack and are analyzed for environmental effects.

The analysis of these effects (environmental, pipe whip, steam jets, etc.) involves consideration of the source and the target. The source includes the postulated pipe failure and the resulting reactions of the failure. The target includes components or systems that are considered essential in shutting down and maintaining the reactor in a safe-shutdown condition in the event of a postulated break outside containment of a pipe containing high-energy fluid, and which provide protective functions such that a loss of redundancy can be permitted but a loss of function cannot be permitted. The approach taken involved the determination of the effects of the source on the target.

After the high-energy lines are identified in accordance with the above definition, the function of each line is determined. Failure of lines that do not serve a safety function do not require the plant to be shut down. The criterion to which these lines are analyzed is that all safety functions must be protected. Failure of one out of two redundant components is acceptable if the safety function is not degraded. It is assumed that the plant must be shut down to repair damage to safety equipment in accordance with the Technical Specifications.

Failures in lines that serve a safety function require the plant to be shut down and maintained in a shutdown condition. The criterion under which these lines were analyzed is that all redundant components required to operate to recover from this failure are to be protected, including all redundant equipment required to bring the plant to shutdown and to maintain the plant in the shutdown condition.

To analyze the consequences of the postulated break, the targets must be identified. Targets are identified on the various drawings within this appendix.

After the high-energy break points and targets are located, the consequences of pipe whip and jet impingement are determined. The criteria and methods of analysis for determining these effects are discussed below. As a part of the analysis of each break point, it is determined that either the consequences are acceptable, or pipe whip protection and/or jet impingement protection is required.

14B.2.2 Criteria for Pipe Breaks and Cracks

14B.2.2.1 **Definition of High-Energy Lines**

Design-basis pipe breaks are postulated in piping for which the maximum operating pressure exceeds 275 psig and the maximum operating temperature equals or exceeds 200°F. The critical crack size is taken to be one-half the pipe diameter in length (d/2) and one-half the wall thickness in width (t/2). Pipe cracks (d/2 x t/2) are postulated in piping for which either the operating pressure exceeds 275 psig or the operating temperature equals or exceeds 200°F. If both operating pressure and temperature are below these values, breaks and cracks are not postulated (Figure 14B-2).

Operating temperature and pressure are defined as the maximum temperature and pressure in the piping system, during occurrences that are expected frequently or regularly in the course of power operation, start-up, shutdown, standby, refueling, or maintenance of the plant.

Protection from pipe whip is not provided if any of the following conditions exists:

1. The piping is physically separated by protective barriers or is otherwise isolated from structures, systems, or components important to safety, or is restrained from whipping by plant design features such as concrete encasement.
2. Following a single break, the unrestrained pipe movement of either end of the broken pipe in any possible direction about a plastic hinge formed at the nearest pipe whip restraint cannot impact any structure, system, or component important to safety.
3. The internal energy level associated with the whipping pipe can be demonstrated to be insufficient to impair the safety function of any structure, system, or component to an unacceptable level.

   The internal fluid energy level associated with the pipe break reaction may take into account any line restrictions (e.g., flow limiters) between the pressure source and break location, and the effects of either single-ended or double-ended flow conditions, as applicable. The energy level in a whipping pipe may be considered as insufficient to break an impacted pipe of equal or greater nominal pipe size and equal or heavier wall thickness.

14B.2.2.2 **Pipe Break Criteria**

Design-basis break locations are postulated in accordance with the following pipe whip protection criteria. However, where pipes carrying high-energy fluids are routed in the vicinity of structures and systems necessary for safe shutdown of the nuclear plant, supplemental protection of these structures and systems is provided to cope with the environmental effects (including effects of jet impingement) of a single postulated open crack at the most adverse location with regard to these essential structures and systems, the length of the crack being chosen not to exceed the critical crack size.

1. ASME Section III, Class I piping breaks are postulated to occur at certain locations in each piping run or branch run. Piping is defined as a pressure-retaining component consisting of straight or curved pipe and pipe fittings (e.g., elbows, tees, and reducers). A piping run is defined as piping that interconnects components such as pressure vessels, pumps, and rigidly fixed valves that may act to restrain pipe movements beyond the restraint required for design thermal displacement. A branch run differs from a piping run only in that it originates at a piping intersection, as a branch of the main pipe run.

   The postulated locations of piping breaks are:

   a. The terminal ends.

   b. Any intermediate locations between terminal ends where the primary-plus-secondary stress intensities S_n (circumferential or longitudinal) derived on an elastically calculated basis under the loadings associated with one-half of the safe shutdown earthquake and operational plant conditions exceed 2.0 S_m for ferritic steel and 2.4 S_m for austenitic steel.

      Operational plant conditions include normal reactor operation, upset conditions (anticipated operational occurrences), and testing conditions. S_m is the design stress intensity as specified in Section III of the ASME Code.

   c. Any intermediate locations between terminal ends where the cumulative usage factor (U) derived from the piping fatigue analysis and based on all normal, upset, and testing plant conditions exceeds 0.1.

      U is the cumulative usage factor as specified in Section III of the ASME Code.

   d. At intermediate locations in addition to those determined by l.a and l.b above, selected on a reasonable basis as necessary to provide protection. As a minimum, there are two intermediate locations for each piping run or branch run.

2. ASME Section III, Class 2 and 3, and ANSI-B31.1.0 (1967 Edition) piping breaks are postulated to occur at the following locations in each piping run or branch run:

   a. The terminal ends.

   b. Any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with seismic events and operational plant conditions exceed 0.8 (S_h + S_A), or the expansion stresses exceed 0.8 S_A.

S_h is the stress calculated by the rules of NC-3600 and ND-3600 for Class 2 and 3 components, respectively, of the ASME Code, Section III, Winter 1972 Addenda. S_A is the allowable stress range for expansion stress calculated by the rules of NC-3600 of the ASME Code, Section III-1971, or the USA Standard Code for Pressure Piping, ANSI B31.1.0-1967.

c. Intermediate locations in addition to those determined by 2.b above selected on a reasonable basis as necessary to provide protection. As a minimum, there are two intermediate locations for each piping run or branch run, selected on the basis of maximum combined primary and secondary stress. For nonseismic piping systems, the intermediate locations are selected on the basis of maximum thermal stress.

3. For systems meeting maximum operating conditions of either pressures greater than 275 psig or temperatures greater than 200°F, piping cracks were postulated at the most adverse points with respect to targets.

14B.2.2.3 Pipe Break Orientation

The criteria used to determine the pipe break orientation at the break locations as specified in Section 14B.2.2.2 above are equivalent to the following:

1. Longitudinal breaks in piping runs and branch runs, 4-inch nominal pipe size and larger, and/or
2. Circumferential breaks in piping runs and branch runs exceeding 1-inch nominal pipe size.

A tee-joint that connects a branch run and main piping is not necessarily a break location for the main piping if it does not qualify as a high-stress and/or high cumulative usage factor location in this main piping run; however, at its welding junction to the branch run, which is a terminal point of the branch run, a break location has to be postulated.

If one of the computed stresses and/or cumulative usage factors of the various points of an elbow (tee or reducer) is high enough to be qualified as an intermediate break location, and the other(s) varies within ±l0% of it, all these points are considered as a single break location.

Longitudinal breaks are parallel to the pipe axis and oriented at any point around the pipe circumference. The break area is equal to the effective cross-sectional flow area upstream of the break location. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the direction normal to the pipe ends.

Circumferential breaks are perpendicular to the pipe axis, and the break area is equivalent to the internal cross-sectional area of the broken pipe. The dynamic (blowdown) forces resulting from a circumferential break act to separate the piping axially; there is no transverse force during a circumferential break event.

14B.2.3 Methods of Analysis and General Results

14B.2.3.1 **Whipping Pipes and Interactions With Concrete Walls**

The velocity of a whipping pipe is dependent on:

1. The blowdown forces.
2. The pipe, break geometry, and size.
3. The distance traveled.

A typical mathematical model is shown in Figure 14B-3. At time zero, before the break occurs, the system is in a state of stress due to internal pressure, but these pressure forces are in static equilibrium with the axial loads in the pipe. As the circumferential crack propagates, the load-carrying metal area decreases, so a force imbalance results (Figure 14B-3, Part A). The axial load at the break is assumed to drop linearly to zero in 1 millisecond. After the break, the forces exerted on the pipe by the fluid are determined by time-dependent pressure and momentum effects. The combined behavior of these two terms is equivalent to a pressure drop to 0.7 of the initial value after the passage of the decompression wave (Reference 2). A wave velocity, assumed to be 1600 fps, results in the forcing functions as shown in Figure 14B-3, Part B.

The results of the above analysis indicate that, during most of the pipe displacement, the applied forces are only 0.7 of the initial forces and that approximately 30% of the energy is dissipated by plastic deformation in the pipe before impact. Due to strain hardening and strain rate effects, a distinct hinge may not form, but rather an extended region of large plastic deformation occurs. The plastic hinge lengths are also determined by this analysis (Table 14B-1) for the initial condition of 1050 psi.

Effects from whipping pipes on concrete walls were analyzed as follows. The local crushing stiffness of the pipe elbow may be readily determined in the elastic range, but only with difficulty once plastic deformation begins. The case of the actual elliptical contact area between the pipe elbow and wall has been considered, as well as an idealized case in which the portion of the elbow near the contact area is modeled as an equivalent sphere. PISCES (Reference 3) computer runs indicate that once crushing (or denting) is initiated, a flat area forms on the elbow. (Without internal pressure, bounce-back or “oil canning” occurs.) The forces transmitted by the wall to the pipe occur mainly at the circumference of the contact area. Thus, analyses presented in the literature for the stiffness of a sphere intersected by a pipe with normal loading may be used to get an approximate stiffness (Reference 4).

The crushing resistance of the elbow is modeled as a spring (connected to ground) in the mathematical model. This is acceptable, since the great inertia of the wall prevents any appreciable movement prior to the moment that the peak forces occur. The peak force in this spring is the maximum load transmitted to the wall during the impact. The effects of the continuing blowdown forces and the inertia of the pipe away from the impact point are automatically included in the analysis. Typical examples of these peak forces as a function of impact velocity are plotted in Figure 14B-4.

Since the load is applied to the concrete wall in a short time compared to the natural period of a concrete wall, the application of a dynamic load factor of two is required when using static design equations. The model used for punch shear is shown in Figure 14B-5. The equation used for punching shear (Reference 5) in a concrete wall is:

$$F = 4\sqrt{f_c}d2\pi\left(r + \frac{d}{2}\right)$$

where:

F = applied force

f_c = compressive strength of concrete

d = wall thickness

r = radius of contact area

In all cases, wall thicknesses employed in normal plant construction are sufficient to stop whipping pipes.

14B.2.3.2 **Fluid Jets and Interactions With Reinforced-Concrete Walls**

14B.2.3.2.1 Assumptions

1. The pipe break location is very close to the pressure reservoir(s). The pressure drop in the pipe due to flow friction is negligible.
2. The total jet force remains constant throughout its traveling distance; i.e., the friction force between the jet stream and ambient air is negligible.
3. The jet stream is totally intercepted by the concrete wall.
4. The jet impingement is a suddenly applied load to the concrete wall.

14B.2.3.2.2 Jet Force

The maximum value of the initial jet pressure from a pipe break can be expressed as:

$$P_J = C_J P_o$$

where:

P_o = fluid pressure inside pipe

C_J = jet coefficient

$C_J = 1.26$ for steam

$C_J = 2.0$ for subcooled nonflashing water

(If the pressure drop due to friction is taken into consideration, the values of C_J can be reduced.)

The total jet force is then:

$F_J = P_J A$

where:

A = pipe break area $= \frac{\pi}{4} D_p^2$

D_p = inside diameter of pipe

As the jet stream progresses away from the pipe break area, the width of the jet increases with the axial distance. The angle of divergence is assumed to be 20 degrees (Reference 6).

14B.2.3.2.3 Punch Shear Failure of Concrete Wall

The punch shear failure mechanism of a concrete wall due to jet impingement from a pipe break is shown in Figure 14B-6. The failure of a concrete wall is a diagonal cracking along the surface of a truncated cone or pyramid around the jet impingement area. The area of the shearing surface is:

$A_s = \pi D_w W$

where:

$D_w = D_P + 2L \tan 10° + W$

W = wall thickness

L = distance between wall and pipe break location

Without shear reinforcement, the shear strength is:

$$V_c = 4\sqrt{f'_c}$$

where:

f'_c = specified compressive strength of concrete

The total shear resistance of the reinforced-concrete wall is:

$R = ø A_s V_c$

where:

ø = capacity reduction factor = 0.85 for shear

The total jet impingement load seen by the wall is:

$F_T = C_D F_J$

where:

C_D = dynamic load factor = 2.0 for suddenly applied load

If R is greater than or equal to F_T, there will be no punch shear failure.

Curves relating dimensionless wall thickness ($X = W/D_P$) and dimensionless distance ($Y = L/D_P$) are shown in Figures 14B-7 and 14B-8 for steam and water lines, respectively. The specified concrete compressive strength, f'_c, is assumed to be 3000 psi.

These curves are extremely conservative. A more realistic analysis to determine the effective jet impingement force requires additional parameters, such as pipe lengths from sources, elbows, and flow restrictors and fluid characteristics. A conservative approach was used in the analysis for this appendix.

14B.2.3.2.4 Fluid Jets and Interaction With Steel Plates

For a fluid jet issuing from a crack (one-half the pipe diameter times one-half the pipe thickness) in a pipe wall, the magnitude of the jet force is small because the break area is small. It can be shown that either a 1-foot reinforced-concrete wall or a 1/8-inch steel plate being hit by a jet from close distance from a crack in a 32-inch, 2300-psi water line will not experience a local failure by punch shear. Therefore, it is not necessary to analyze the local punch shear failure of concrete walls or steel plates due to fluid jets from cracks in pipe walls.

14B.2.3.2.5 Fluid Jet Range

Any safety-related structure, piping component, and equipment located in the fluid jet traveling path is considered susceptible to jet impingement. As the jet propagates away from the pipe break area, it expands at a diverging angle. Therefore, the jet intensity decreases with distance from the break location to the target, whereas the total jet force is assumed to remain constant.

14B.2.3.3 **Pressure and Environment**

The pressure buildup from the postulated break of a high-energy pipe in a compartment or building is calculated using the computer program CUPAT (Reference 7).

14B.2.3.3.1 Introduction

CUPAT is a computer program used to calculate pressure and temperature transients in various nuclear power plant compartments resulting from a postulated high-energy pipe break.

The output is used mainly for design purposes in establishing the peak pressure differentials across the compartment walls.

This program was derived from the LOCTIC computer program (Reference 8) which was used to calculate pressure and temperature transients for the primary containment. Chapter 5 discusses the current method for primary containment analysis. There are two major differences between LOCTIC and CUPAT:

1. LOCTIC includes the effects of heat transfer by providing subroutines to handle sources and sinks. CUPAT assumes a volume that receives heat and mass from a broken piping source and discharges heat and mass to its surroundings, but aside from that there are no other heat sources or sinks (adiabatic assumption).
2. CUPAT allows for flow out of the volume considered as well as flow in. There is no provision in LOCTIC for mass outflow from the containment volume.

In order to calculate the transients within a compartment, CUPAT numerically solves finite difference equations defining heat and mass flows into and out of the compartment. The program uses the same basic assumptions as those used in LOCTIC, namely:

1. Mass and energy added or removed during each small time step are based on rates determined at the start of the time step; i.e., during any time interval, the thermodynamic state is assumed to be steady and the response of the flow out of the volume to changes in the thermodynamic state is instantaneous (quasi-steady-state assumption).
2. The atmosphere in the compartment mixes instantaneously and homogeneously, i.e., at each point in time, the atmosphere is in a state of thermodynamic equilibrium.

A detailed description of the approach to the problem is presented below.

The calculational approach used in CUPAT is summarized in the block diagram shown in Figure 14B-9. Blocks (1) through (5) in the figure are traversed once for each time step.

14B.2.3.3.2 Calculational Approach

14B.2.3.3.2.1 *Quasi-Steady-State Assumption.* The problem of analyzing the transient effects of a LOCA is very complex. The thermodynamic state of the compartment atmosphere is continuously changing. This state depends on the mass and energy flows into and out of the compartment. The flows, in turn, are dependent on the thermodynamic state within the compartment. In order to solve such a problem numerically, some simplifying assumptions must be made.

First, the system is defined as the compartment atmosphere at any given time. This includes any air, steam, and water droplets present, but not the walls, equipment, or internal structure of the compartment itself. If the time step is small enough, the net rate of mass and energy addition to the system will not vary appreciably during the time step. Thus, the flow rates are calculated assuming that the thermodynamic state does not change during the time step, and this assumption eliminates the need to iterate and converge on the inflow and outflow for each time step. This approach was used in LOCTIC (which also includes heat flows) for the primary containment transients, and is also used in CUPAT.

14B.2.3.3.2.2 *Mass and Energy Flow Rates into Compartment.* The mass and energy flow rates into the compartment are supplied as input to the program in tabulated form. These blowdown rates into the compartment may be obtained from the output of a LOCTIC or LOCTVS (Reference 9) computer run or from the assumption of Moody flow (Reference 10) with a known pressure blowdown.

The flow of fluid from a piping break is relatively insensitive to the back pressure in the compartment, since the pressure in the high-energy line is above 275 psig. Thus, the mass and energy inflow data specified as input are close to the actual flow, but are conservatively high.

14B.2.3.3.2.3 *Calculation of the Thermodynamic State of the Compartment.* In each time step of the numerical calculation, equilibrium temperature and pressure in the compartment are determined based on new values of mass and internal energy. Properties of water are obtained from the steam tables. The detailed procedure by which the pressure and temperature of the compartment atmosphere are found from the updated values of mass and internal energy is described below.

Initially the equilibrium state is considered to be a two-phase mixture of air, saturated steam, and saturated liquid. However, if the energy content for the given mass is greater than that required for saturation, a single-phase mixture of air and superheated steam is determined.

To arrive at the correct equilibrium conditions, a curve of internal energy of the air, steam, and liquid in the volume versus temperature is generated. The basis for the curve is that the mass of water present in the compartment is at a saturated equilibrium state for each temperature, and the total internal energy of the system at this temperature is calculated accordingly. The actual total internal energy is then used to enter this curve and find the true temperature. The total pressure is then determined by adding the vapor pressure to the air partial pressure, which is calculated by the ideal gas flow at this temperature.

In the case where the contents form a superheated vapor, the superheat section of the steam tables is used to match the specific volume of the steam and the internal energy to find the equilibrium temperature and pressure.

14B.2.3.3.2.4 *Calculation of Flow Rate Out of Compartment.* The CUPAT computer program uses the LOCTVS vent flow (Reference 11) to determine the flow rate out of the compartment. A homogeneous flow model is used in LOCTVS to calculate flow out of the drywell through the vents of a pressure suppression containment. Although flow through the vents is characterized by slip between the gaseous and liquid phases, a homogeneous model yields lower flow rates and is used for conservatism. The ability of the vent flow model to conservatively predict flow through the vents has been checked against the Bodega and Humboldt Bay pressure suppression tests.

14B.2.4 Protection Against Pipe Whip

A combination of three basic approaches was used for the protection of targets from whipping pipes. These approaches include:

1. Separation of redundant features by distance or location so that at least one feature remains intact.
2. The incorporation of many redundant features into the design of the safety-related systems for assurance of reliability.
3. For the largest main steam and feedwater lines, an extensive inspection program was devised for each postulated break point. By means of ultrasonic and/or radiographic testing in addition to a visual surveillance program, defect propagation can be detected at any early stage and repaired accordingly, thereby ensuring the integrity of each postulated break point.

14B.2.5 Analysis of Seismic Category I Structures

Analysis of Seismic Category I structures for loads other than pipe break in the main steam valve house is given in Section 15.2.

14B.3 HIGH-ENERGY SYSTEMS

14B.3.1 System Identification

The following systems contain high-energy lines, as defined in Section 14B.2:

1. Main steam.
2. Feedwater.
3. High-pressure heater drains and vents.
4. Moisture separator drains.
5. Auxiliary steam.
6. Condensate.
7. Low-pressure heater drains and vents.
8. Boron recovery.
9. Liquid waste.
10. Chemical volume and control.
11. Safety injection.
12. Steam generator blowdown.
13. Extraction steam.

14. Sample.

The high-energy lines in these systems were reviewed in conjunction with safety-related and safe-shutdown equipment (Table 15.2-1) by means of a detailed drawing review and onsite inspection. Those portions of the high-energy lines in proximity to the safety-related and safe-shutdown equipment have been identified. These portions of the high-energy lines are defined as sources and are presented in Table 14B-2.

The safety-related equipment and plant shutdown equipment in proximity to these sources (identified as targets) are listed in Section 14B.4.1.

Table 14B-2 presents a listing of the high-energy line sources with their maximum operating conditions, locations, and seismic classifications. These lines were individually analyzed for adverse effects on targets. Sources such as smaller lines located in the target areas were not individually analyzed, since the sources listed were the worst cases for their respective areas.

14B.3.2 Quality Assurance and Inspection

Piping presently installed was designed and fabricated in accordance with the criteria described in Section 1.4, *Compliance with Criteria*.

14B.3.3 Detection of Failures

As described in Section 7.2 and delineated in Table 7.2-1, reliable and redundant systems have been incorporated into the present plant design for detection of failures in the main steam and feedwater systems.

As described in Section 11.3.4, the area radiation monitoring system is designed to alarm when radiation levels in their associated areas are slightly above background. This system detects pipe failures in systems containing radioactive fluids.

Detection for breaks in lines routed through the Auxiliary Building is discussed in Section 14B.5.3.3.

14B.4 PLANT SHUTDOWN AND SAFETY-RELATED EQUIPMENT

14B.4.1 Introduction

Table 14B-3 lists the systems and major equipment locations that constitute postulated targets among the plant shutdown and safety-related equipment. Associated cables and controls are considered along with this equipment.

14B.4.2 Emergency Procedures

Main steam or feedwater breaks outside the containment are discussed in Section 14B.6. Subsequent to a main steam or feedwater break, assuming offsite power is unavailable, plant shutdown is achieved by actuation of the emergency core cooling system and removal of core decay and sensible heat via steam release through the steam generator power operated relief valves, and maintenance of steam generator water inventories by means of the auxiliary feedwater system.

Section 9.3 details the operation of the residual heat removal system necessary for long-term cooling and cold shutdown of the reactor.

Shutdown equipment is normally controlled from the control room. However, in the event that evacuation of the control room is necessary, shutdown equipment can be controlled from an auxiliary shutdown panel.

Emergency procedures direct the operators to perform mitigating actions in the event of a high-energy line break outside containment. The operator response to a break in the main steam valve house is described in Section 14B.6.

14B.4.3 Relationship of High-Energy Lines to Safe-Shutdown and Safety-Related Equipment

Figures 14B-10 through 14B-17 show the high-energy systems and the safe-shutdown and safety-related equipment.

14B.5 EFFECTS OF PIPE BREAKS AND CRACKS

14B.5.1 Main Steam

14B.5.1.1 Break Locations

Break locations were postulated in the main steam lines from the containment to the turbine building in accordance with Section 14B.2.2. For the main steam line, 0.8 of the allowable thermal stress is 22,500 psi, and 0.8 of the allowable combined primary and secondary stress is 0.8 $(S_A + S_h)$ = 37,500 psi. Since 0.8 of the allowable stresses was not exceeded, the two intermediate locations between terminal points were selected on the basis of maximum primary-plus-secondary stress. Piping downstream of the manifold common to the three steam lines was not analyzed seismically. For this piping, pipe breaks were assumed; however, because of separation, no further analysis is required. At all break points, both circumferential and longitudinal breaks were postulated to occur.

The break points are listed in Table 14B-4 along with the thermal and combined stress levels. The break locations are shown on Figure 14B-10.

Cracks were selected in the vicinity of all targets.

14B.5.1.2 **Separation**

The steam lines in the turbine building were analyzed, and satisfactory separation was found to exist between steam lines and any safety-related features.

The control room and emergency diesel-generator rooms are separated by sufficient distance from all high-energy lines, so that whipping pipes or steam jets will not adversely affect their respective functions. These conclusions were based on results given in Section 14B.2.3.

The auxiliary feedwater modification described in Section 14B.5.1.7 provides a system widely separated from postulated breaks.

14B.5.1.3 **Pipe Whip**

An extensive nondestructive testing program, as described in Section 14B.5.1.6, is used to preclude breaks, thereby making pipe whip a noncredible incident.

Since the guideline referenced in Section 14B.1.1 requires a postulated failure, each postulated main steam line break has been evaluated for the effects of pipe whip. Because feedwater supply to the steam generators is the ultimate requirement for a safe shutdown, the evaluation was based on maintaining the feedwater function. The results of this investigation are shown in Table 14B-5. These results were based on the plastic hinge lengths established in Section 14B.2.3.1 and on discussions with the turbine-driven auxiliary feedwater pump manufacturer indicating that the pump can operate in a steam environment.

Since loss of offsite power must be assumed, and the turbine drives are not environmentally qualified by tests, additional assurance that feedwater will be maintained is obtained by the auxiliary feed cross-connect system. As shown in Table 14B-5, there are no effects on the auxiliary feed cross-connect system, considering all postulated breaks. The auxiliary feed cross connect was a modification to the initial plant design and is discussed in Section 14B.5.1.7.

14B.5.1.4 **Fluid Jet Effects**

Jet impingement loadings on the walls, valves, and pipes inside the main steam valve house have been calculated. The time-history results of jet force from a pipe break at the most adverse location in the steam line within the valve house is calculated as follows (Section 14B.2.3.2):

$F(t) = 1.0\ P_oA$ for $t \leq 0.020$ sec

$F(t) = 0.7\ P_oA$ for $0.020\ \text{sec} < t \leq 0.113$

$F(t) = 0.19\ P_oA$ for $t > 0.113$ sec

The initial jet force on the walls was calculated as:

$F_o = K\ P_o\ A$

where:

K = initial thrust coefficient = 1.0

P_o = hot standby pressure = 1005 psig

A = flow area = 616 in^2

F = 619 kips

For the longitudinal breaks, the break size was taken as 60 x 10.3 inches with the jet diverging at a 20-degree inclusive angle. The impingement areas, jet pressures, and loads corresponding to each of the postulated breaks are indicated in Table 14B-6.

Local damage to the walls and floors was checked based on Section 14B.2.3.2. The conservative calculation, which assumes a dynamic factor of two and no energy loss, indicates that the floor at Elevation 27 ft. 6 in. is subject to some local damage from jet impingement. However, the containment, the walls, and the roof withstand the effects of jet impingement with no punch shear damage.

For breaks of the main steam lines, jet impingement loads on the valves were calculated. The maximum normal force on the valves is given by:

$F_v = C\ P_t\ A_t \cos^2 \alpha/1000$ (kips)

where:

C = shape factor for flow around the valve, cylinder, C = 0.6

P_t = initial jet pressure at the target (psi)

A_t = impingement area (in^2)

α = incident angle

The maximum normal jet forces on the valves are listed in Table 14B-7. It should be noted that these loads drop instantaneously to a fraction of the levels recorded. Available calculations indicate that the nonreturn valve will continue to function as a check valve, preventing blowdown of the undamaged loops. Calculations indicate that jet impingement will not break a main steam trip valve housing, but can cause the valve to fail open. However, with the nonreturn valve operable, a broken line could still be isolated, so that only one steam generator would blow down.

14B.5.1.5 Pressure and Environment

The main steam valve house and the reactor trip switchgear room, as shown in Figure 14B-10, are the only target areas that can be affected by steam following a postulated break or a crack in a main steam line, as discussed in the following sections.

As shown on Figure 14B-10, the reactor trip switchgear room is far removed from the source lines; therefore, the probability of having a steam environment within the room is extremely remote.

With the existence of the nondestructive testing program, as described in Section 14B.5.1.6, only smaller steam-line breaks need to be considered for pressure effects on the main steam valve house. The pressure buildup within the valve house, following a smaller steam-line break, is negligible.

In order to comply with the criteria, as referenced in Section 14B.1.1, the pressure in the main steam valve house has been calculated for the largest steam-line break. Frictionless Moody flow and the CUPAT computer program, as described in Section 14B.2.3.3, were used in these calculations. The results are shown in Figure 14B-18.

The main steam valve house contains many targets, as shown in Table 14B-3. As detailed below, all the targets either fail in the safe position or operate mechanically:

1. Targets that fail in the safe position.
   a. Main steam trip valves (close).
   b. Auxiliary feed pump steam isolation valve (open).
2. Targets that operate mechanically.
   a. Feedwater isolation check valves.
   b. Main steam nonreturn valves.
   c. Main steam safety valves.
   d. Turbine driver for auxiliary feed pump.

Furthermore, all electrical cables considered as targets are the same as the cables used inside the containment. Since this cable has been qualified by test for post-design-basis-accident conditions inside the containment, the cabling is not subject to common mode environmental failure.

The blowdown rates used to obtain the above results were based on blowdown of one steam generator, following the postulated steam-line break. The blowdown of only one steam generator can be justified by taking no credit for the main steam trip valves, but taking credit for the nonreturn valve (NRV-201A, B, C for Unit 2) in the affected steam line. Credit for the nonreturn valve is justified as follows:

1. As described in Section 14B.5.1.4, jet impingement will not affect the intended performance of this valve.
2. There is no instrumentation or electrical component required for operation of the valves. The nonreturn valves require only reverse steam flow for their intended operation.

3. In the worst case, where blowdown is the greatest following the postulated steam-line break, the steam system is in the hot standby condition. Blowdown is greatest for this case, since the steam-line pressures are at a maximum. In this condition, there is little or no steam flow to hold the valve disk in an open position; therefore, the valve is performing its required function even before the postulated failure. In all cases, when the system pressure is high, with respect to the pressure at 100% power, the flow rates are low and the valve is in a nearly closed position before the postulated incident occurs.

14B.5.1.6 **Inspection Program for Large Steam Lines**

An extensive nondestructive testing program is provided for the main steam postulated break points in the main steam valve house. These points, a total of 12 for each unit, are shown in Figure 14B-10.

14B.5.1.6.1 Procedures

A program of periodic examination exceeding the requirements of ASME Section XI, Winter Addenda 1972, as instituted by Regulatory Guide 1.51, was originally provided as follows:

1. A baseline examination was performed including 100% coverage of all subject points.
2. Inservice examinations were performed including 100% coverage of all subject points for the initial 3 years of the 10-year inspection interval as defined by ASME Section XI.
3. Examinations were performed including 100% coverage of all subject points for two subsequent inservice examinations.

Currently, the Augmented Inspection Program includes periodic examinations that meet the requirements of the Technical Specifications and the Technical Requirements Manual. This program requires ultrasonic and surface examinations to be performed on 1/3 of the welds every 40 months, with a cumulative 100% coverage of all welds by the end of the interval. Repairs are made as required. Upon completion of any repairs, the program, as described above, will be reinstated for the repaired postulated break point.

In addition to the above testing program, a visual inspection of the surface of the insulation at the main steam break point locations in question is performed weekly for detection of leaks. If a leak is detected, it is immediately investigated and subsequently repaired if the leakage is caused by a through-wall crack. The investigation allows for evaluation of system functionality to determine if continued plant operation can or cannot be justified, with consideration of the ASME Section XI Code for applicable Class piping, prior to the repair.

14B.5.1.6.2 Methods

The ultrasonic test procedures include the examination of the postulated break points and heat-affected zones. Consideration of weld thickness, geometry, material, and curvature parameters results in establishing the appropriate transducer sizes, optimum beam angles, and frequencies for test reliability and repeatability. Where appropriate, additional techniques are used for evaluating reflectors and obtaining characterization data. Test sensitivity is in accordance with ASME Section XI, which defines reference calibration requirements.

14B.5.1.6.3 Basis for the Inspection Program

As shown in a PVRC report (Reference 12), and a Virginia Power Technical Report (Reference 15), toughness of nuclear power plant piping materials is high enough to prevent brittle fracture at operating conditions. This conclusion can be supported by fracture mechanics calculations.

Furthermore, from the following fracture mechanics techniques and calculations, the critical size of surface and internal flaws far exceeds the thickness of the piping material. Consequently, a surface or an internal flaw will extend through the wall thickness and form a subcritical through-wall crack, which will leak before it reaches its critical size.

The main steam line material is SA155, grade CMS 75, Class 1, outside diameter 30 inches, wall thickness 1 inch. Plate material for piping is SA299. Fittings were fabricated from ASTM A299 steel plate stock, using the ASTM A234 Grade WPB specification. Fitting material equivalent to ASTM A691, Grade CMS 75, Class 32: carbon-manganese-silicon alloy steel can be used as replacement material for the main steam line pipe and fittings.

Feedwater line material is ASTM A106 Grade B: Carbon steel. Fittings are ASTM A234 WPB. ASTM A335 Grade P11 or P22: Chromium-Molybdenum steel can be used as replacement material for feedwater seamless pipe. ASTM A234 WP11 or WP22 can be used a replacement material for fittings.

For both main steam and feedwater piping, the ASME SA equivalent materials can be used as a preferred substitute for ASTM materials.

14B.5.1.6.4 Fracture Mechanics

The application of fracture mechanics techniques allows prediction of the critical flaw size that can cause fast or unstable fracture in a stressed structure.

When the critical flaw size is established for a nominal stress level, it is possible to decide the acceptable defect size. One of the criteria is the leak-before-fracture criterion, which requires that the defect wall propagate slowly through the wall of the pipe and that the pipe will leak before the crack is large enough to trigger the fast fracture.

Fabricated structures usually contain several types of defects, including surface flaws, internal flaws, and through-the-thickness cracks. The critical flaw size will be calculated for each of these flaws using fracture mechanics relationships. These formulas were used in two recently published papers (References 12 & 13) treating similar problems. As emphasized in the PVRC Recommendations on Toughness Requirements for Ferritic Materials (Reference 12), the pipe wall section is usually not thick enough to support plane strain fracture propagation, which can be properly analyzed by the fracture mechanics methods. In other words, the load limits and critical flaw size calculated using fracture mechanics will in general be more conservative for pipe than for the thick section structures where the plane stress conditions can exist. Fracture will occur when the value of the stress intensity factor K_I reaches the critical value K_{IC}. The critical flaw size is related to the K_{IC} in several different formulas depending on geometry of structures, flaws, shape, and environmental factors. In this work, the following assumptions were made about factors affecting the relation between the K_{IC} and the critical flaw size:

1. Material properties (toughness and strength) of the weld metal and the heat-affected zone in the longitudinal and circumferential weldments are the same as in the base material.

2. The lowest and the highest temperatures in the main steam line are 510°F and 547°F. The lowest and the highest temperatures in the feedwater line are 438°F and 450°F. However, only the lowest temperatures are used in calculations of fracture toughness because they give more conservative values for critical crack size.

3. Because of uncertainty involved in evaluating the possible stress state, Irwin's (Reference 14) suggestion was accepted that the membrane stress is equal to the yield strength. For SA106B pipes, Class 1 data are given in Section III. For SA155 (plate SA299) material, the elevated temperature yield strength was not given in Section III, Class 2, and the allowable design stress data for Class 1 were used to get the yield stress.

4. The stress intensity factor of 300,000 psi $\sqrt{\text{in.}}$ was used (Reference 13) for SA106B pipe. In this work, a lower value of 200,000 psi $\sqrt{\text{in.}}$ was accepted, which would correspond to the reference stress intensity factor K_{IR} at the temperature NDT + 180°F. The lowest temperature for SA106B pipe is 438°F, and for SA155 pipe, 510°F, which means that the NDT temperature in the first case would be 438–180 = 258°F, and in the second case, 510–180 = 330°F. This is of course a very conservative assumption, because the NDT temperature for these materials is below room temperature.

Toughness of replacement materials is documented in Reference 15. This reference provides technical justification for use of replacement materials based upon fracture toughness of materials. The replacement materials are assessed using linear-elastic fracture mechanics, elastic-plastic fracture mechanics, and limit load methods.

14B.5.1.6.4.1 *Internal Flaw.* The internal flaw is an ellipsoid, as shown in Figure 14B-19, Part A. The flaw is located in the center of the pipe wall. The flaw can be axial (major axis parallel to the pipe axis) or circumferential (major axis perpendicular to the pipe axis). A further assumption is that the flaw is small compared to the pipe radius. Thus the curvature effect can be neglected and the pipe can be approximated with an infinite plate under uniform applied stress. The stress intensity factor K_I for this model is given (Reference 13) as:

where:

σ = applied stress

$$K_I = \left[\sin^2\beta + \frac{a^2}{b^2}\cos^2\beta\right]^{1/2} \frac{\sigma(\pi a)^{1/2}}{\phi}$$

β = angle at which the stress intensity is calculated

ø = the following elliptical integral:

$$ø = \int_o^{\pi/2}\left[1 - \frac{b^2 - a^2}{b^2}\sin^2\theta\right]^{1/2} d\theta$$

At the tip of the major axis $\beta = 0$, while at the tip of the minor axis, $\beta = \frac{\pi}{2}$.

If it is assumed that the major axis of the ellipsoid is twice as long as the minor axis, the equation for K_I becomes:

$K_{IC} = 0.826\ \sigma\ (\pi a_{cr})^{1/2}$

It has been shown that, for an elongated crack (b>>a), the critical stress intensity factor is given by:

$K_{IC} = 1.2\ \sigma\ (\pi a_{cr})^{1/2}$

Substituting the values for the stress intensity factor and applied stress (yield strength at the temperature) in the first equation for K_{IC} results in the following:

Material	Temperature °F	2 a_{cr}(Critical Flaw Size), in.
SA106B	400	42.0
SA155	500	46.5

Substituting the values for the stress intensity factor and applied stress in the second equation for K_{IC} results in the following:

Material	Temperature °F	2 a_{cr}(Critical Flaw Size), in.
SA106B	400	19.6
SA155	500	22.8

As can be seen, all critical flaw size values are much greater than the wall thickness, which means that the flaws would extend through the wall without becoming critical. In other words, the internal flaw will become a through-the-thickness crack and will leak.

14B.5.1.6.4.2 *Surface Flaw.* The surface flaw is a semi-ellipsoid, as shown in Figure 14B-19, Part B. The flaw can be axial or circumferential, as in the previous case. Again the curvature effect is neglected, and the stress intensity factor is given (Reference 13) as:

$$K_{IC} = 1.12\sigma\,(\pi a_{cr})^{1/2}$$

Material	Temperature °F	a_{cr}(Critical Flaw Size), in.
SA106B	400	11.3
SA155	500	13.2

As in the case of the internal flaw, the surface flaw will penetrate the pipe wall without becoming critical.

14B.5.1.6.4.3 *Axial Through-Wall Crack.* The simplest formula for axial through-wall cracks is obtained when the pipe is assumed to be infinite plate; that is, the diameter is much greater than the thickness. The critical crack size for such a simple case is (Reference 12):

$$\underline{K}_{IC} = \sigma\,(\pi b_{cr})^{1/2}$$

where 2 b_{cr} is the critical crack length. The geometry is shown in Figure 14B-19, Part C. When the pipe diameter decreases, corrections are necessary. As a result of tests at Battelle Memorial Institute on SA106B piping, the critical size of the axial through-wall crack is given (Reference 13) as:

$$b_{cr} = \left\{ \frac{Rt}{1.61}\left[\left(\frac{\sigma^*}{\sigma}\right) -1\right] \right\}^{1/2}$$

where:

b_{cr} = critical half-length

σ^* = flaw stress

R = average pipe radius

t = thickness

Material	Temperature °F	Equation	2 b_{cr} (Critical Flaw Size), in.
SA106B	400	K_{IC}	28.4
SA106B	400	b_{cr}	5.5 (14-inch o.d. Schedule 80)
SA106B	400	b_{cr}	7.5 (18-inch o.d. Schedule 100)
SA155	500	K_{IC}	33.2

Material	Temperature °F	Equation	$2\ b_{cr}$ (Critical Flaw Size), in.
SA155	500	b_{cr}	9.5

Flow stress data were not available for SA155 piping. The strength of this material is higher than the strength of SA106B steel. Consequently its flow stress must be greater than the flow stress of SA106B steel. To calculate b_{cr}, the flow stress value used was based on the ratio of ultimate tensile strength of SA106B material to SA155 material.

14B.5.1.6.4.4 *Circumferential Through-Wall Crack.* It is shown (Reference 13) that the critical length of a circumferential through-wall crack is greater than the critical length of an axial crack.

14B.5.1.6.4.5 *Flaw Growth.* Under the influence of cyclic loads, small defects can grow to critical size. It has been shown that an empirical expression accurately describes the flaw growth:

$$\frac{da}{dn} = C\ (\Delta K)^m$$

where $\frac{da}{dn}$ is the flaw growth rate, ΔK is the change in stress intensity factor per cycle; C and m are constants.

The following calculation (Reference 13) describes the growth of the code allowable internal and surface flaws into through-wall cracks. Since the size of these flaws is small, pipe curvature can be neglected and there is no difference between axial and circumferential flaws. Surface defects in Seismic Category I piping allowed by the code are defects with a maximum depth of 5% of the wall thickness (t). Therefore the maximum flaw depth will be 0.05t. The material constants have values of $C = 1.6 \times 10^{-4}\ in^{-1}$ and $m = 4$ (at 550°F). Note that the value of the exponent m is conservative. The exponent varies between 2 and 4 for different steels and, using its maximum value, the growth rate will be the fastest.

Integration of the previous equation gives the number of cycles:

$$n = \int_{a_i}^{a_f} \frac{da}{C(\Delta K)^4}$$

where $a_i = 0.05$ t is the initial flaw depth (the code allowable defect) and a_f is the final flaw depth. For a surface flaw, the integral becomes:

$$n = \frac{1}{C} \int_{a_i}^{a_f} \frac{da}{[1.12\sigma(\pi a)^{1/2}]^4}$$

If a_f = thickness, then n is the number of cycles to develop a through-wall crack. When the equation for n is applied to SA155 pipe, $a_i = 0.05 \text{ x } 1 = 0.05$ in. and $a_f = 1$ in. σ = yield stress at 550°F (the flaw growth will be faster at higher temperatures).

$$n = 4.13 \times 10^9 \times \frac{1}{(27.7)^4} \left(\frac{1}{0.05} - 1\right) = 132,000 \text{ cycles}$$

The additional growth of this defect to reach critical size is not important because the pipe will leak and the leak will be repaired.

It has been shown that the growth of an internal flaw is even slower than in the above case (Reference 13). The number of cycles during the lifetime of a nuclear power plant can be obtained taking into account daily and weekly power reductions, start-ups, shutdowns, and other changes in pressure. An estimate (Reference 13) gives the number of cycles at about 13,000, which is much smaller than the value for the formation of a through-wall crack. For subsequent license renewal, the allowable number of cycles has been determined to be 70,390 based on the application of the updated stress intensity factor solutions from API-579 and fatigue crack growth from ASME Section XI.

14B.5.1.7 **Modifications**

The following modifications to the initial plant design were made to further ensure safe-shutdown reliability and the operation of plant protective features:

1. The pump discharge piping of the auxiliary feedwater systems in Units 1 and 2 were cross connected so that the unaffected system will have the capability of maintaining both units in a shutdown condition. Furthermore, an additional source of makeup water for the auxiliary feedwater systems was installed. An in-ground 100,000-gallon emergency condensate makeup tank and two booster pumps can supply the suction of the unaffected auxiliary feedwater pumps. These modifications were designed and installed in accordance with ANSI B31.1-1967, Seismic Category I criteria, and are also tornado-protected. These modifications are shown in Figure 14B-20.

   As described in Section 14B.6 one auxiliary feedwater pump is required to remove stored and residual heat. Therefore, no redundancy requirements were lost for either unit since each unit is equipped with two motor driven auxiliary feedwater pumps (350 gpm nominal flow rating) and one turbine driven auxiliary feedwater pump (700 gpm nominal flow rate).

   Since, with the modifications, the unaffected auxiliary feedwater system can be required to supply both units, the residual heat removal capacity from the original 110,000-gallon emergency condensate storage tank is halved. Another reliable source of water is the fire protection system main, which has the capability of supplying 500,000 gallon of water to the suction side of the unaffected auxiliary feedwater pumps. In addition, the 300,000-gallon condensate storage tank used for normal condensate makeup can be used to supply the 110,000-gallon emergency condensate storage tank utilizing gravity flow. The 100,000-gallon emergency condensate makeup tank was added to enhance the reliability of the modified system.

2. The turbine drivers for the containment spray pumps were disconnected from their steam supply lines and the three-inch lines were removed from the containment spray pump room. These modifications eliminated the containment spray pumps as a target.

   Since the turbines were used only as redundant pump drivers for the two full-size containment spray pumps, the pumps with their motor drivers still maintain the redundancy requirements of the containment spray system.

3. In response to an Atomic Energy Commission (AEC) inquiry concerning the ability to shut down the reactor following the postulated loss of the main steam valve house (MSVH), Virginia Power committed to a SI system modification (Reference 16). The AEC's inquiry was made during the original review of FSAR Appendix D (currently Figure 14B). The modification installed a SI system piping cross-connect between the Unit #1 and Unit #2 RWSTs and associated valves and controls (refer to Section 6.2.2.1.4). The modification ensures a supply of RWST water to each unit's SI charging pumps in the event the normal supply line is rendered inoperable due to the postulated loss of the associated main steam valve house. It should be noted that charging pump suction piping from the RWST was not identified as a potential target for a high energy line break (HELB) in the MSVH.

14B.5.2 Feedwater

14B.5.2.1 **Break Locations**

Break locations were postulated in the feedwater lines from the containment to the feedwater pumps in the turbine room in accordance with Section 14B.2.2. For the feedwater lines, 0.8 of the allowable thermal stress was 18,000 psi. For each line considered, none of the calculated thermal stresses exceeded 0.8 of their allowables. Piping upstream of the containment was not analyzed seismically, so that intermediate points were selected on the basis of maximum thermal stress. For piping from the containment to the turbine building, two intermediate locations were selected. Breaks were assumed for piping in the turbine building; however, because of physical separation, no detailed analysis was required. At all break points, both circumferential and longitudinal breaks were considered.

The break points are listed in Table 14B-8 along with thermal stress levels, as calculated. The break locations are shown in Figure 14B-10.

Cracks were selected at all locations in the vicinity of targets.

The environmental impact on the adjacent EQ rooms resulting from the worst case turbine building high energy line break (HELB) have been determined. The temperatures in these rooms were calculated as a function of EQ barrier breach size. These rooms include the control room envelope, MER-5, and the emergency diesel generator rooms. The size of these breaches into the above rooms is limited based on the average internal room temperature of 120°F (see Section 7.7.1).

14B.5.2.2 **Separation**

The same degree of separation provided between targets and a postulated steam-line break is found for the postulated feedwater line break.

14B.5.2.3 **Pipe Whip and Fluid Jet Effects**

The effects of pipe whip and fluid jets from a postulated feedwater line break are similar but less severe than a main steam line break.

Table 14B-9 contains the results of the evaluation for maintaining the feedwater system functional. All the assumptions required for the main steam system as described in Section 14B.5.1.3 also apply to the feedwater system.

14B.5.2.4 **Pressure and Environment**

The main steam valve house will withstand the pressure buildup from a postulated feedwater line break, which is less than the steam-line break pressure buildup. Environmental effects are similar to the main steam line break but less severe.

14B.5.2.5 **Inspection Program for Larger Lines**

An extensive nondestructive testing program was initiated for the main feedwater postulated break points in the main steam valve house. These points, a total of eight for each unit, are shown in Figure 14B-10.

14B.5.3 Other High-Energy Lines That Maintain Maximum Operating Temperatures Greater Than 200°F and Maximum Operating Pressures Greater Than 275 psig

14B.5.3.1 **Break Locations**

Figures 14B-11, 14B-12, and 14B-13 show the break locations that were postulated for circumferential and longitudinal breaks. Postulated break locations were selected in accordance with the criteria specified in Section 14B.2.2. Tables 14B-10 and 14B-11 list the stresses in the piping systems at the postulated break locations. Designated numbers for these high-energy lines are:

1. Steam Generator Blowdown

Unit 1	Unit 2
3"-WGCB-1-601	3"-WGCB-101-601
3"-WGCB-2-601	3"-WGCB-102-601
3"-WGCB-3-601	3"-WGCB-103-601

2. Letdown from Regenerative Heat Exchanger

Unit 1	Unit 2
2"-CH-6-602	2"-CH-306-602

Cracks were postulated throughout the length of the lines for any adverse effects on targets. For computation of crack size, the diameter and wall thickness of these pipes are given in Table 14B-2.

14B.5.3.2 **Pipe Whip and Fluid Jet Effects**

The letdown line and the steam generator blowdown lines will be permitted to whip in the event of a postulated circumferential break. It has been determined by an extensive drawing review, onsite inspection, and pipe break analysis sheets that no additional restraints are required in order to meet the criteria for pipe breaks. An example of the pipe break analysis sheets for these lines is given in Table 14B-12. Target protection is maintained in the following manner:

1. By means of physical separation, including distance, building support columns, concrete walls, and larger sized pipes, and/or
2. By means of the many redundant features originally designed into the existing systems.

In all cases, the postulated pipe break will not jeopardize a safe plant shutdown.

14B.5.3.3 **Pressure and Environment**

For the high energy line break analysis, the flow from the broken letdown line was 60 gpm with an operating temperature of 287°F and a pressure of 289 psig; therefore only local effects were considered. Although the actual letdown flow and pressure may be higher than these values, the conclusions of the analysis remain bounding.

The limiting case for pressure buildup and auxiliary building environmental conditions is the break of a 3-inch steam generator blowdown line. The maximum flow rate through this line is 140 lb/sec at a maximum operating temperature of 515°F and pressure of 775 psig. Calculations were made considering the area in which the blowdown lines are located as the worst case. This area is shown in Figure 14B-11 and extends to the charging pump cubicle walls as shown in Figure 14B-12. Because of the large volume and the large vent areas, there will be negligible pressure buildup within this volume, but the temperature in this area can essentially reach 212°F if blowdown is not stopped. Therefore, temperature sensors are provided in various areas of the Auxiliary Building to provide individual temperature indication and an alarm in the main control room to alert the operators to a potential problem.

An excess flow-measuring device mitigates the consequences of a steam generator blowdown line break outside the containment. This device is located upstream of the inside containment isolation valve. If blowdown line flow exceeds a predetermined value, a signal will close the inside containment isolation valve for that blowdown line. Automatic isolation of the steam generator blowdown lines is accomplished within 30 seconds in the event of a piping break. Also, manual isolation associated with other breaks or cracks must be made within 15 minutes to meet the environmental qualification requirements of certain Class 1E components in the Auxiliary Building.

Also, excess flow is annunciated in the control room. Indication of isolation valve closure presently exists in the control room.

Detection and subsequent isolation of the affected line will inhibit the increase of temperature and humidity of the environment in the areas adjacent to postulated cracks or breaks.

14B.5.4 High-Energy Lines That Maintain a Maximum Operating Temperature of Greater Than 200°F or a Maximum Operating Pressure of Greater Than 275 psig

14B.5.4.1 Break Locations

Figures 14B-11 through 14B-15 show the locations of the high-energy lines in question. In addition, Table 14B-2 gives the maximum operating conditions of each of the lines shown. Cracks were postulated throughout the entire length of each line shown, and evaluated for any adverse effects on targets. The diameter and thickness of these pipes are given in Table 14B-2 for computation of crack size.

14B.5.4.2 Separation

Source lines not located within the confines of the areas shown in Figures 14B-10 through 14B-15 have no adverse effects on targets because of the physical separation provided by the building arrangement. For this reason, high-energy lines outside these areas were not considered as sources.

14B.5.4.3 Local Environmental Effects and Jet Impingement

In many cases, shutdown and other protective features are far enough removed from the lines in question that local effects of a postulated crack will have no effect on even the redundant features.

In other cases, target protection is maintained with the many redundant features designed into the present systems and the separation of these by means of distance, walls, and location. An example of one of the pipe break/mini-crack analysis sheets is shown in Table 14B-13.

Except for minor modifications, as discussed in Section 14B.5.4.4, the plant will always maintain shutdown capability, and at least one each of the redundant protective features will remain operable following a crack in these high-energy lines.

14B.5.4.4 Modifications

In order to ensure a safe cold shutdown, the following modifications to the initial plant design were made:

1. The charging pump cooling water pumps are shielded from direct impingement, in accordance with Figure 14B-21.
2. One of the four component cooling pump cables is rerouted (shown in Figure 14B-14), so that two of the pumps are always available (only one is required for hot standby).

14B.6 TRANSIENT ANALYSIS OF A HIGH-ENERGY LINE BREAK IN THE MAIN STEAM VALVE HOUSE

A break in a main steam or main feedwater (MFW) pipe in the main steam valve house (MSVH) could be postulated to disable the auxiliary feedwater (AFW) pumps, resulting in a loss of all feedwater on the accident unit. The main feedwater line break (MFLB) is shown to be more severe than the steam line break with respect to core cooling and steam generator inventory reduction. The MFLB in the MSVH is assumed to disable all main and auxiliary feedwater to one of the units. The only source of AFW is from the opposite unit via the AFW cross-connect. This is a limiting assumption that requires operator action within a specified time. Emergency procedures direct the operators to perform mitigating actions for this event. A further limiting assumption is that only a single motor-driven AFW pump (most degraded) is available from the other unit.

This transient is characterized by a rise in the reactor coolant system (RCS) temperature and pressure and the pressurizer water volume due to a reduction in the capability of the secondary system to remove the heat generated in the reactor core and by the reactor coolant pumps (RCPs). AFW delivery via the cross-connect becomes the critical factor for maintaining a secondary heat sink and preventing core damage. The key safety analysis parameters for this transient are the core decay heat, time of AFW cross-connect flow delivery to the accident unit’s steam generators, AFW flow rate and enthalpy, and time of RCP trip.

14B.6.1 Method of Analysis

The high-energy line break event is evaluated by modeling a loss of all MFW and AFW to the affected unit and the initiation of AFW via the cross-connect by operator action as directed by the station emergency procedures. The event was explicitly analyzed at hot full power deterministic conditions. The transient analysis code RETRAN (Reference 17) was used to simulate the reactor coolant system, core kinetics, and the feedwater and steam systems. The 1979 ANS decay heat standard with a two-sigma uncertainty was used to calculate post-trip reactor core heat based on long-term operation at the initial power level preceding the trip. An assumed AFW cross-connect flow rate was selected to be conservatively bounded by the design flow rate from the most degraded AFW pump. AFW enthalpy was based on the highest allowable design temperature in the emergency condensate storage tank.

Two cases were analyzed to demonstrate the plant behavior for a loss of all feedwater event. One case provided the limiting results with respect to the fuel integrity and steam generator dryout (i.e., minimum secondary side liquid inventory) criteria. The other case provided the limiting results for the primary and secondary system overpressure criteria. Reactor trip on a low-low water level in any steam generator provides the necessary protection. Simulator verification runs were performed to provide assurance that the operators can satisfy the analysis assumptions to cross-connect AFW from the unaffected unit and trip the RCPs to maintain the secondary heat sink and to ensure a safe plant shutdown. The analyses demonstrate that the event acceptance criteria are met.

14B.6.2 Results and Conclusions

The loss of all feedwater due to a high-energy line break in the MSVH was analyzed to demonstrate a long-term increase in steam generator inventory after AFW was provided and the secondary system heat removal rate exceeded the heat production by the reactor coolant system. The effects of a high-energy line break in the MSVH are mitigated by operator action in accordance with the emergency procedures. The accident analysis meets all event acceptance criteria (no RCS bulk boiling, no steam generator dryout, peak RCS and main steam system pressures less than the limits).

14B.7 CONCLUSIONS

Surry Units 1 and 2 are designed with highly reliable and redundant systems for the purpose of safe shutdown, considering normal and accident conditions. Furthermore, with the modifications described in the text of this appendix, safe plant shutdown is ensured for all postulated failures of high-energy piping outside of the containment.

The control room, which serves Units 1 and 2, will remain habitable and functional following a failure of any high-energy line.

The emergency diesel generators, which are required to satisfy loss-of-offsite-power criteria, will maintain integrity throughout a postulated high-energy piping failure incident.

14B REFERENCES

1. A. Giambusso, Atomic Energy Commission letter, *General Information Required for Consideration of the Effects of a Piping System Break Outside Containment,* December 18, 1972.
2. General Electric Company, *System Criteria and Applications for Protection Against the Dynamic Effects of Pipe Break,* Document No. 22A2625, Nuclear Energy Division, 1971.
3. PISCES Computer Code, Physics International Multispacial Codes for Engineering and Science, Physics International Company.
4. K. R. Wichman, A. G. Hopper, and J. L. Mershon, *Local Stresses in Spherical and Cylindrical Shells Due to External Loadings*, Welding Research Council.
5. *Building Code Requirements for Reinforced Concrete (ACI 318-71),* American Concrete Institute, 1971.
6. G. Berkhoff and E. H. Zarantonello, *Jets, Wakes, and Cavities*, Academic Press Inc., New York, 1967.

7. *CUPAT - A Computer Program to Calculate Pressure and Temperature in Various Nuclear Power Plant Compartments Resulting from a Postulated High Energy Pipe Break,* Stone & Webster Engineering Corp., 1973.

8. *LOCTIC - A Computer Code to Determine the Pressure and Temperature Response of Dry Containments to a Loss-of-Coolant Accident,* SWND-1, Stone & Webster Engineering Corp., September 1971.

9. *LOCTVS - A Computer Code to Determine the Pressure and Temperature Response of Pressure Suppression Containments to a Loss-of-Coolant Accident,* SWND-2, Stone & Webster Engineering Corp., October 1969.

10. F. J. Moody, *Maximum Two-Phase Vessel Blowdown from Pipes*, APED-4827, General Electric Co., April 20, 1965.

11. *LOCTVS - A Computer Code to Determine the Pressure and Temperature Response of Pressure Suppression Containments to a Loss-of-Coolant Accident,* SWND-2, Supplement No. 1, Stone & Webster Engineering Corp., March 1973.

12. *PVRC Recommendations on Toughness Requirements for Ferritic Materials*, WRC Bulletin 175, August 1972.

13. W. E. Senchak and O. E. Widera, *Application of Fracture Mechanics to Nuclear Piping Systems, Engineering Fracture Mechanics*, 1972, Vol. 4, P. 877.

14. H. Liebowitz, ed., *Fracture - An Advanced Treatise,* Vol. V, 211.

15. *Evaluation of the Toughness of Alternate Materials for Feedwater and Main Steam Piping at Surry and North Anna Power Stations,* Technical Report No. MT-0003, Rev. 0, Material Engineering, Nuclear Engineering Services, Virginia Power, March 1992.

16. Letter dated July 16, 1973, Serial No. 03873, from Virginia Electric and Power Company to U. S. Atomic Energy Commission, Docket Nos. 50-280 and 50-281.

17. *Vepco Reactor System Transient Analyses Using the RETRAN Computer Code*, VEP-FRD-41, Rev. 0.2-A, March 2015.

Table 14B-1
LENGTH OF PLASTIC HINGE POINT

Nominal Pipe Size, in.	Schedule	Length, in.
10	80	97.4
14	80	122.6
24	80	197.8
30	l-inch wall	167.5
32	l-inch wall	155.6
3[a]	80	77.4

Notes: 1. Carbon steel pipe (A106, Grade B).
2. Break at elbow.
3. Steam initially at 1050 psi.

a. Saturated water - 775 psig, 515°F.

Table 14B-2
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
WGCB - 101 Steam generator blowdown	3	0.300	775	515	Pipe whip, jet impingement, environmental	I	Auxiliary building
WGCB - 102 Steam generator blowdown	3	0.300	775	515	Pipe whip, jet impingement, environmental	I	Auxiliary building
WGCB - 103 Steam generator blowdown	3	0.300	775	515	Pipe whip, jet impingement, environmental	I	Auxiliary building
SHP - 133 Capped line	3	0.438	700	505	Pipe whip, jet impingement, environmental	I	Main steam valve house
SLPD - 56 Low-pressure drip line	1	0.179	15	250	Environmental, jet impingement	NA	Auxiliary building
SLPD - 50 Low-pressure drip line	4	0.237	110	344	Environmental, jet impingement	NA	Auxiliary building
SA - 21 Auxiliary steam	6	0.280	150	338	Environmental, jet impingement	NA	Auxiliary building
SA - 29 Auxiliary steam	4	0.237	150	338	Environmental, jet impingement	NA	Auxiliary building

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
SA - 31 Auxiliary steam	1	0.179	150	338	Environmental, jet impingement	NA	Auxiliary building
SHP - 101 Main steam piping - from steam generators to and including main steam trip valve	30	1.0	1005	547	Pipe whip, jet impingement, environmental	I	Containment, main steam valve house
SHP - 101 Main steam piping - from main steam trip valve to main steam manifold	30	1.0	1005	547	Pipe whip, jet impingement, environmental	NA	Main steam valve house, service building, and turbine building
SHP - 102 Main steam piping - from steam generators to and including main steam trip valve	30	1.0	1005	547	Pipe whip, jet impingement, environmental	I	Containment, main steam valve house
SHP - 102 Main steam piping - from main steam trip valve to main steam manifold	30	1.0	1005	547	Pipe whip, jet impingement, environmental	NA	Main steam valve house, service building, and turbine building

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
SHP - 103 Main steam piping - from steam generators to and including main steam trip valve	30	1.0	1005	547	Pipe whip, jet impingement, environmental	I	Containment, main steam valve house
SHP - 103 Main steam piping - from main steam trip valve to main steam manifold	30	1.0	1005	547	Pipe whip, jet impingement, environmental	NA	Main steam valve house, service building, and turbine building
SHP - 122 Main steam piping riser - to and including the safety valve manifold	30	1.0	1005	547	Pipe whip, jet impingement, environmental	I	Containment, main steam valve house
SHP - 123 Main steam piping riser - to and including the safety valve manifold	30	1.0	1005	547	Pipe whip, jet impingement, environmental	I	Main steam valve house
SHP - 124 Main steam piping riser - to and including the safety valve manifold	30	1.0	1005	547	Pipe whip, jet impingement, environmental	I	Main steam valve house

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
WFPD - 109 Steam generator feed line - inside containment to and including first isolation check valve outside containment	14	0.750	1032	450	Pipe whip, jet impingement, environmental	I	Containment, main steam valve house
WFPD - 108/109 Steam generator feed line - from feedwater manifold to but not including first isolation check valve outside containment	14	0.750	1032	450	Pipe whip, jet impingement, environmental	NA	Service building, main steam valve house
WFPD - 113 Steam generator feed line - inside containment to and including first isolation check valve outside containment	14	0.750	1032	450	Pipe whip, jet impingement, environmental	I	Containment, main steam valve house

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
WFPD - 112/113 Steam generator feed line - from feedwater manifold to but not including first isolation check valve outside containment	14	0.750	1032	450	Pipe whip, jet impingement, environmental	NA	Service building, main steam valve house
WFPD - 117 Steam generator feed line - inside containment to and including first isolation check valve outside containment	14	0.750	1032	450	Pipe whip, jet impingement, environmental	I	Main steam valve house
WFPD - 107/117 Steam generator feed line - from feedwater manifold to but not including first isolation check valve outside containment	14	0.750	1032	450	Pipe whip, jet impingement, environmental	NA	Turbine building, service building, main steam valve house

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
WFPD - 106 Steam generator feed line - feedwater manifold	18	1.156	1032	450	Pipe whip, jet impingement, environmental	NA	Service building
WFPD - 104 Steam generator feed line - feedwater pumps to feedwater manifold	18	1.156	1032	450	Pipe whip, jet impingement, environmental	NA	Turbine building, service building
CH - 391 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 313 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building
CN - 312 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 414 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
CH - 381 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 369 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 321 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 302 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 370 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH -322 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building
WFPD - 105 Steam generator feed line - feedwater pumps to feedwater manifold	18	1.156	1032	450	Pipe whip, jet impingement, environmental	NA	Turbine building, service building

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
CH - 306 Chemical and volume control - letdown from regenerative heat exchanger	2	0.154	289	287	Pipe whip, jet impingement, environmental	I	Auxiliary building
CH - 380 Chemical and volume control - charging header	4	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 389 Chemical and volume control - charging header	4	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 379 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CN - 311 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 308 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
CH - 390 Chemical and volume control	2	0.343	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 303 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
CH - 371 Chemical and volume control	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
SI - 347 Safety injection charging pump - to and including the first isolation valve	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building
SI - 257 Safety injection charging pump - to and including the first isolation valve	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building

a. NA - not applicable

Table 14B-2 (CONTINUED)
HIGH-ENERGY LINES SOURCES

Service	Nominal Line Size, in.	Wall Thickness, in.	Maximum Operating Pressure, psig	Maximum Operating Temperature, °F	Pipe Break Effects Evaluated	Seismic Classification[a]	Location
SI - 272 Safety injection charging pump - to and including the first isolation valve	3	0.438	2500	130	Environmental, jet impingement	I	Auxiliary building

a. NA - not applicable

Table 14B-3
POSTULATED TARGETS

System	Major Equipment	Mark No.	Location
Auxiliary feedwater	Auxiliary feed pumps	2-FW-P-2 2-FW-P-3A 2-FW-P-3B	Main steam valve house (MSVH)
	Auxiliary feed pump oil coolers (1 per feed pump)	2-FW-E-7 2-FW-E-8 2-FW-E-9	MSVH
	Auxiliary feed check valves (1 per feed pump)	2-FW-142 2-FW-157 2-FW-172	MSVH
Chemical and volume control	Charging pumps	2-CH-P-1A 2-CH-P-1B 2-CH-P-1C	Auxiliary building
	Boric acid tanks	1-CH-TK-1A l-CH-TK-1B 1-CH-TK-1C	Auxiliary building
	Boric acid tank heaters	1-CH-E-6A 1-CH-E-6B 1-CH-E-6C	Auxiliary building
	Boric acid transfer pumps	1-CH-P-2C 1-CH-P-2D	Auxiliary building
	Boric acid isolation valves	MOV-2350	Auxiliary building
	Volume control tank isolation check valve	2-CH-230	Auxiliary building
	Cold-leg isolation valves (normal charging)	MOV-2289A MOV-2289B	Auxiliary building
	Charging pump discharge valves	MOV-2286A MOV-2286B MOV-2286C MOV-2287A MOV-2287B MOV-2287C	Auxiliary building
	Reactor coolant pump seal isolation valve	MOV-2370	Auxiliary building
	Refueling water storage tank isolation valves	LCV-2115B LCV-2115D	Auxiliary building

Table 14B-3 (CONTINUED)
POSTULATED TARGETS

System	Major Equipment	Mark No.	Location
Chemical and volume control (continued)	Alternate charging paths - isolation valves (redundancy)	FCV-2160 MOV-2867A MOV-2867B MOV-2867C MOV-2867D MOV-2869A MOV-2869B MOV-2842	Auxiliary building
	Charging pump discharge pressure (not required because of the availability of pressurizer level)	PT-2121	Auxiliary building
	Charging pump flow transmitter (not required because of the availability of pressurizer level)	FT-2122	Auxiliary building
	Flow control valve for the charging pump (fails open)	FCV-2122	Auxiliary building
Main feedwater	Main feedwater isolation check valves (3)	2-FW-12 2-FW-43 2-FW-74	MSVH
Main steam	Main steam nonreturn valves	NRV-MS201A NRV-MS201B NRV-MS201C	MSVH
	Main steam trip valves	TV-MS201A TV-MS201B TV-MS201C	MSVH
	Auxiliary feed pump steam isolation valve	PCV-MS202A PCV-MS202B (F/open)	MSVH MSVH
	Main steam safety valves (required only for main steam line rupture)	SV-MS201A SV-MS201B SV-MS201C SV-MS202A SV-MS202B SV-MS202C SV-MS203A SV-MS203B SV-MS203C	MSVH
	Main steam power operated relief valves (control cooling of the RCS)	RV-MS201A RV-MS201B RV-MS201C	MSVH

Table 14B-3 (CONTINUED)
POSTULATED TARGETS

System	Major Equipment	Mark No.	Location
Component cooling system	Component cooling water pumps	l-CC-P- lA 1-CC-P-1B 1-CC-P-1C 1-CC-P-1D	Auxiliary building
	Charging pump cooling water pumps	2-CC-P-2A 2-CC-P-2B	Auxiliary building
	Charging pump lube-oil coolers	2-CH-E-5A 2-CH-E-5B 2-CH-E-5C	Auxiliary building
	Charging pump seal coolers	2-CH-E-7A 2-CH-E-7B 2-CH-E-7C 2-CH-E-7D 2-CH-E-7E 2-CH-E-7F	Auxiliary building
	Flow transmitters, component cooling pump discharge (Unit 2)	FT-CC200A FT-CC200B	Auxiliary building

Table 14B-4
MAIN STEAM BREAK LOCATIONS AND STRESSES

Line Designation	Break Point	Thermal Stress, psi	Combined Stress, psi	Description
30-SHP-101	1	3850	15,937	Terminal - containment
	79	2560	11,727	Terminal - manifold
	3	6680	19,322	Intermediate - elbow valve house
	37	5330	14,718	
	40	5670	15,068	Intermediate location - bend
30-SHP-102	135	4380	17,484	Terminal - containment
	206	1965	10,335	Terminal - manifold
	138	7355	20,671	Intermediate - elbow valve house
	163	5690	15,116	
	166	6060	15,240	Intermediate location - bend
30-SHP-103	275	4365	17,528	Terminal - containment
	341	1180	9508	Terminal - manifold
	277	7210	18,257	Intermediate - elbow valve house
	309	6565	15,485	
	305	5990	14,910	Intermediate location - bend

Table 14B-5
FEEDWATER SYSTEMS AVAILABILITY AFTER MAIN STEAM PIPE BREAK IN VALVE HOUSE

Break No.	Location	Main Feed	Auxiliary Feed		Auxiliary Feed Cross-Connect
			Turbine	Motors (2)	
C1, C135, C275	Containment	0	0	X-S	0
C2, C136, C276, C461	Riser	0	0	X-S	0
C3, C138, C277	Elbow	0	0	X-S	0
L1, L135, L275	Containment	0	0	X-S	0
L2, L136, L276, L461	Riser	(0)-J	0	X-S	0
L3, L138, L277	Elbow (vertical)	0	X-J	X-S	0
	Elbow (lateral)	0	0	X-S	0

Key: 0 = operable
X = inoperable
(0) = 2 lines operable
W = whip damage
J = jet damage
S = steam damage
C = circumferential
L = longitudinal

Table 14B-6
JET IMPINGEMENT ON WALLS - FORCE = 619 kips

Target	Impingement Area, ft^2	Jet Pressure, psig	Wall Thickness, in.	Min. Wall-Punch Shear, in.
Floor	44.90	95.7	9	22
Roof	142.05	30.2	24	24
Containment (N)	10.23	420.0	54	54
Shield (S)	102.63	41.9	36	36
East wall	18.85	228.1	24	24
West wall	42.23	102.1	24	24
Shield (S)	26.97	159.4	36	36

Table 14B-7
JET IMPINGEMENT ON VALVES

Valves	Pt Jet Pressure, psig	At Impingement Area, in^2	Incident Angle	Fv Normal Force-kips
NRV/MS201B	74.6	3927	0	175
TV/MS201B	126.3	2182	0	165
SV/MS203A	37.8	673	60	3.8
SV/MS201A	37.8	312	60	1.8
RV/MS201A	34.2	200	25	2.8

Table 14B-8
FEEDWATER BREAK LOCATIONS AND STRESSES

Line Designation	Break Point	Thermal Stress, psi	Description
14-WFPD-117	1	1565	Terminal - containment
	76	6563	Terminal - manifold
	72	5837	Intermediate - valve
	4	5383	Intermediate - elbow valve house
14-WFPD-113	101	2393	Terminal - containment
	100	4722	Terminal - manifold
	107	5333	Intermediate - elbow valve house
	171	5466	
	172	5046	Intermediate - at valve
14-WFPD-109	241	2860	Terminal - containment
	195	4200	
	210	4169	Terminal - manifold
	247	11,171	
	249	11, 962	Intermediate - elbow valve house
	244	8814	
	246	7989	Intermediate - elbow valve house
18-WFPD-104	90	3539	Terminal - manifold
	93	5333	Terminal - 2-PW-E1A
	108	4798	Intermediate - bend
	95	6368	Intermediate - bend - valve
18-WFPD-105	190	5209	Terminal - manifold
	14	3260	Terminal - 2-PW-E1B
	48	3220	Intermediate - bend
	16	4460	Intermediate - bend - valve

Table 14B-9
FEEDWATER SYSTEMS AVAILABILITY AFTER MAIN FEEDWATER PIPE BREAK IN VALVE HOUSE

			Auxiliary Feed		
Break No.	Location	Main Feed	Turbine	Motors (2)	Auxiliary Feed Cross-Connect
C5, C6	Containment or elbow	(0)	0	X-S	0
C101, C241, C244	Containment or elbow	(0)	X-W	X-S	0
C107, C247, C249	Elbow	(0)	0	X-S	0
L5, L101, L241	Containment	(0)	0	X-S	0
L6, L244	Elbow	(0)	0	X-S	0
L107	Elbow	(0)	0	X-S	0
L247, L249	Elbow	(0)	0	X-S	0

Key: 0 = operable
X = inoperable
(0) = 2 lines operable
W = whip damage
J = jet damage
S = steam damage
C = circumferential
L = longitudinal

Table 14B-10
STEAM GENERATOR BLOWDOWN BREAK LINE LOCATIONS AND STRESSES

Line Designation	Break Point	Thermal Stress, psi	Description
		Unit 1	
3-WGCB-1	60	3952	Terminal - containment
	61	4991	Intermediate - elbow
3-WGCB-2	63	1414	Terminal - containment
	66	4411	Intermediate - elbow
3-WGCB-3	67	3251	Terminal - containment
	70	4942	Intermediate - elbow
		Unit 2	
3-WGCB-101	22	3952	Terminal - containment
	21	4991	Intermediate - elbow
3-WGCB-102	23	1414	Terminal - containment
	26	4411	Intermediate - elbow
3-WGCB-103	27	3251	Terminal - containment
	30	4942	Intermediate - elbow

Table 14B-11
LETDOWN LINE FROM REGENERATIVE HEAT EXCHANGER
BREAK LOCATIONS AND STRESSES

Line Designation	Break Point	Thermal Stress, psi	Description
		Unit 1	
2"- CH-6-602	238	5102	Terminal - anchor
	236	17,175	Intermediate - elbow
	71	2487	Terminal - containment
	73	2727	Elbow
	74	2774	Elbow
	64	90	Anchor
		Unit 2	
2"- CH-306-602	38	5102	Terminal - anchor
	36	17,175	Intermediate - elbow
	35	2487	Terminal - containment
	32	2727	Elbow
	33	2774	Elbow
	95	90	Anchor

Table 14B-12

PIPE BREAK/MINI-CRACK ANALYSIS SUMMARY

STONE & WEBSTER ENGINEERING CORPORATION
CALCULATION SHEET

Page No. 6
Preliminary
Final

Client VEPCO Location SURRY NO. 2
Subject or Apparatus
Date 3-21-73
Checked 3-22-73
Revised
Based on ONSITE INSPECTION

REF DWG No:
MSK No:

PIPE BREAK/ MINI-CRACK ANALYSIS SUMMARY

* CB - CIRCUMFERENTIAL BREAK
LB - LONGITUDINAL BREAK
MC - MINI CRACK (1/2 OD x 1/2 THICK)

** NR - NOT REQUIRED
R - REQUIRED

Max.Oper.Press. 775 psig
Max.Oper.Temp. 515 F

			PIPE WHIP			PIPE JET					
LINE	POINT	FAILURE TYPE *	BLOWDOWN FORCE (KIPS)	RESTRAINT **	DESCRIPTION AND COMMENTS	TARGET	TARGET DISTANCE (FT)	JET FORCE ON TARGET (KIPS)	BARRIER **	DESCRIPTION AND COMMENTS	RECOMMENDATIONS
MOCB-102	26	CB	7.1		Column TH-9' prevents the pipe from whipping in the eastward direction. For movement in other directions the hinge length of 77.4 in. was used to determine "target" damage. There were no "targets" within this distance. The normal charging line 3"-CH-379-1503 and the normal seal injection line for the reactor coolant pumps 3"-CH-313-1503 will not be damaged because of the criteria for whipping pipes. Line 2"-CH-390-1503 is only an alternate seal injection line to the reactor coolant pumps, and is therefore not required.	MOV-2289A MOV-2289B	10 13			Possible damage from direct impingement. These are redundant isolation valves which are normally open and will fail open. Furthermore this line can be isolated at the charging pumps, if necessary. The line which includes these valves is the normal charging path for chemical and volume control. An alternate path is 2"-CH-308-1503 (located at drawing coordinate E-2), could be used to shut the unit down in a normal manner. Therefore, there are no adverse effects on safe shutdown and no analysis on the effects of the two valves is required.	Plant must be shut down and repairs made.
						MOV-2370 MOV-2867C MOV-2867D	8 15 18			Valves are protected from jet impingement by column TH-9', distance, and location. Failure by fluid jets is therefore not credible. The power cables to these motor operated valves could be severed. MOV-2370 is an isolation valve for isolation of normal seal water injection to the reactor coolant pump seals. This valve will fail as is (open). Valve operation is not required for safe shutdown. MOV-2867C & D are redundant isolation valves which require operation only in the event of a loss-of-coolant accident (13A) or a major main steam line rupture. Therefore, there are no adverse effects on safe plant shutdown.	Plant must be shut down and repairs made.

S14B0024

Table 14B-13
PIPE BREAK/MINI-CRACK ANALYSIS SUMMARY

STONE & WEBSTER ENGINEERING CORPORATION
CALCULATION SHEET

Page No. 73

VEPCO — SURRY NO. 2 — J.O. No. 12358
Date 3-21-73
Checked 3-22-73
ON-SITE INSPECTION

REF DWG No:
MSK No:

PIPE BREAK/MINI-CRACK ANALYSIS SUMMARY

* CB - CIRCUMFERENTIAL BREAK
LB - LONGITUDINAL BREAK
MC - MINI CRACK (1/2 OD x 1/2 THICK)

** NR - NOT REQUIRED
R - REQUIRED

Max Oper. Press. 150 psig
Max Oper. Temp 338 °F

			PIPE WHIP			PIPE JET					
LINE	POINT	FAILURE TYPE *	BLOWDOWN FORCE (KIPS)	RESTRAINT **	DESCRIPTION AND COMMENTS	TARGET	TARGET DISTANCE (FT)	JET FORCE ON TARGET (KIPS)	BARRIER **	DESCRIPTION AND COMMENTS	RECOMMENDATIONS
8A-29 4"	#26	MC	None	NR	Line only analyzed for environmental effects.	CC-P-1A	0.5	NR	NR	Power cables for these component cooling pumps could be severed or permanently damaged. The fourth component cooling pump will not be affected. One pump is sufficient to maintain both units in a hot shutdown condition. Since the single active failure criteria must be applied; see Recommendations to assure a safe shutdown.	Reroute one of the three component cooling pump cables; so that the most adverse crack could only severe or permanently damage only two pump cables.
						CC-P-1B	0.5	NR	NR		
						CC-P-1C	0.5	NR	NR		
						CH-P-1A	4	NR	NR	If crack is moved to the most adverse location and orientation, there may be possible damage on the power cable to this charging pump. Since there are two other pumps available and only one is required, safe shutdown is still assured.	NR
						FCV-1113A	11	NR	NR	Because of the low steam line pressure and distance, valve is probably not subject to environmental failure. Of course, this valve is normally open and fails open, so even a failure of this valve will not effect safe shutdown. Valve used for normal boric acid transfer to charging pumps.	NR
										Point 26 denotes the area surround: TW16 on Fig. D.4-3. Cracks are assumed anywhere in this area.	

S14B0025

Table 14B-13 (CONTINUED)
PIPE BREAK/MINI-CRACK ANALYSIS SUMMARY

STONE & WEBSTER ENGINEERING CORPORATION
CALCULATION SHEET

Page No. 76

Client VEPCO   Location SURRY NO. 2   J.O. No. 12354
Date 3-21-73   By [illegible]
Checked 3-22-73   By [illegible]
Based on ON-SITE INSPECTION

REF DWG No:
MSK No:

PIPE BREAK/MINI-CRACK ANALYSIS SUMMARY

* CB - CIRCUMFERENTIAL BREAK; LB - LONGITUDINAL BREAK; MC - MINI CRACK (1/2 OD x 1/2 THICK)
** NR - NOT REQUIRED; R - REQUIRED

Max. Oper. Press. 150 psig
Max. Oper. Temp 338°F

			PIPE WHIP			PIPE JET					
LINE	POINT	FAILURE TYPE *	BLOWDOWN FORCE (KIPS)	RESTRAINT **	DESCRIPTION AND COMMENTS	TARGET	TARGET DISTANCE (FT)	JET FORCE ON TARGET (KIPS)	BARRIER **	DESCRIPTION AND COMMENTS	RECOMMENDATIONS
8A-29 4"	#26	MC	None	NR	Line only analyzed for environmental effects.	MOV-1350	12	NR	NR	Because of low steam line pressure and distance, valve is probably not subject to environmental failure. Of course, this valve is only an isolation valve for one of the many alternate methods for boric acid feed to the charging pumps. Therefore, failure will not effect a safe shutdown.	NR
						CH-E-6A	8	NR	NR	Because of low steam line pressure and distance, failure of the power cable to this heater is not likely. If failure occurred, there is a redundant power cable for this heater north of the boric acid tank in question. Furthermore, boric acid tanks 1-CH-TK-1B and 1-CH-TK-1C are available back-up sources of boric acid. Therefore, failure will not effect a safe shutdown.	NR
										Point 26 denotes the area surrounding TN16 on Fig. D.4-3. Cracks are assumed anywhere in this area.	

S14B0026

Figure 14B-1
APPENDIX ORGANIZATION—EFFECTS OF HIGH ENERGY PIPING SYSTEM BREAK OUTSIDE CONTAINMENT

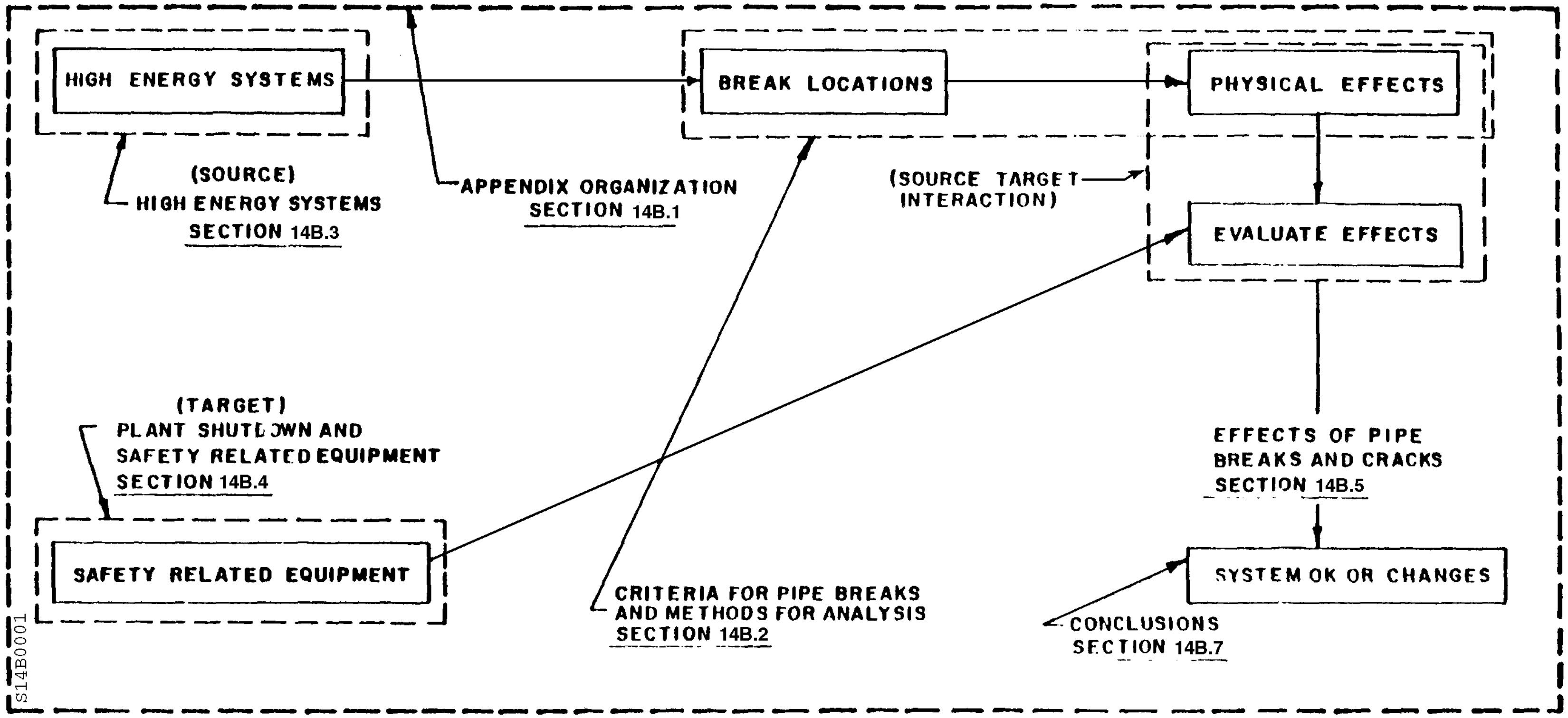
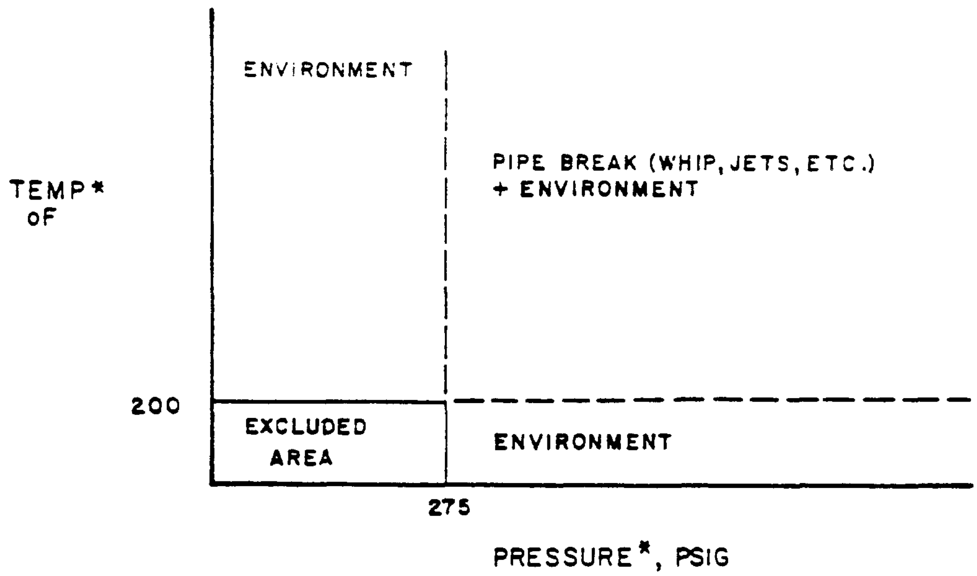


Figure 14B-2
PIPE SPLIT, CRACK AND BREAK ANALYSIS REQUIRED FOR HIGH ENERGY PIPING



* PRESSURE AND TEMPERATURE CORRESPONDING TO "MAXIMUM NORMAL OPERATING"
INCLUDES START—UP, SHUTDOWN, STANDBY, POWER OPERATION

S14B0002

Figure 14B-3
MATHEMATICAL MODEL AND FORCING FUNCTIONS

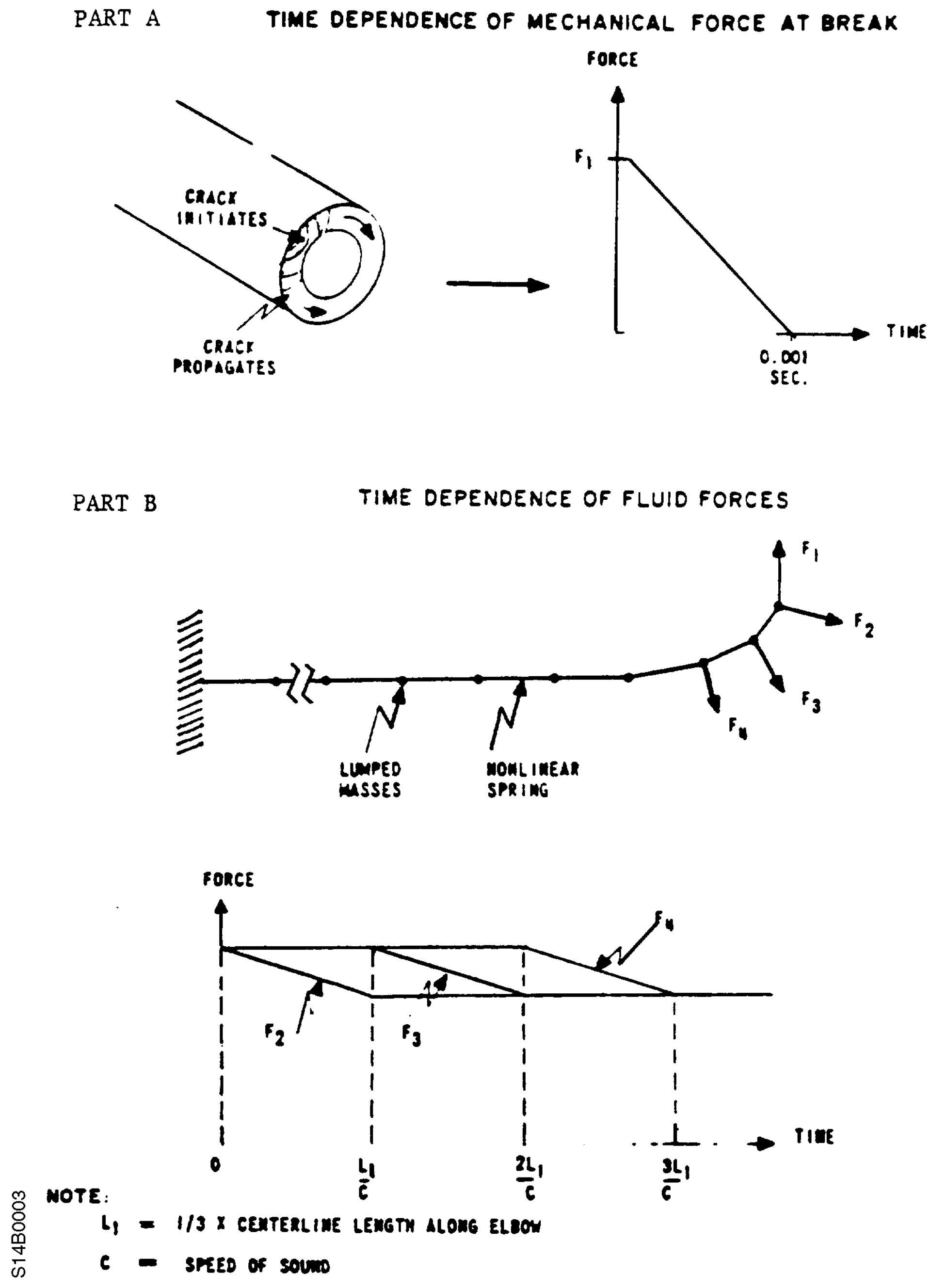


Figure 14B-4
FORCE DUE TO PIPE IMPACT (TYPICAL EXAMPLES)

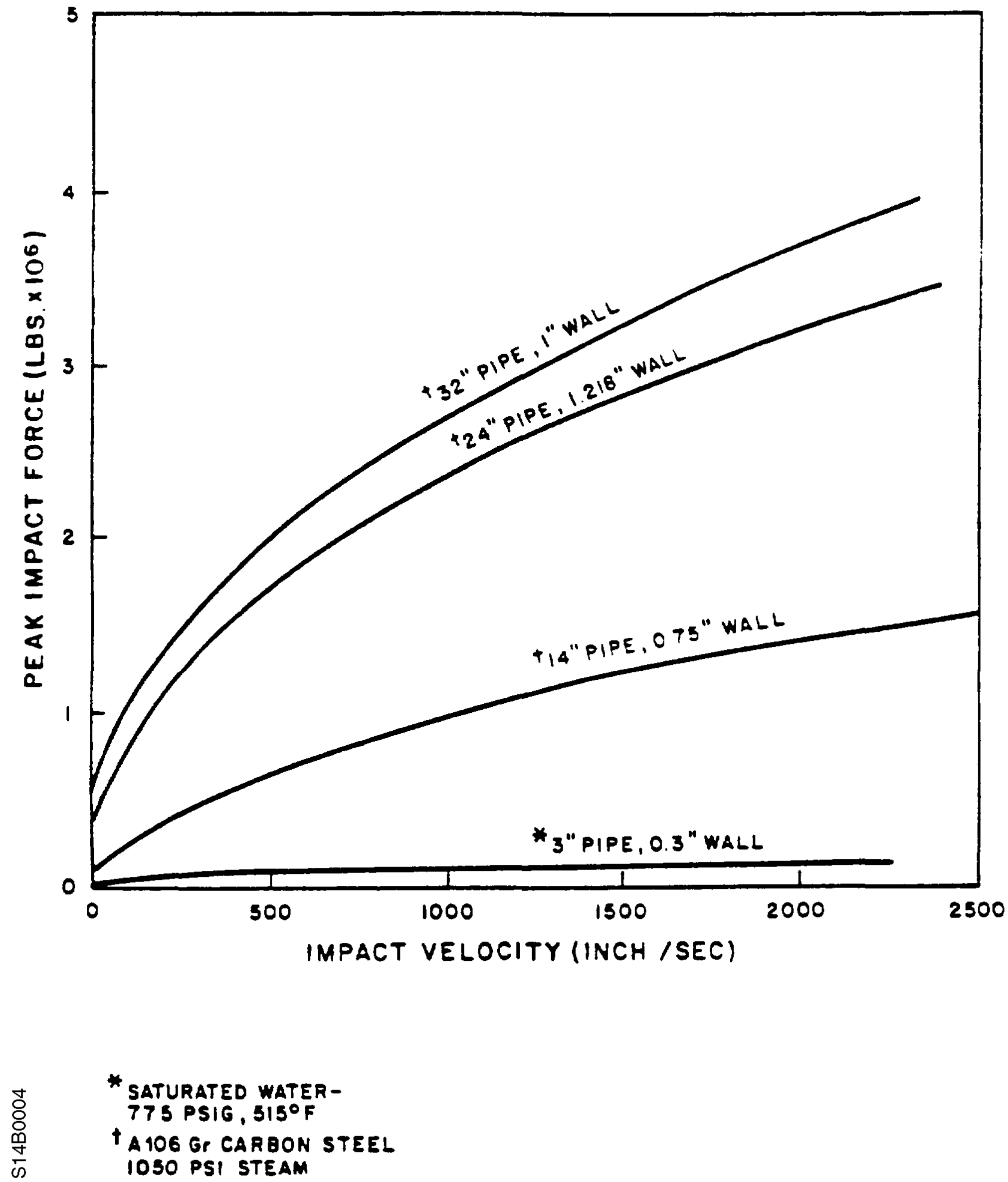


Figure 14B-5
PUNCHING SHEAR IN CONCRETE WALL

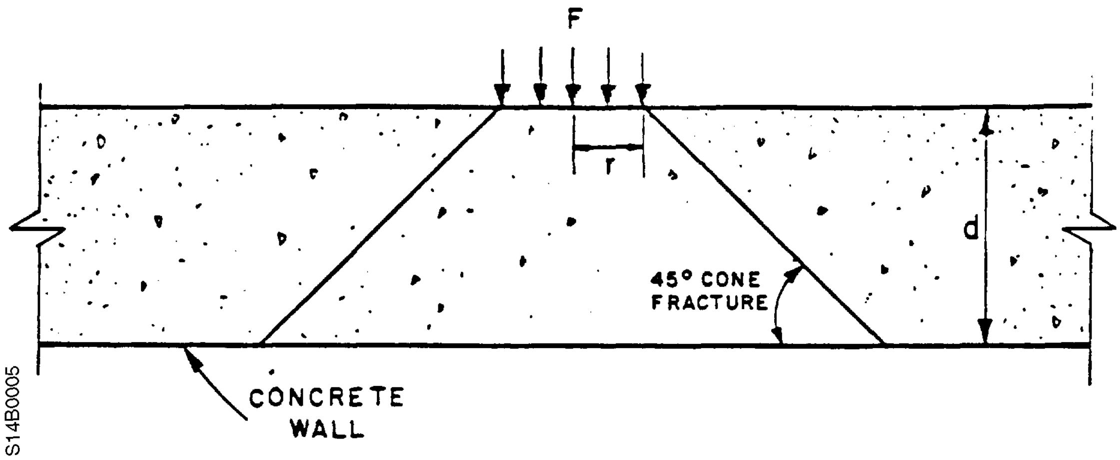
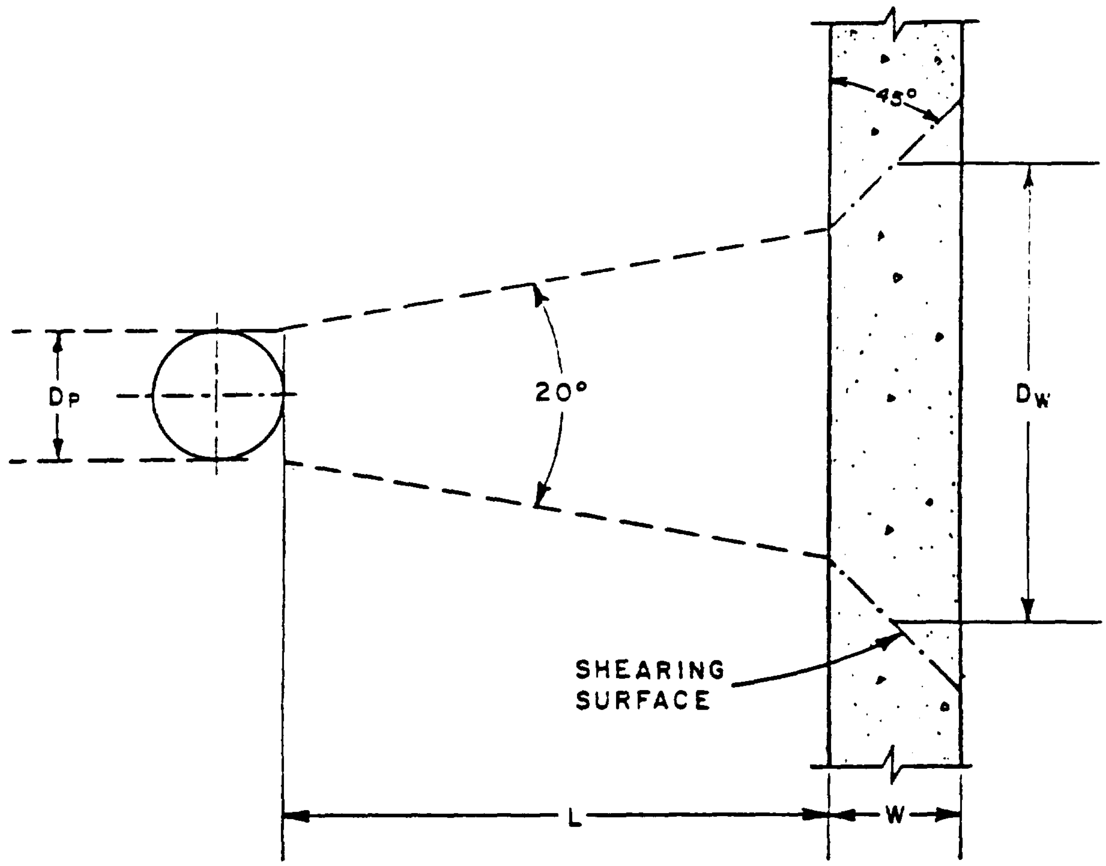


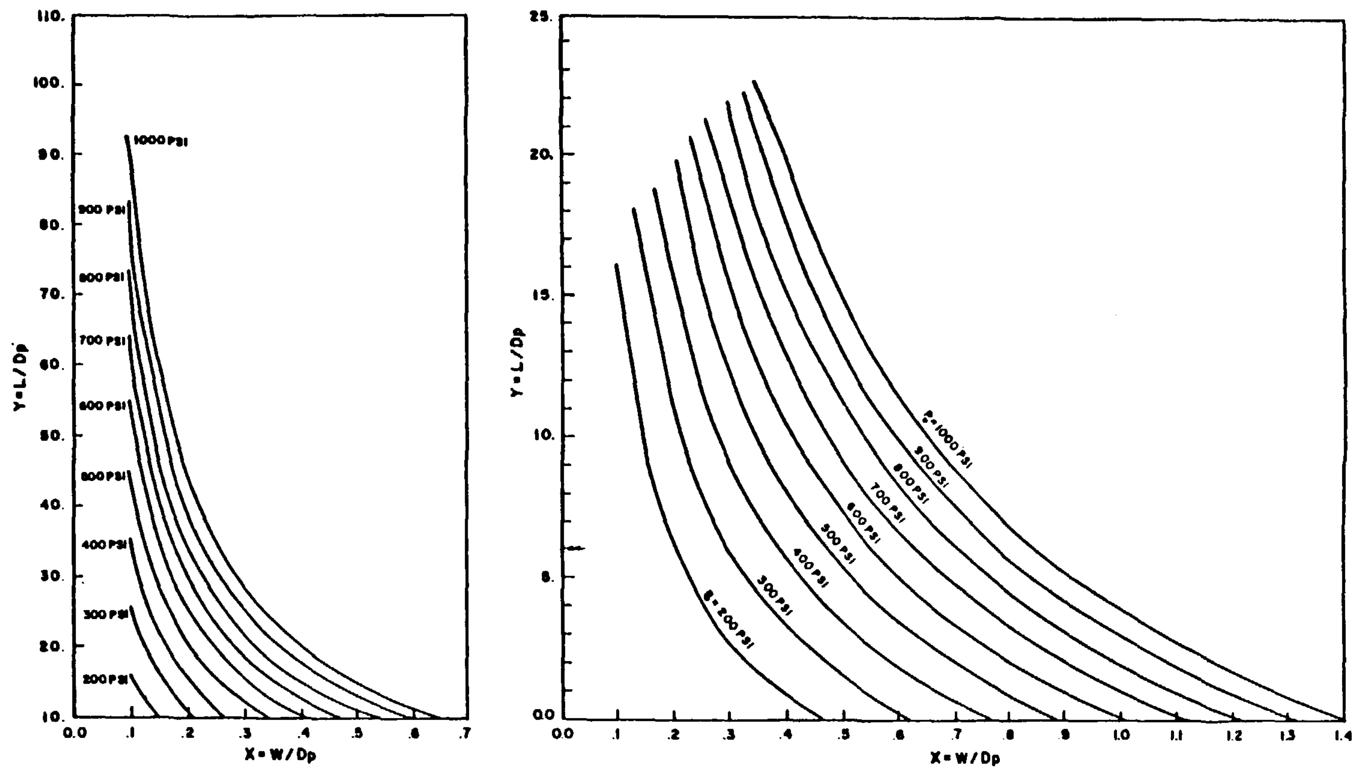
Figure 14B-6
PUNCH SHEAR FAILURE OF CONCRETE WALL



NOTE:
THIS ANALYSIS IS BASED ON THE DOUBLE ENDED BREAK MODEL WHICH GIVES MORE CONSERVATIVE RESULT THAN THE LONGITUDINAL BREAK MODEL DOES.

S14B0006

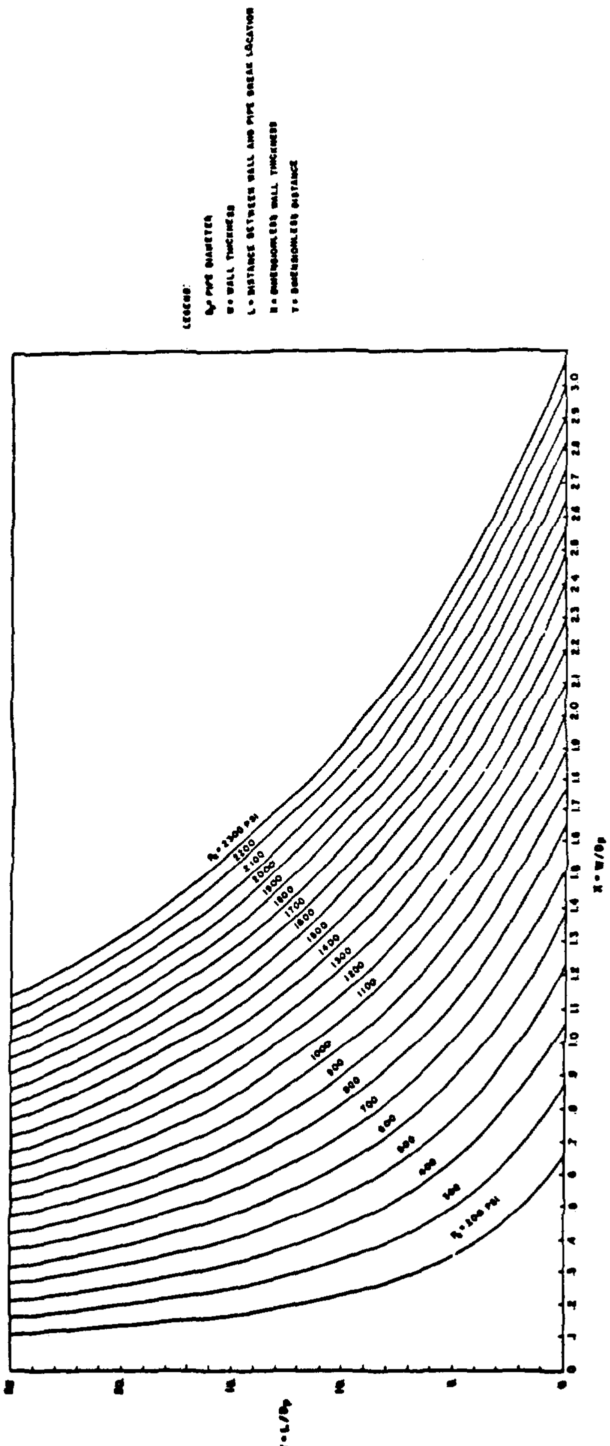
Figure 14B-7
PUNCH SHEAR OF REINFORCED CONCRETE WALL DUE TO JET IMPINGEMENT FROM
STEAM PIPE BREAK



LEGEND:
Dp = PIPE DIAMETER
W = WALL THICKNESS
L = DISTANCE BETWEEN WALL AND PIPE BREAK LOCATION
X = DIMENSIONLESS WALL THICKNESS
Y = DIMENSIONLESS DISTANCE

S14B0007

Figure 14B-8 (SHEET 1 OF 2)
PUNCH SHEAR OF REINFORCED CONCRETE WALL DUE TO JET IMPINGEMENT
FROM WATER PIPE BREAK



S14B0008

Figure 14B-8 (SHEET 2 OF 2)
PUNCH SHEAR OF REINFORCED CONCRETE WALL DUE TO JET IMPINGEMENT FROM WATER PIPE BREAK

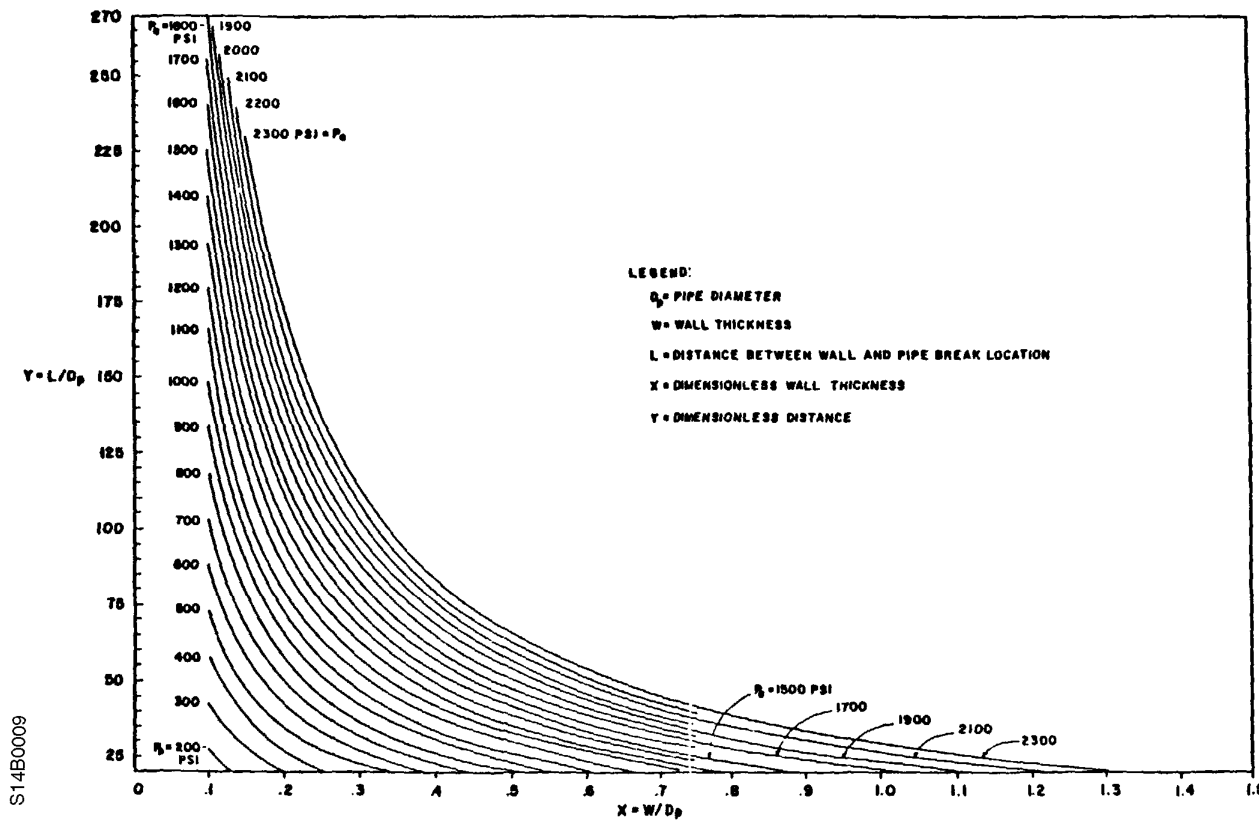


Figure 14B-9
CUPAT LOGIC DIAGRAM

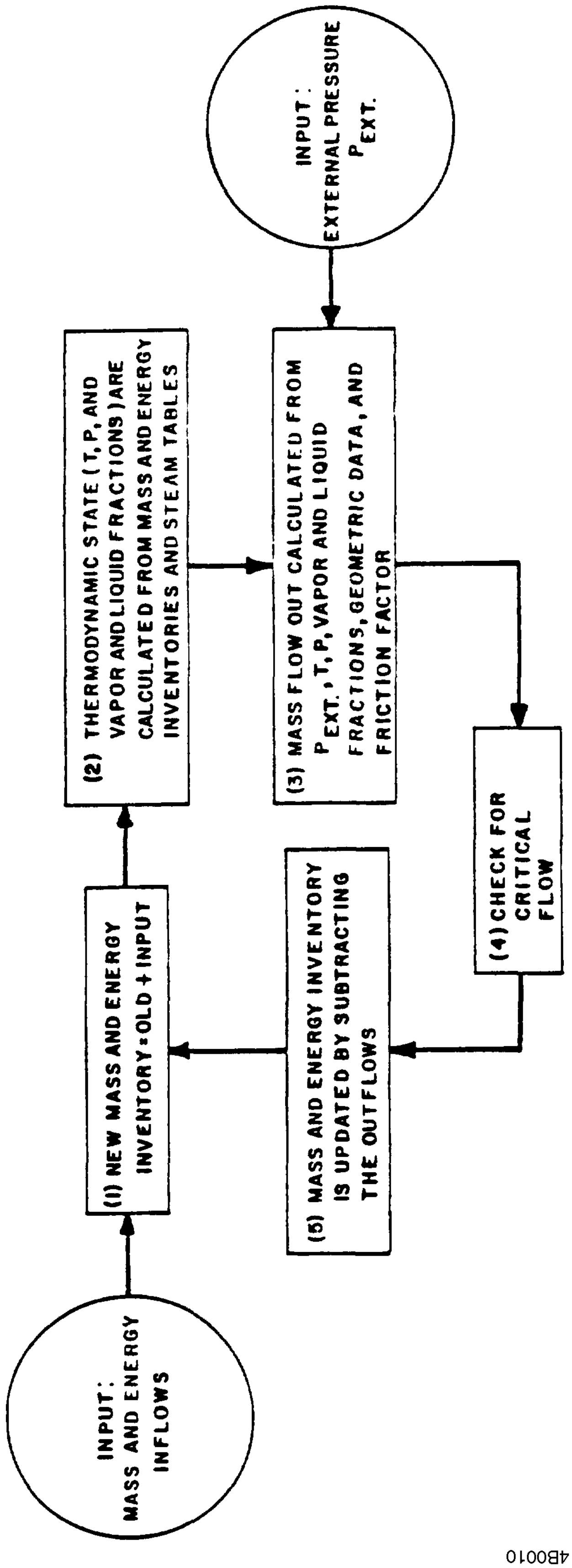
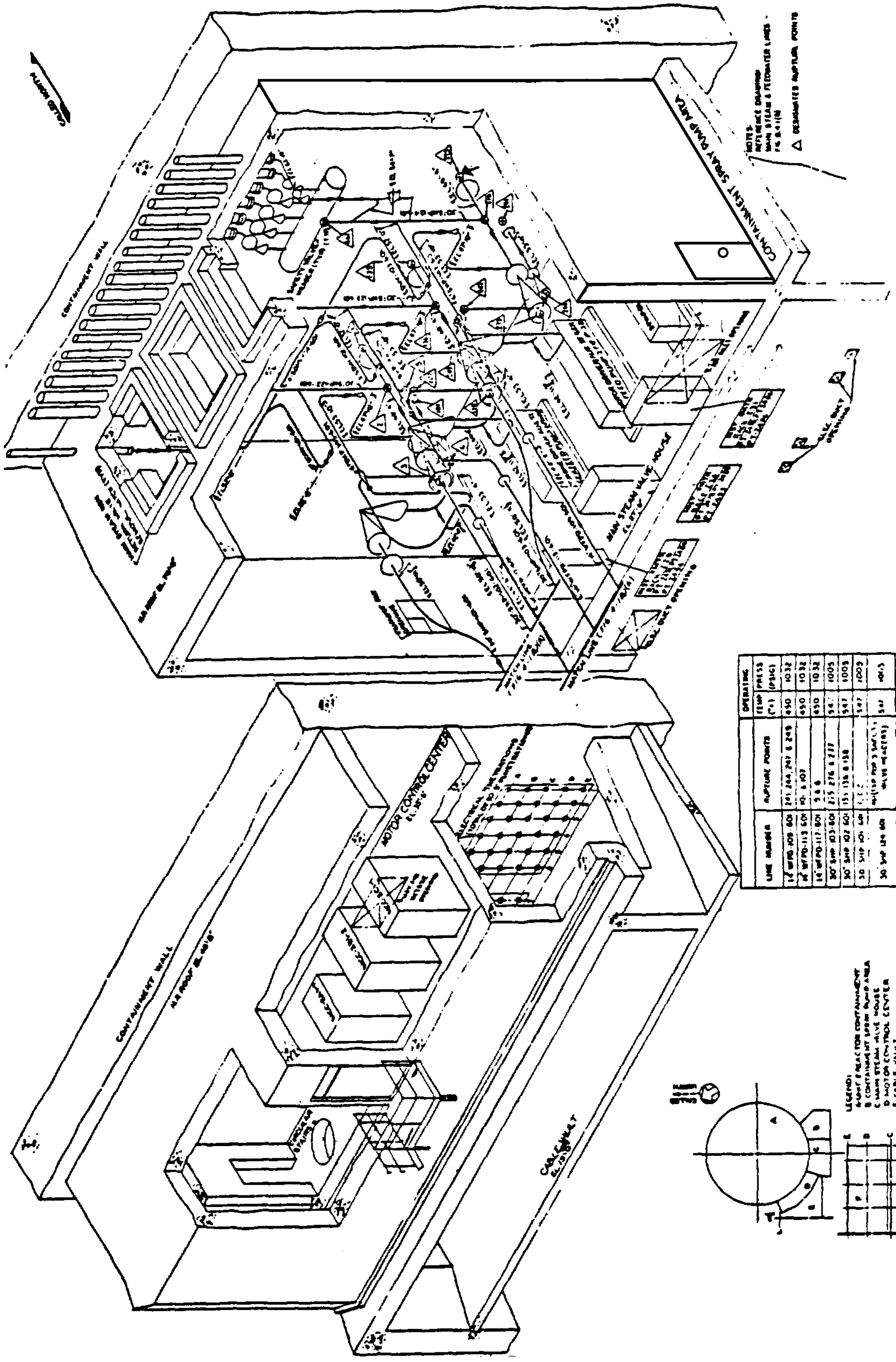


Figure 14B-10 (SHEET 1 OF 2)
MAIN STEAM AND FEEDWATER LINES-UNIT 2



S14B0011

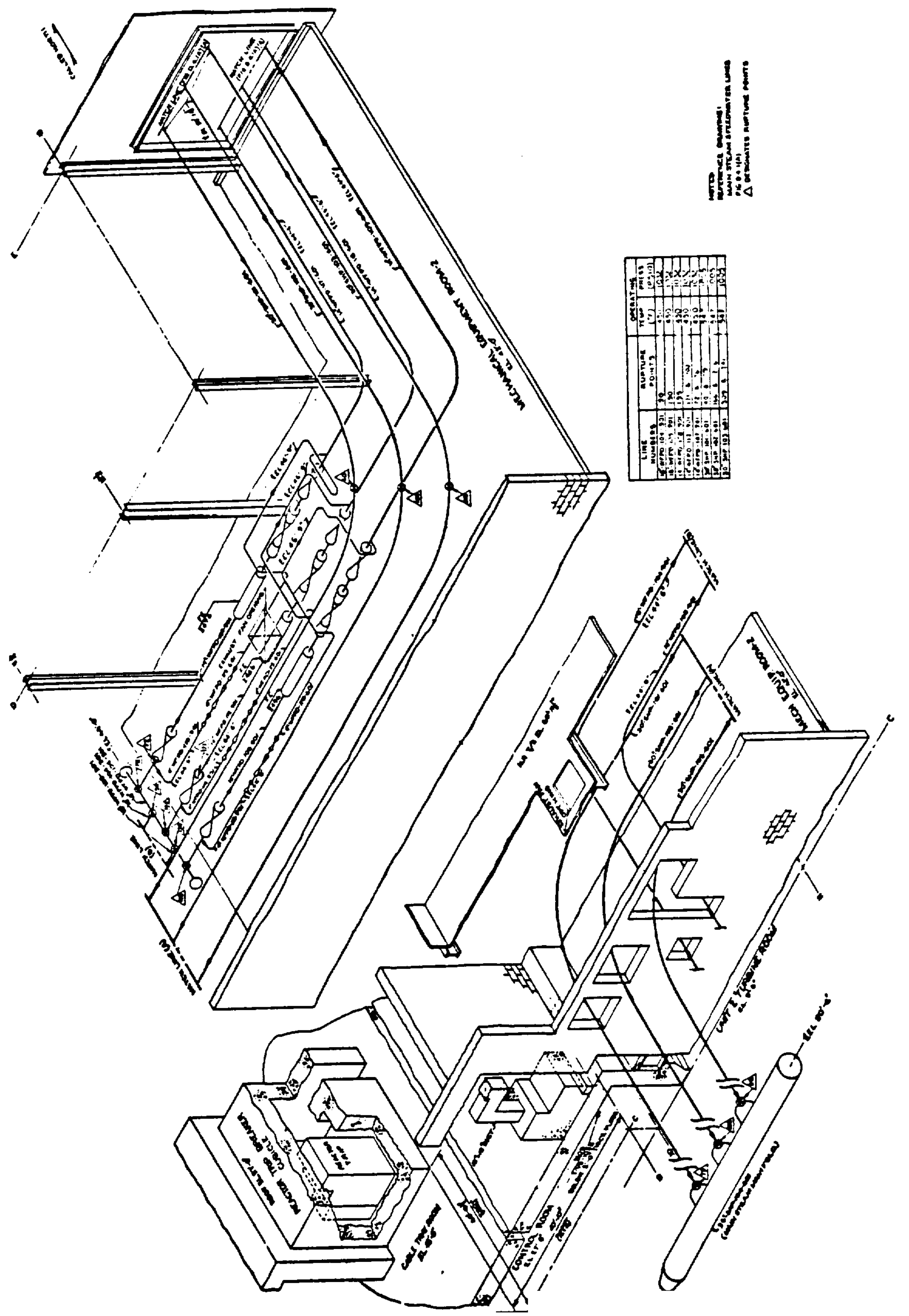


Figure 14B-10 (SHEET 2 OF 2)
MAIN STEAM AND FEEDWATER LINES-UNIT 2

S14B0012

Figure 14B-11
AUXILIARY BUILDING SOURCES AND TARGETS-UNIT 2 SHEET 1

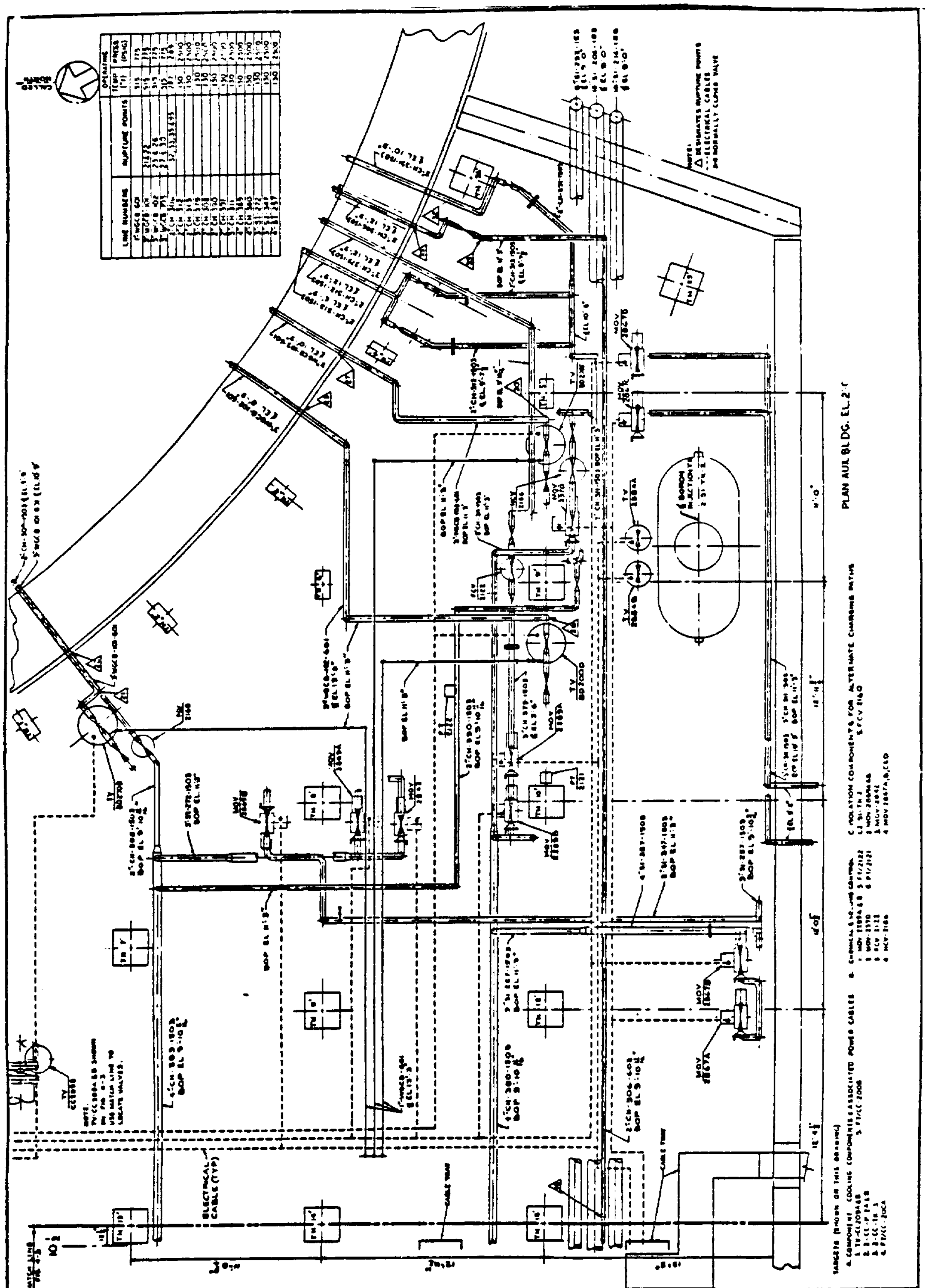


Figure 14B-12
AUXILIARY BUILDING SOURCES AND TARGETS SHEET 2

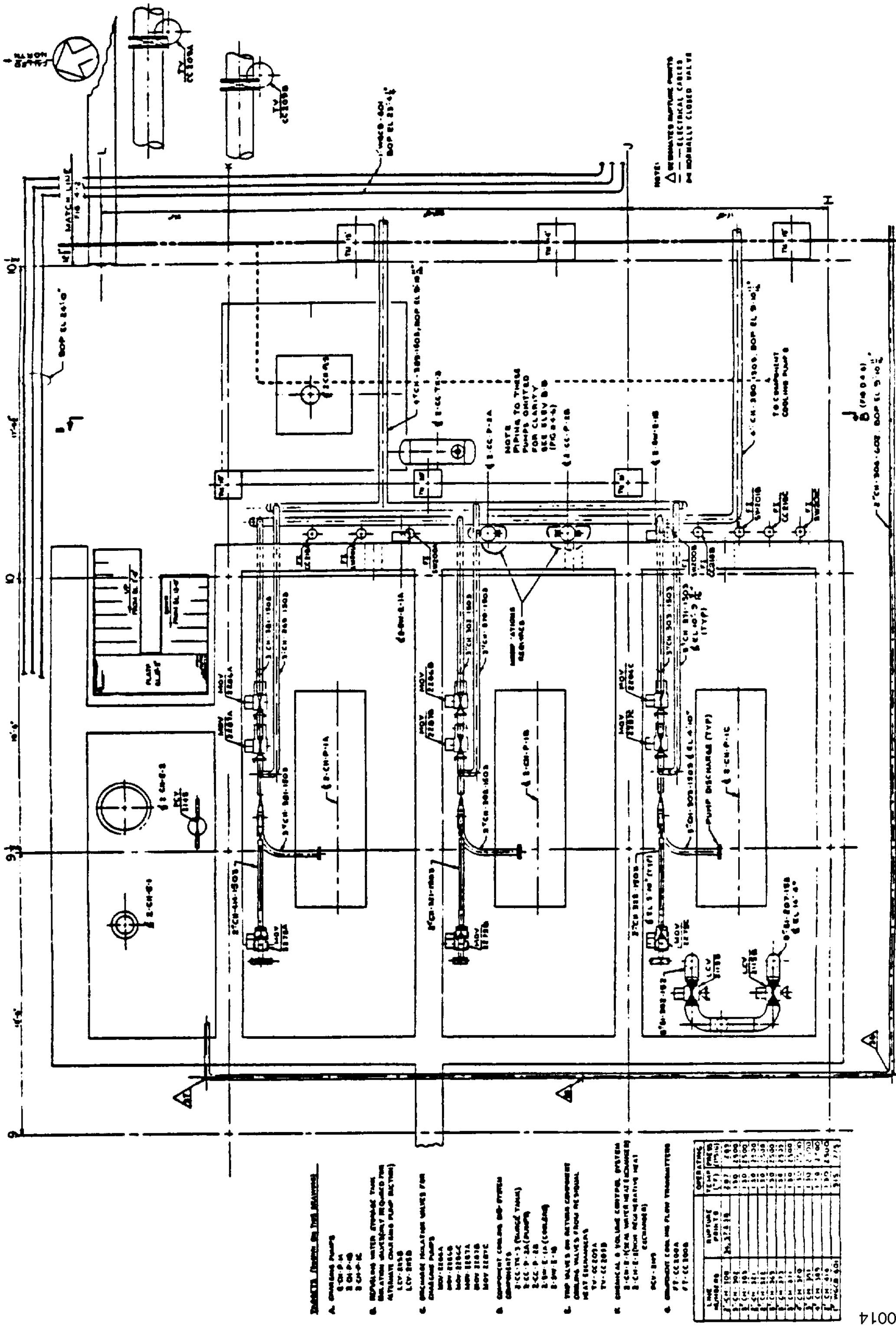
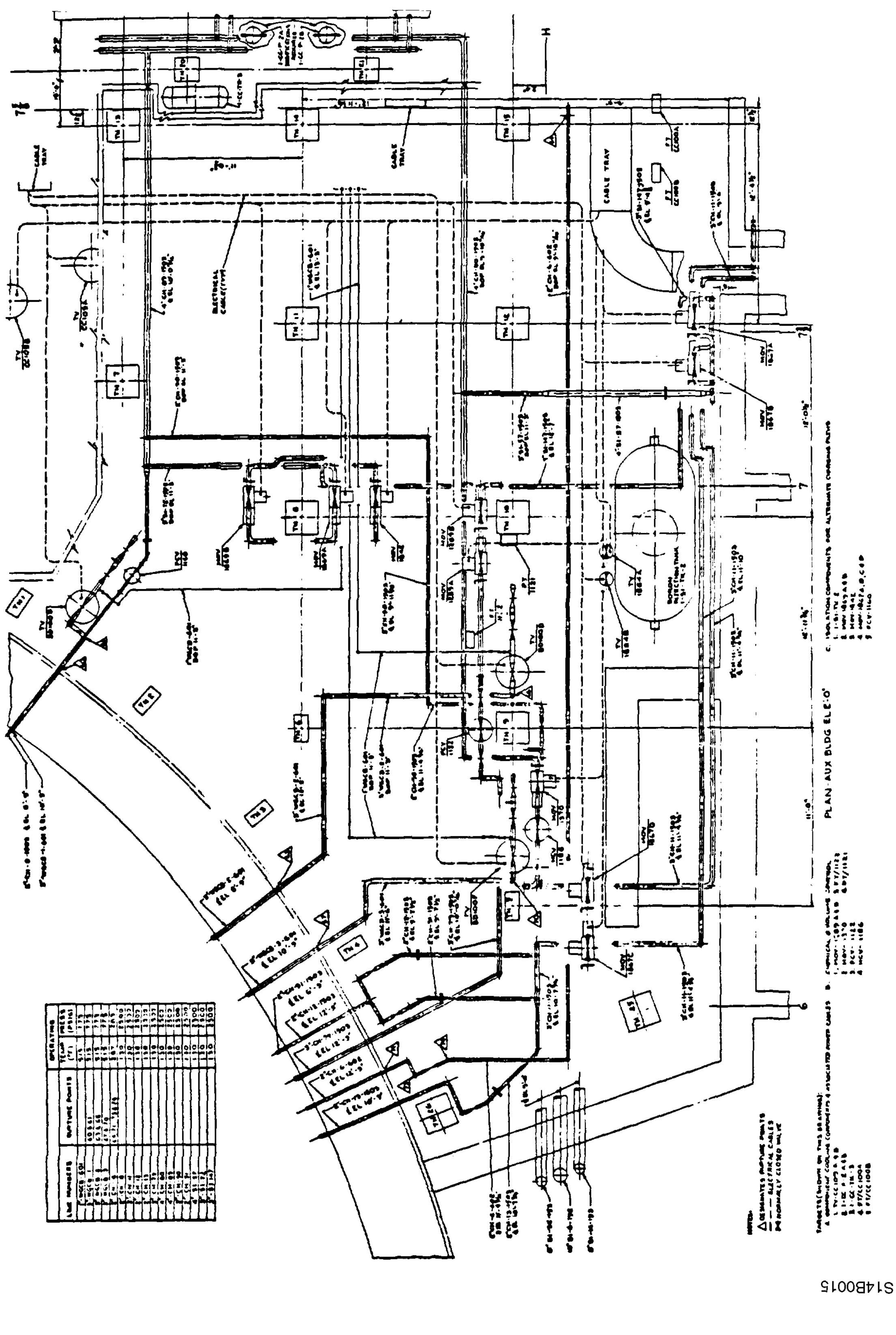


Figure 14B-13
AUXILIARY BUILDING SOURCES AND TARGETS-UNIT 1 SHEET 3



S14B0015

Figure 14B-14
AUXILIARY BUILDING SOURCES AND TARGETS SHEET 4

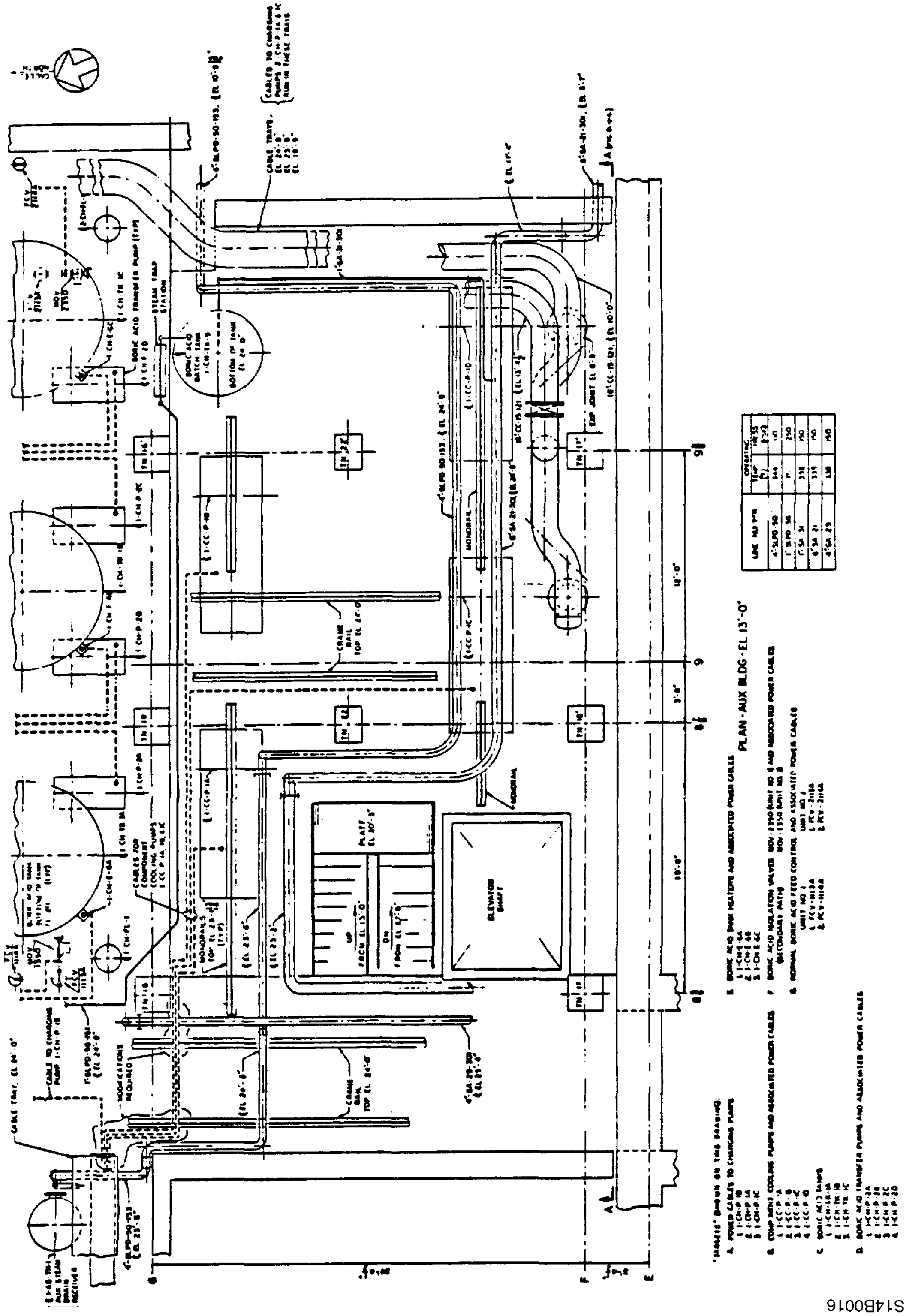
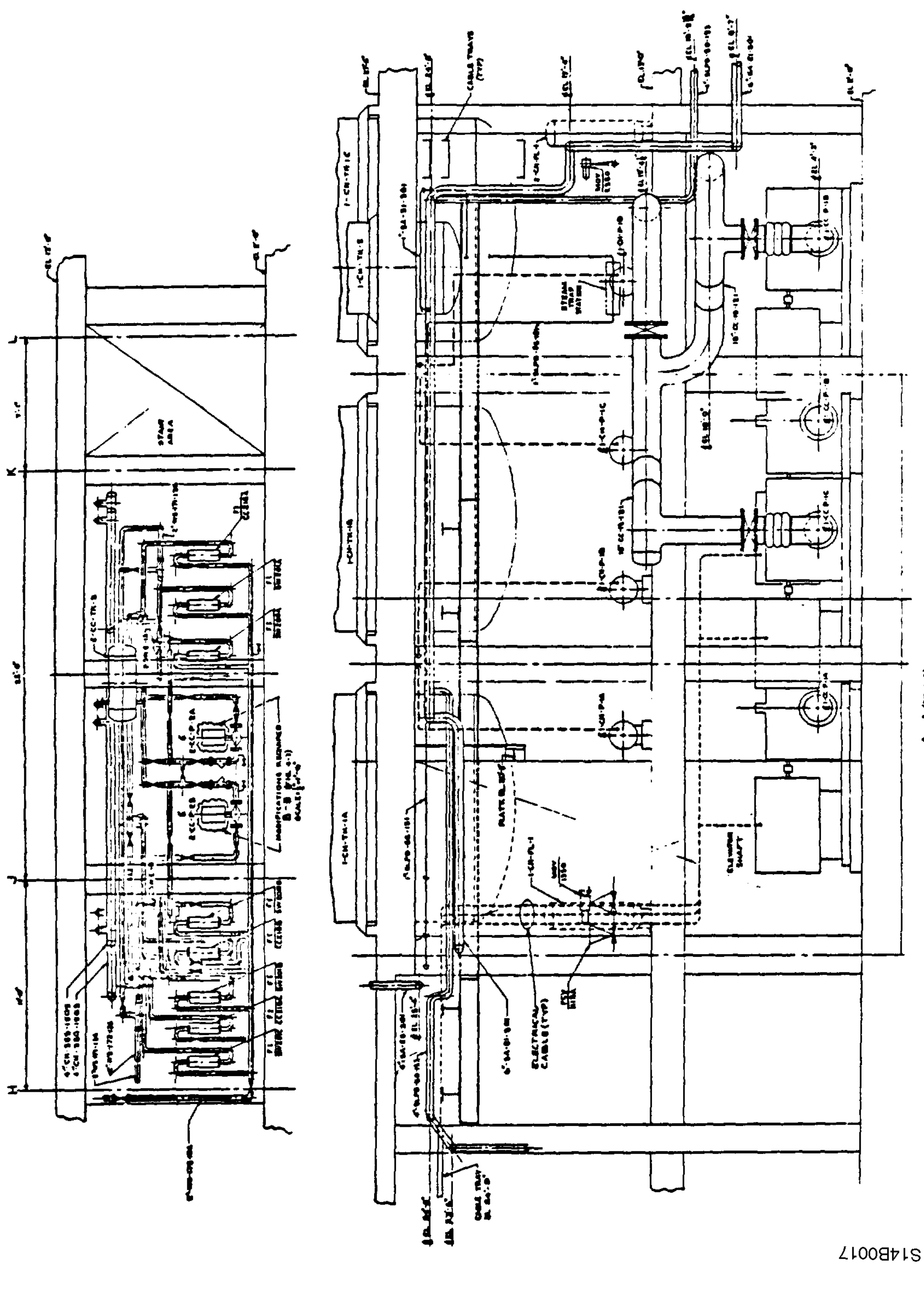


Figure 14B-15
AUXILIARY BUILDING SOURCES AND TARGETS SHEET 5A



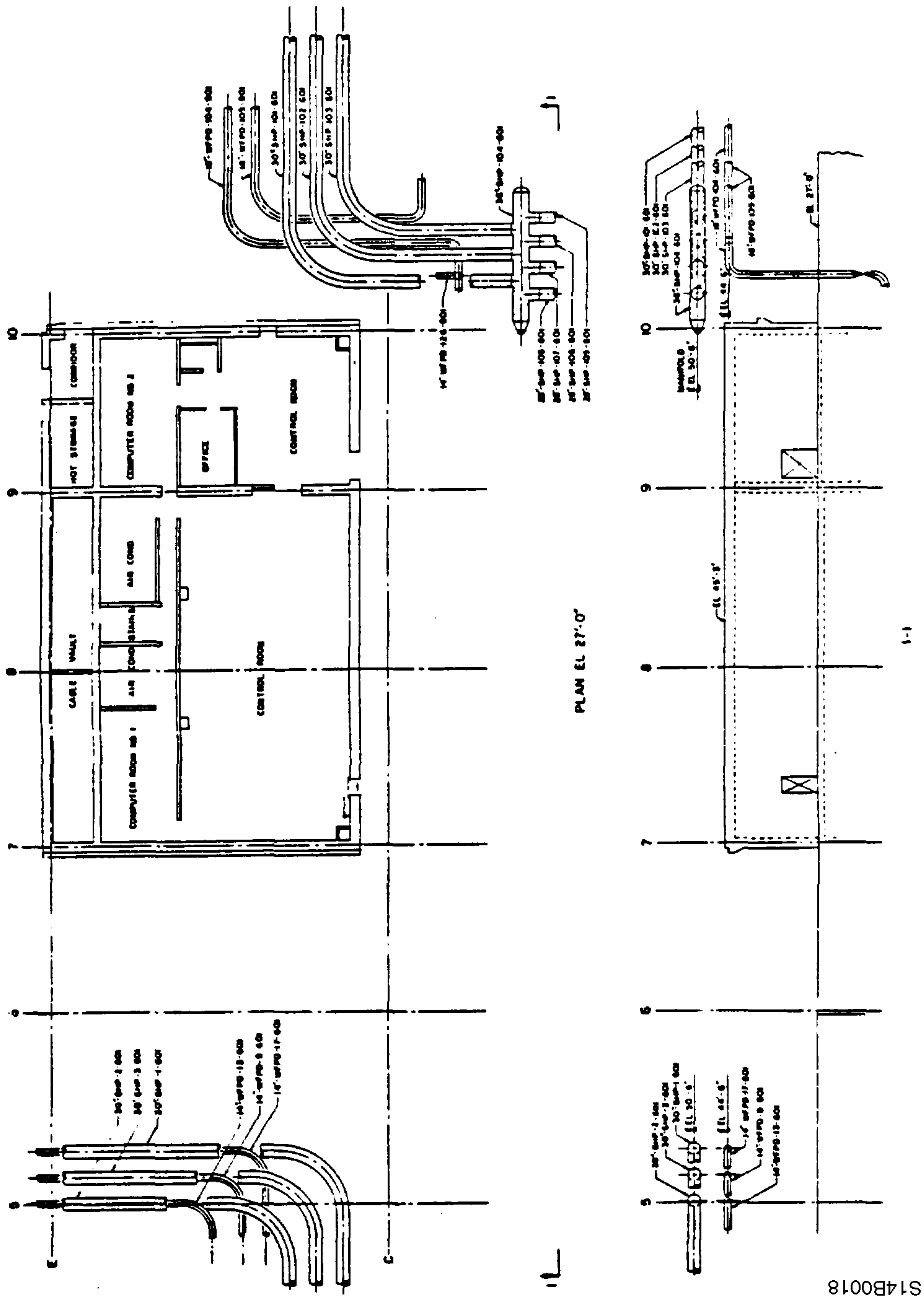


Figure 14B-16
CONTROL ROOM IN RELATION MAIN STEAM AND FEEDWATER LINE

Figure 14B-17
EXCLUDED AREAS

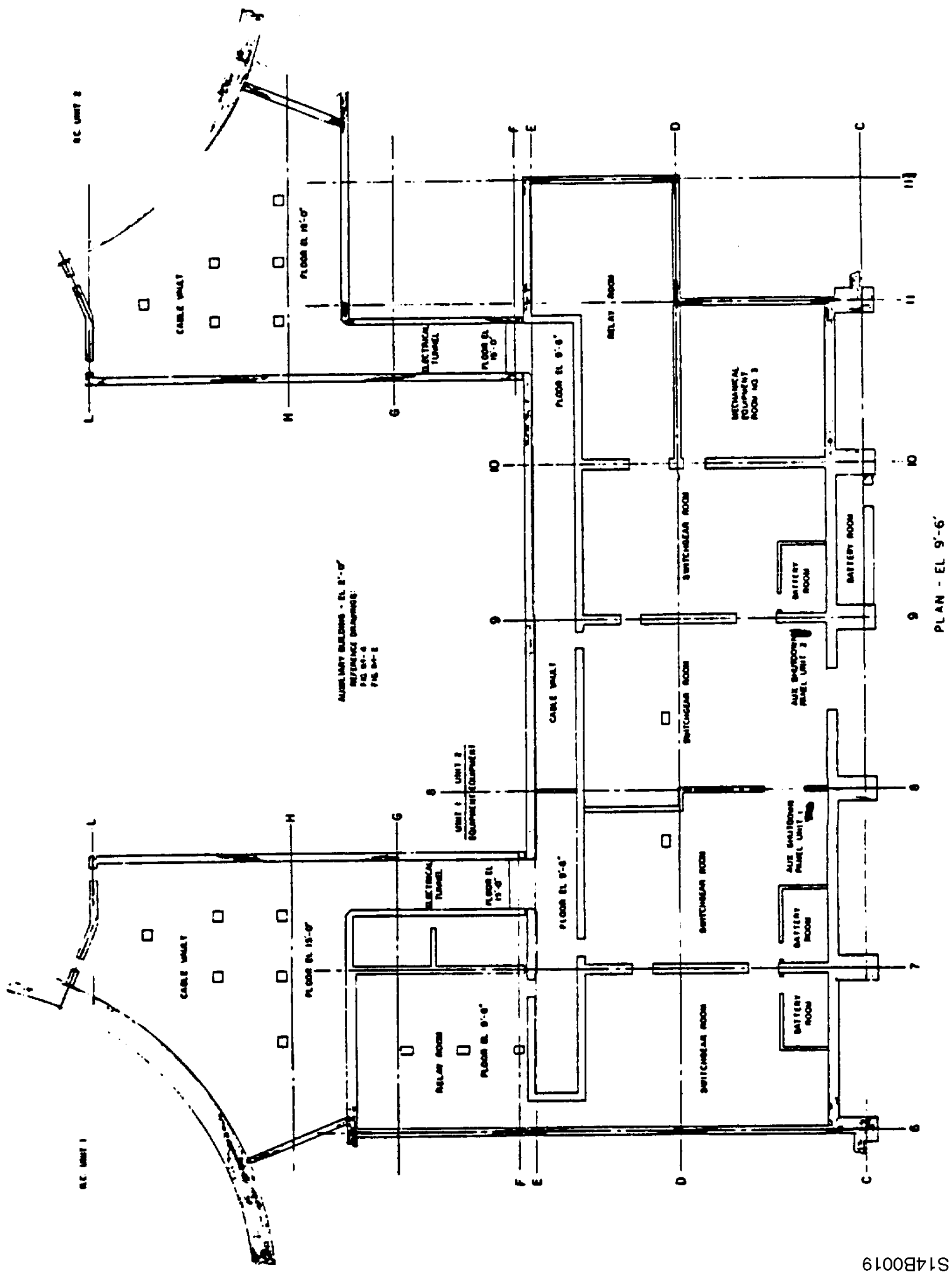


Figure 14B-18
PRESSURE BUILDUP IN MAIN STEAM VALVE HOUSE

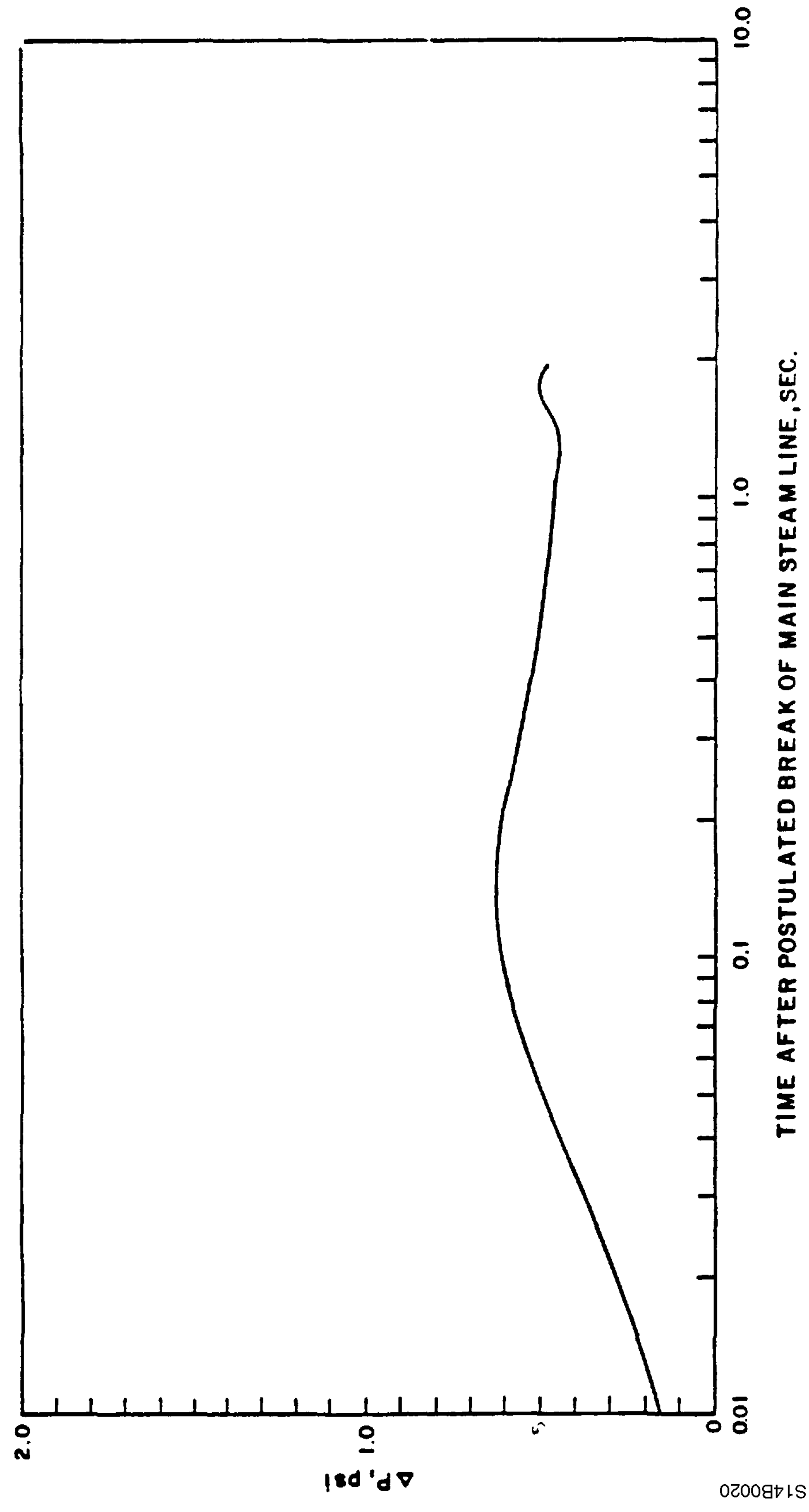
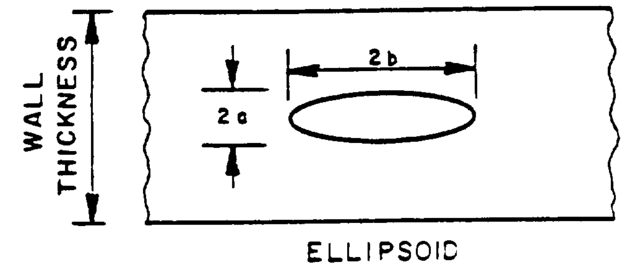


Figure 14B-19
CRACK AND FLAW GEOMETRIES

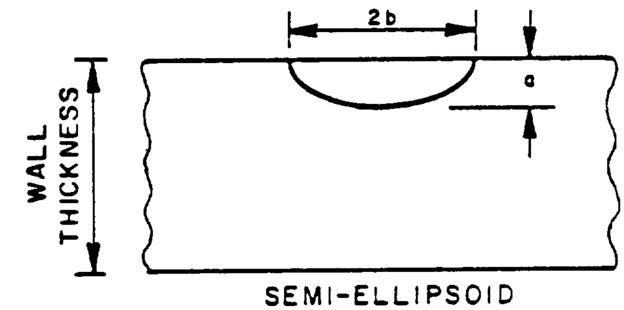
PART A

INTERNAL FLAWS



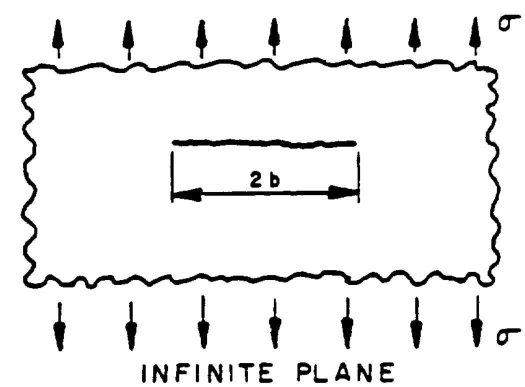
PART B

SURFACE FLAWS



PART C

AXIAL THROUGH WALL CRACKS



S14B0021

Figure 14B-20
FLOW DIAGRAM CROSS-CONNECTS FOR AUXILIARY FEED

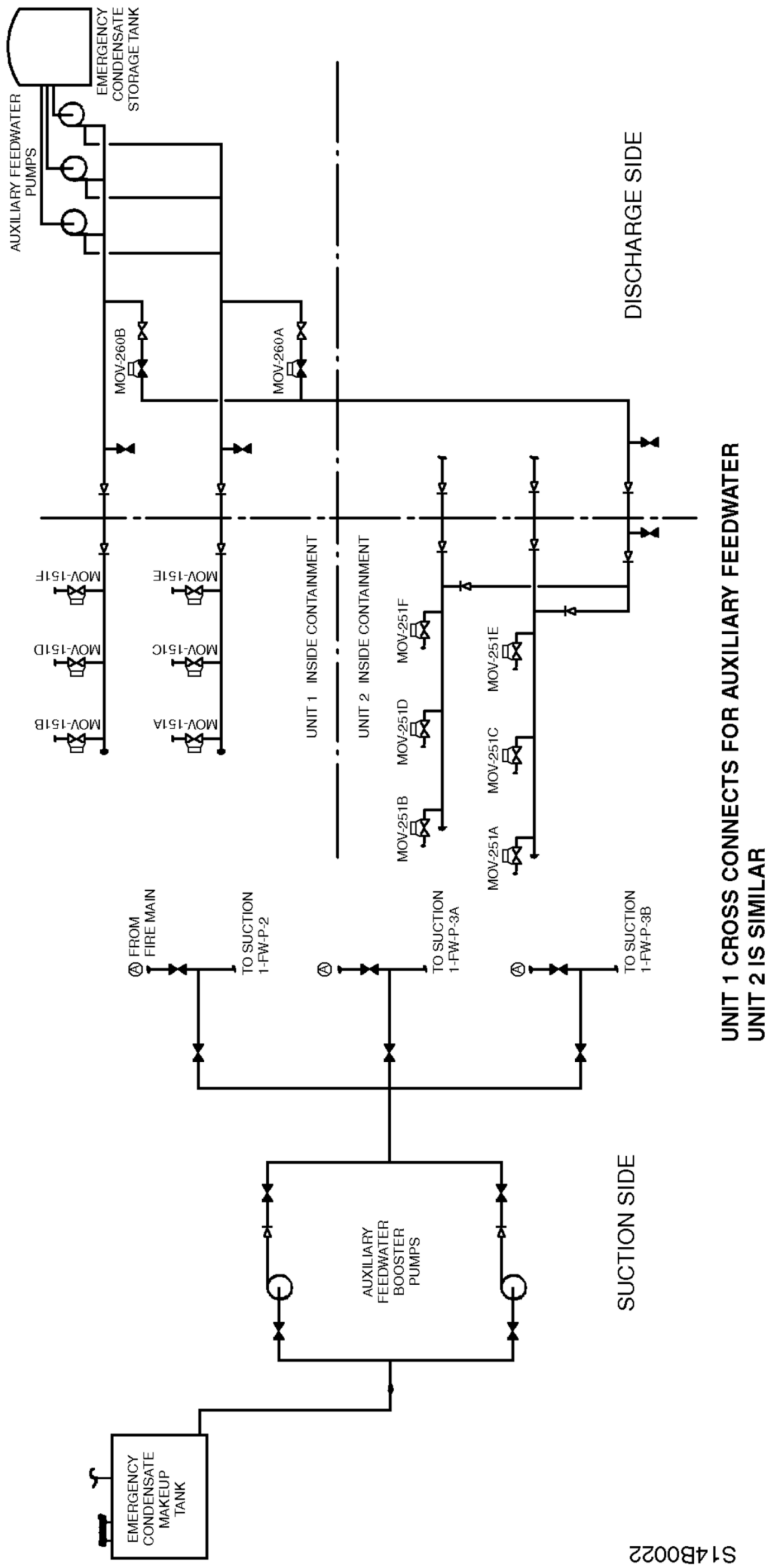
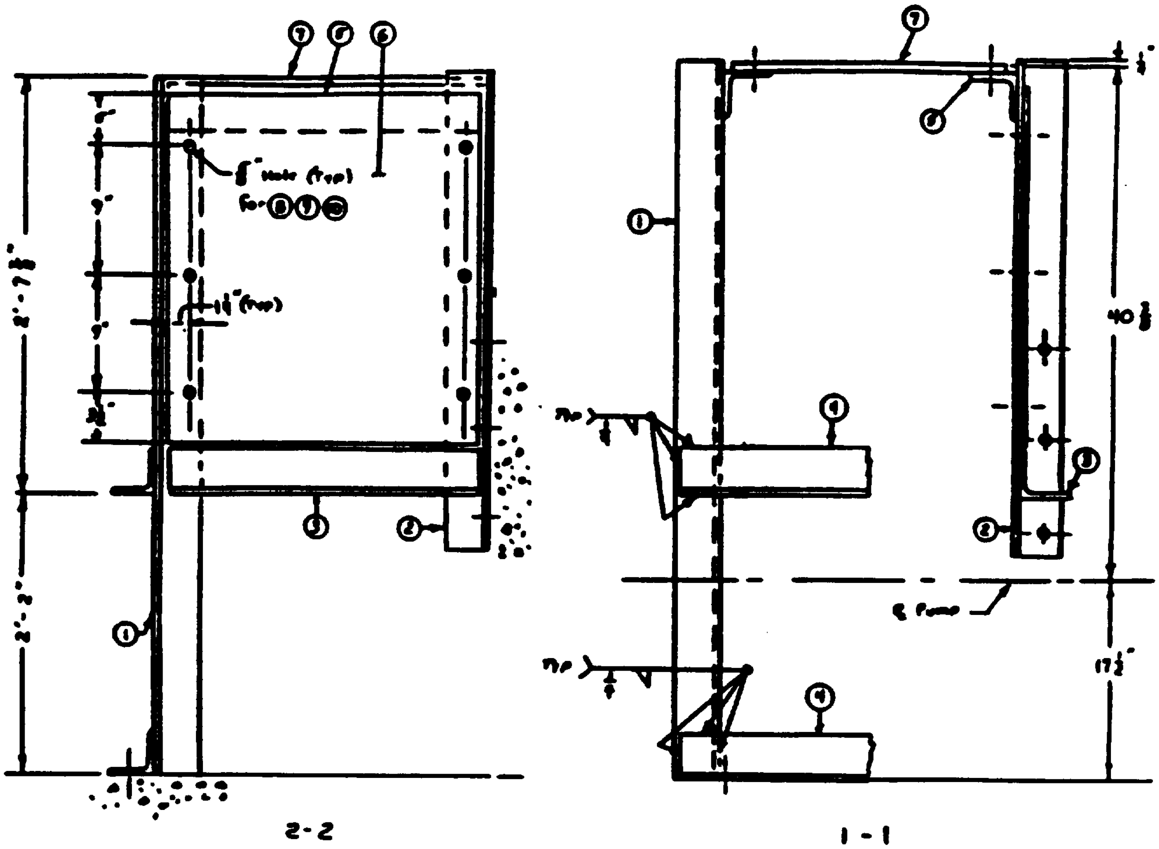
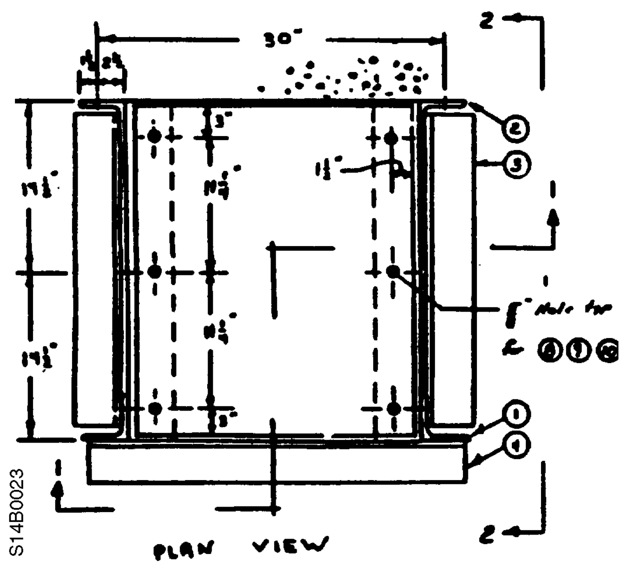


Figure 14B-21
BILL OF MATERIALS; JET IMPINGEMENT SHIELD





BILL OF MATERIALS

JET IMPINGEMENT SHIELD

Item	Quanti	Description	Material Spec.
1	2	L 4 x 4 x 3/8 4'-9 7/8" LG	A36
2	2	L 4 x 4 x 3/8 3'-1 5/8" LG	A36
3	2	L 4 x 4 x 3/8 2'-2 1/2" LG	A36
4	2	L 4 x 4 x 3/8 2'-7" LG	A36
5	2	L 4 x 4 x 3/8 2'-3" LG	A36
6	2	PL 3/8 x 2'-2 1/2" x 2'-2 1/2"	A36
7	1	PL 3/8 x 1'-11" x 2'-4 1/2"	A36
8	18	1/2" DIA BOLTS 2" LG	A325
9	18	1/2" DIA NUTS	A194
10	18	1/2" DIA WASHERS	

Surry Power Station
Updated Final Safety Analysis Report

Chapter 15

Intentionally Blank

Chapter 15: Structures and Construction
Table of Contents

Chapter 15: Structures and Construction
Table of Contents (continued)

Chapter 15: Structures and Construction
Table of Contents (continued)

Chapter 15: Structures and Construction
Table of Contents (continued)

Chapter 15: Structures and Construction

List of Tables

Chapter 15: Structures and Construction

List of Figures

Chapter 15: Structures and Construction

List of Figures (continued)

Intentionally Blank

CHAPTER 15 STRUCTURES AND CONSTRUCTION

15.1 STRUCTURES AND MACHINERY ARRANGEMENT

The site arrangement, plot plan, and the general arrangement of equipment within the principal Class I structures are shown on the Figures and Reference Drawings listed in the following tabulation:

Item	Reference Drawing
Site Plan	Figure 15.1-1
Plot Plan	Figure 15.1-2 and Reference Drawing 1
Containment Structure and Containment Auxiliary Structures	Reference Drawings 2 through 8
Auxiliary Building	Reference Drawings 9, 10, 11, & 12
Fuel Building	Reference Drawings 13 & 14
Control Area	Reference Drawing 15

15.1 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FY-1D	Plot Plan
2.	11448-FM-1A	Machine Location: Reactor Containment, Elevation 47'- 4"
3.	11448-FM-1B	Machine Location: Reactor Containment, Elevation 18'- 4"
4.	11448-FM-1C	Machine Location: Reactor Containment, Elevation 3'- 6"
5.	11448-FM-1D	Machine Location: Reactor Containment, Elevation 27'- 7"
6.	11448-FM-1E	Machine Location: Reactor Containment; Sections “A-A”, “E-E”, & “Z-Z”
7.	11448-FM-1F	Machine Location: Reactor Containment; Sections “B-B”, “X-X”, & “Y-Y”
8.	11448-FM-1G	Machine Location: Reactor Containment, Sections “C-C” & “D-D”
9.	11448-FM-5A	Arrangement: Auxiliary Building
10.	11448-FM-5B	Arrangement: Auxiliary Building, Unit 1
11.	11448-FM-5C	Arrangement: Auxiliary Building
12.	11448-FM-5D	Arrangement: Auxiliary Building
13.	11448-FM-9A	Arrangement: Fuel Building, Sheet 1
14.	11448-FM-9B	Arrangement: Fuel Building, Sheet 2, Unit 1
15.	11448-FA-1E	Control and Relay Room Service Building

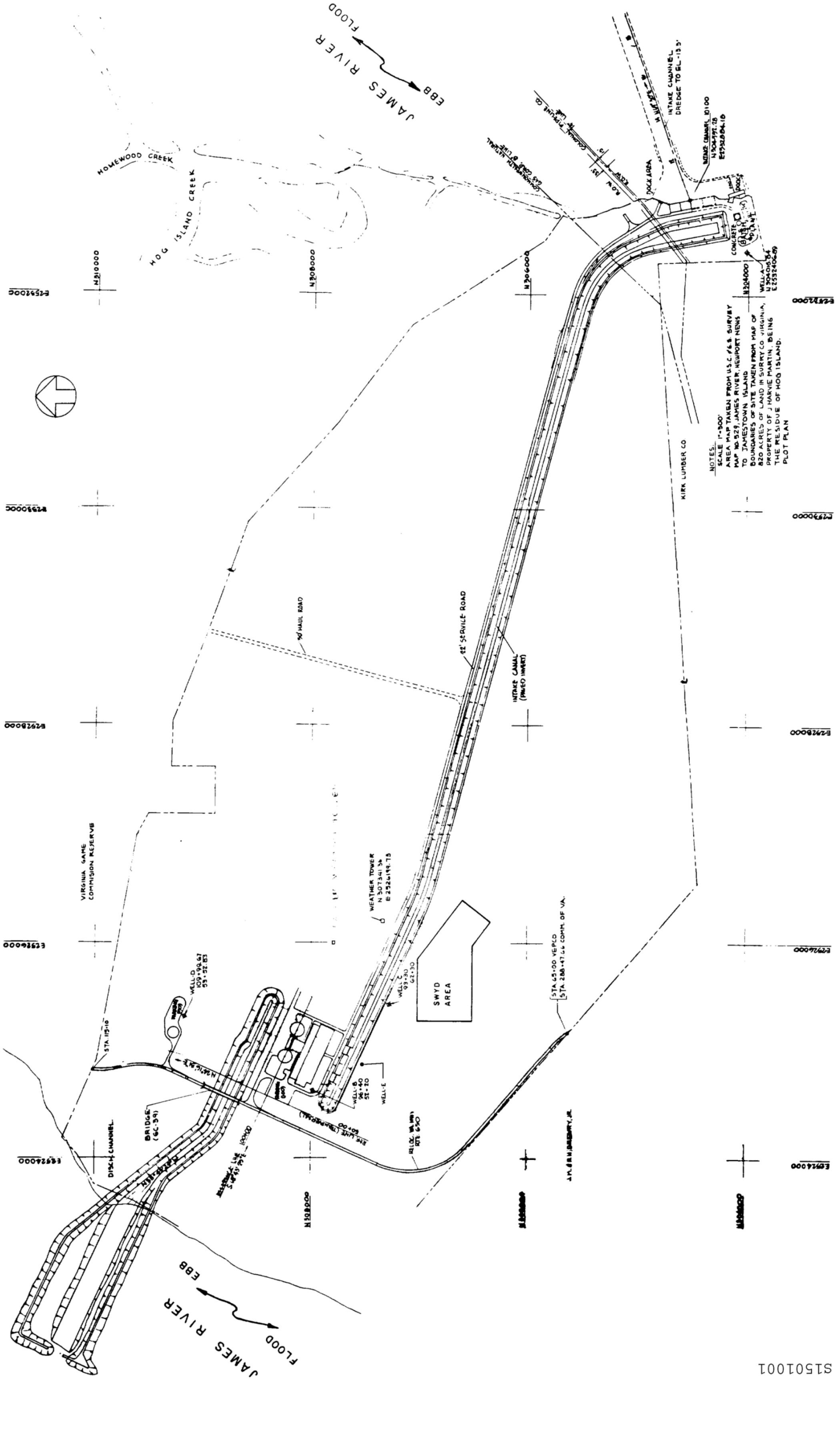


Figure 15.1-1
SITE PLAN

Withhold under 10 CFR 2.390 (d) (1)

[redacted]

15.2 STRUCTURAL DESIGN CRITERIA

15.2.1 General

The structures, systems, and components of the Surry Power Station, Units No. 1 and No. 2, are classified into groupings requiring seismic, tornado or conventional design. The effects of the Power Uprating to a core power of 2546 MWt on pipe stress and supports were reviewed for the systems listed below. The review determined that the existing piping and support configuration is adequate to withstand the increase in pressure and temperature associated with the Power Uprating.

Systems: Main Steam

Condensate

Extraction System

H. P. Heater Drain

L. P. Heater Drains

Reactor Coolant

Class I design encompasses those structures, systems or components of reactor facilities that are essential to the prevention of accidents that could affect the public health and safety, or to the mitigation of their consequences.

Structures, systems, and components are designed, fabricated, and constructed to performance standards that will enable the facility to withstand, without loss of capability to protect the public, the additional forces that might be imposed by:

1. The operating-basis earthquake and the design-basis earthquake.
2. Tornados and other local site effects including flooding conditions, winds, and ice. Radiation levels that constitute a hazard to the public are defined in 10 CFR 50.67.

A Class I structure is designed for resistance to seismic loadings in accordance with Section 15.2.4 and for tornados, where applicable, in accordance with Section 15.2.3. There are some structures, systems, or components whose loss or failure by earthquake will not affect the public health or safety and will permit safe station shutdown, although their loss could interrupt power generation. These structures, systems, or components are not designed for specific seismic or tornado loadings.

Structures not designed for seismic or tornado loadings are designed according to *Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings* (AISC-1963), and *Building Code Requirements for Reinforced Concrete* (ACI 318-63, Part IVA - *Working Stress Design*).

These structures are designed for dead, live, and normal wind loads using allowable stress levels given in the above codes.

Some structures, systems and components of the station are necessary for a safe and orderly shutdown during a tornado. These structures are designed for tornado loadings, and systems and components are protected by tornado-resistant structures.

A list of the structures, systems, and components designed to satisfy seismic and/or tornado criteria is given in Table 15.2-1.

15.2.2 Normal Wind Loading

All structures were designed to withstand the following wind loads applied to the projected area of all surfaces:

Elevation 26 ft. 6 in. to Elevation 56 ft. 6 in., 30 lb/ft^2

Elevation 57 ft. 6 in. to Elevation 75 ft. 6 in., 35 lb/ft^2

Elevation 75 ft. 6 in. to Elevation 130 ft. 0 in., 45 lb/ft^2

Elevation 131 ft. 0 in. and above, 55 lb/ft^2

Roofs were designed for uplift using 1.25 times the wind load taken at the corresponding elevation of the roof.

Members subject to stresses produced by this wind load combined with live and dead loads were proportioned for stresses 33-1/3% greater than conventional working stresses, provided that the section thus required is not less than that required for the combination of dead and live loads computed without the one-third increase.

15.2.3 Tornado Criteria

Section 2.2 outlines the probability of a tornado occurring at the site. Although no structural damage is known to have resulted to a reinforced concrete building in a tornado (Reference 1), the structures and systems so indicated in Table 15.2-1 are designed to ensure safe shutdown of the reactor when subjected to tornado loadings. The Seismic Class I and Tornado Criterion “T” structures discussed in Sections Section 15.2.3 and Section 15.2.4, respectively, are primarily of reinforced-concrete construction. The principal components that transmit horizontal and vertical loads to the foundation are the reinforced-concrete roof and floor slabs, and both interior and exterior reinforced-concrete walls. Since these components act as diaphragms, tending to minimize stress concentrations that might otherwise occur (in a column, for example), and their thicknesses are usually controlled by requirements for biological shielding or tornado and interior missile protection, stresses and strains are generally not significant. For these reasons, calculated stresses and strains for selected principal structural components have been omitted from this report. In addition, test data and analytical studies, in accordance with Appendix C of

Reference 13, have confirmed that 2-foot thick, reinforced-concrete test specimens, with similar spans and steel reinforcement as those found in SPS Tornado Criterion “T” structures (Table Table 15.2-1), will not experience a ductility ratio, μ, in excess of applicable industry code allowable limits (i.e., $\mu \leq 10$), when subjected to tornado load effects, as described in SPS UFSAR, Section 15.2.3.

The tornado model used for design has the following characteristics:

Rotational velocity	300 mph
Translation velocity	60 mph
Pressure drop	3 psi in 3 sec
Overall diameter	1200 ft
Radius of maximum winds	200 ft

Applicable structures are designed to resist a maximum wind velocity associated with a tornado of 360 mph, which is obtained by adding the rotational and translational velocities. Structures and systems are checked for tornado pressure loading, vacuum loading, and the combination of these two.

The tornado wind velocity is converted to an equivalent pressure, which is applied to the structures uniformly using the formula:

$$P = 0.00256\ V^2$$

where:

P = equivalent pressure, lb/ft^2

V = wind velocity, mph

This pressure is multiplied by applicable shape factors and drag coefficients as given in ASCE Paper No. 3269 by Thomas W. Singell (Reference 2), and applied to the silhouette of the structure.

A reduction of the full negative pressure differential is made when venting of the structures is provided. The amount of the reduction is a function of the venting area provided.

Tornado wind loads are combined with other loads as described in Section 15.5.1.2. Tornado and earthquake loads are not considered to act simultaneously. A uniform wind velocity and a nonuniform atmospheric pressure gradient is incorporated in the design of the containment structure.

Structural design criteria for tornado loading for the containment structure are given in Table 15.5-1 and Section 15.5.1.5.

It is assumed that a tornado could generate either of the following potential missiles:

1. Missile equivalent to a wooden utility pole 40 feet long, 12-inch diameter, weighing 50 lb/ft^3 and traveling in a vertical or horizontal direction at 150 mph.
2. Missile equivalent to a 1-ton automobile traveling at 150 mph.

The design assumes maximum wind forces and partial vacuum to occur simultaneously with the impact of either of the missiles singly. Allowable stresses do not exceed 90% of the certified minimum yield strength of the steel, the capacity reduction factor given in Section 15.5.1.2 times the certified minimum yield strength of the reinforcing steel, and 75% of the ultimate strength of the concrete. The allowable stress limits of 0.9 Fy (steel superstructures) and 0.9 fy and 0.75 f'c (reinforced concrete structures) apply to stresses from the overall structural response due to tornado load effects. These stresses are located away from the tornado missile impact zone and outside any yield-line patterns that may develop during the tornado missile impact.

It is noted that the physical configuration of certain plant components does not provide complete physical protection against tornado-generated missiles. The vulnerable surface area for each component was assessed probabilistically using the Tornado Missile Risk Evaluator Methodology (Reference 12) and it was determined that the risk to the plant is acceptably low, such that the additional missile protection need not be provided. Refer to Table 15.2-1 for identification of these components.

The U.S. NRC approval of the LAR 21-330 (References 14 & 15) demonstrates that the Surry Power Station (SPS) Turbine Building (TB) is a tornado-resistant structure, evaluated under a different methodology and acceptance criteria than other Tornado Criterion "T" structures at SPS, and is therefore classified as a Tornado Criterion "T+" structure in Table 15.2-1. The following bullet items distinguish the tornado evaluation methodology and acceptance criteria of the Tornado Criterion "T+" SPS TB structure, from other Tornado Criterion "T" structures at SPS.

- A nonlinear, static, finite element analysis methodology and associated acceptance criteria demonstrates that the TB is a tornado-resistant structure, which provides protection for safe shutdown and non-isolable water source components located in the basement of the TB during a tornado. Material properties are based on a true-stress, true-strain curve for carbon steel, which was developed based on the method provided in Section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code and using the design basis ASTM A36 material strength and properties. Column stability is based on a 1% maximum drift ratio from ASCE 7-10. The evaluation demonstrates that partial building collapse of the TB, consisting of the failure of the steel roof trusses, is expected during a tornado. The operating and mezzanine decks will remain stable and the TB overhead cranes, their supporting crane rails and steel columns, will not fall during a tornado. The stable operating and mezzanine decks of the TB will provide tornado protection for safe shutdown and non-isolable water source components located below in the basement of the TB. Additionally, partial building collapse of the TB structure during a tornado will not damage any adjacent Tornado Criterion 'T' structure and protected components housed within.

- The maximum tornado wind speed for the TB is established as 250-mph, which is the sum of a 208-mph rotational component and a 42-mph translational component.
- Only local effects of tornado missiles (i.e., penetration) need to be considered for the design of the TB and the 2-foot thick, reinforced concrete slabs at the mezzanine deck elevation, which provide physical tornado missile protection for safe shutdown components located directly below.
- For other safe shutdown and non-isolable water source components located in the basement of the TB, where physical tornado missile protection cannot be provided, adequate tornado missile protection is demonstrated via the Tornado Missile Risk Evaluator (TMRE) methodology and designated by the Tornado Criterion *"P""* protection classification in SPS UFSAR, Table 15.2-1.
- Partial differential pressures will not develop during a tornado in a vented structure such as the TB.
- In accordance with ACI 318-71, the allowable compressive stress limit for the reinforced concrete portions of the SPS TB structure shall not exceed $0.85f'_c$. This concrete compressive stress limit applies to the overall (i.e., global) structural response due to the tornado wind effects.

15.2.4 Seismic Design

Class I structures, systems, and components designed to resist seismic forces are listed in Table 15.2-1. The design is based on two separate seismic criteria: the operating-basis earthquake (OBE) and the design-basis earthquake (DBE), as described in Section 2.5.

The seismic analysis of Class I structures, such as the containment structure, auxiliary building, fuel building, service building (including the control room), and safeguard areas, was based on the modal analysis response spectra technique. Major equipment-supporting structures, such as steam generator supports, reactor coolant pump supports, and pressurizer supports, were treated in an identical manner. Acceleration response spectra for the OBE and DBE are given on Figures 2.5-5 and 2.5-6.

Seismic loading includes the horizontal or vertical responses acceleration or combinations of both where the effects, as measured by the separate acceleration components, of horizontal and vertical accelerations are combined to produce maximum stress intensities, taking into account any potential adverse effect due to phase of the separate accelerations.

Damping factors for the structures, systems, and components are given in Table 15.2-2.

The design of the containment structures is based on ultimate strength design and loading factors as described in Section 15.5.1.2. Maximum allowable stress levels for both the operating-basis earthquake and the design-basis earthquake are based on proportions of the minimum yield strength.

For other Class I structures, the operating-basis earthquake loading is combined with dead, live, and other static loads. Normal wind or tornado loadings are not assumed to occur simultaneously with the earthquake loading. Members are proportioned for stresses 33-1/3% greater than conventional working stresses, provided that the section thus required is not less than that required for the combination of dead and live loads computed without the one-third increase. Allowable soil-bearing values are increased one-third.

For Class I structures other than the containment structure, the design basis earthquake is combined with static loads using loading combinations given in Table 15.5-1. For these structures under the design-basis earthquake loading, the allowable stresses do not exceed 90% of the certified minimum yield strength for structural steel, the capacity reduction factor, given in Section 15.5.1.2, times the certified minimum yield strength for reinforcing steel, and the capacity reduction factor times the specified strength for concrete. Allowable soil bearing values are increased by one-half.

To allow for unimpeded relative motions between structures, a rattlespace is provided between the:

1. Containment structures and the auxiliary building.
2. Containment structures and the fuel building.
3. Containment structures and the containment auxiliary structures around the periphery of each containment.
4. Fuel building and auxiliary building.
5. Auxiliary building and control area.

In general, the periphery of the rattlespace between buildings is arranged to prevent material entering the space, with the inner areas left as a void.

Maximum relative motions between adjoining structures are included in the stress analyses of all piping that extends from one building to another.

Type “A” sand, as described in Section 2.4.3.3, was removed from under the fuel building, auxiliary building, and control area and replaced by a dense graded granular fill material as described in Section 2.4.5.1.

The analytical procedure used for the nuclear steam supply system is described by Section 15A.3 of Appendix 15A.

The reactor protection system, engineered safety feature (ESF) circuits, and the emergency power system are designed so that they will not lose the capability to shut the plant down and maintain it in a safe shutdown condition under operating-basis earthquake or design-basis earthquake conditions. For the design-basis earthquake, permanent deformation of the equipment is allowable, provided that the capability to perform its function is maintained.

Typical protection system equipment is subjected to type tests under simulated seismic accelerations to demonstrate its ability to perform its functions. Type testing was performed using conservatively large accelerations and applicable frequencies. Analyses were done for structures that were not done for the reactor protection system equipment. However, the peak accelerations and frequencies were checked against those derived by structural analyses of operational and design-basis earthquake loadings.

A Westinghouse topical report, WCAP-7397-L, provides the seismic evaluation of safety-related equipment. The type tests covered by this report are applicable to the Surry Power Station, with the exception of the process control equipment, which is covered in a supplement to WCAP-7397-L.

The emergency switchgear has been tested under seismic conditions, and manufacturers' test data are available. The emergency generator and control panels are identical with those used in locomotives, and have been tested under severe conditions, but no seismic tests have been made.

The control board was designed to withstand earthquake conditions, and an analysis was performed to verify the adequacy of the seismic design, but tests were not performed.

The emergency batteries are supported on rigid reinforced concrete pedestals firmly anchored to the floor. Steel retaining members integral with the pedestals prevent the batteries from being dislodged under seismic excitation.

15.2.5 Hydrostatic Loadings

Finish ground grade at the station is at Elevation 26 ft. 6 in. Natural ground water level is at approximately Elevation 4 ft. 0 in.

The exterior wall of the containment structure extends approximately 66 feet below the finished ground level. Water-resistant membrane protection for this structure is defined in Sections 15.5.1.9 and 15.5.1.10. External pumps for reducing the hydrostatic head on the containment structure are described in Section 15.5.1.3. This latter section also discusses the effect of the buoyant pressure on the containment structure.

Exterior surfaces of walls of other Class I structures with floor levels below Elevation 26 ft. 6 in. are covered with a mopped-on bitumastic coating to establish a water-resistant membrane.

The roofs of safety-related structures and select nonsafety-related structures with the potential to impact structures, systems, or components important to safety are evaluated to withstand hydrostatic surcharge loading associated with a Beyond Design Basis (BDB) Local Intense Precipitation (LIP) rainfall event. Roof parapets of the Turbine Building, Service Building, and Condensate Polishing Building feature cutouts to passively limit the hydrostatic surcharge loading induced by the postulated BDB event.

Building penetrations susceptible to flooding from a BDB LIP rainfall event are equipped with flood seals in locations which protect structures, systems, or components important to safety.

15.2 REFERENCES

1. V. C. Gilberton and E. E. Mageanu, *Tornadoes*, *AIA Technical Reference Guide*, TRG 13-2, U. S. Weather Bureau.
2. T. W. Singell, *Wind Forces on Structures: Forces on Enclosed Structures*, *Journal of the Structural Division of the ASCE*, July 1958.
3. Deleted.
4. Letter, NRC to Vepco, Serial #85-885, dated December 4, 1985
5. ASME Boiler and Pressure Vessel Code, Section III, Division I, Code Case N-411, *Alternative Damping Values for Seismic Analysis of Piping Sections,* American Society of Mechanical Engineers, 345 E. 47th Street, New York, NY 10017, dated September 17, 1984.
6. NRC Bulletin No. 88-11: *Pressurizer Surge Line Thermal Stratification,* USNRC, December 20, 1988.
7. Virginia Power Letters Serial Nos. 89-006A dated May 3, 1989 and 89-006B dated November 13, 1989 to United States Nuclear Regulatory Commission.
8. *Revised report on the Reanalysis of Safety-Related Piping Systems - Surry Power Station, Unit 1*, August 1979, by Stone & Webster Engineering Corporation.
9. *Report on the I.E. Bulletin 79-14, Analysis for As-Built Safety-Related Piping Systems - Surry Power Station - Unit 2,* July 1981, by Ebasco Services, Inc.
10. *Report on the Reanalysis of Safety-Related Piping Systems - Surry Power Station - Unit 2,* Rev. 1, April 1980, by Ebasco Services, Inc.
11. Mitsubishi Heavy Industries, LTD., Design Report DG KCS-03-0008, *Dominion Generation, Surry Power Station Unit 2, Control Rod Drive Mechanism Design Report,* Rev. 3.
12. NEI 17-02, Rev. 1B, *Tornado Missile Risk Evaluator (TMRE)*, September 2018, as implemented and approved at Shearon Harris Nuclear Power Plant (ML18347A385).

13. SWECO 7703, Missile-Barrier Interaction - A Topical Report, Stone & Webster Engineering Corporation, Boston, MA, September 1977

14. Letter from Virginia Electric and Power Company to the U.S. NRC, dates April 14, 2002 (Serial No. 21-330), *Virginia Electric sand Power Company, Surry Power Station Units 1 and 2, License Amendment Request for NRC Approval of Methodology Change and Reclassification of the Turbine Building as a Tornado Resistant Structure*: (ML22104A125), supplemented by Letters ML22131A326, ML22339A137, ML23025A125, and ML23082A136.

15. Letter from the U.S. NRC to Virginia Electric and Power Company, dates April 25, 2023, *Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendment Nos. 310 and 310 Regarding Turbine Building Tornado Classification (EPID L-2022-LLA-0056)* (ML23199A065).

Table 15.2-1

STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Structures				
Reactor containment			SW	
Reinforced-concrete substructure	I	P		
Reinforced-concrete superstructure	I	T		
Reinforced concrete interior shields and walls	I	NA		
Steel plate liner	I	P		P for containment integrity
Piping, duct, and electrical penetrations and shield wall	I	P		P for shield wall and critical system penetrations only
Personnel access hatch	I	P		P for containment integrity
Equipment access hatch	I	P		P for containment integrity
Equipment hatch platform	I	T	SW	T for tornado winds only
Cable vault and cable tunnel	I	T	SW	
Pipe tunnel to containment from auxiliary building	I	T	SW	
Main steam valve house	I	T	SW	
Auxiliary steam generator feed pump cubicle	I	T	SW	
Cubicle for main steam and feedwater isolation valves	I	T	SW	
Containment spray pump house, below grade	I	T	SW	EL. +27.5’ and below
Recirculation spray and low-head safety injection pump cubicle and pipe tunnel	I	P	SW	
Safeguards ventilation room	I	NA	SW	

Table 15.2-1 (CONTINUED)

STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)

STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Structures (continued)				
Auxiliary building			SW	
Reinforced-concrete structure	I	T		
Steel superstructure	I	NA		
Vacuum equipment area	I	NA		
Fuel building			SW	
Reinforced-concrete structure	I	T		T for horizontal missile only
Steel superstructure	I	T		T for tornado winds only
Spent-fuel storage rack	I	P		P for horizontal missile only
Fuel-handling trolley support structure	I	T		Over spent-fuel pit only T for tornado winds only
Service building			SW	
Control room	I	T	SW	
Emergency switchgear and relay room	I	T	SW	
Battery rooms	I	T	SW	
Mechanical equipment room-3	I	T	SW	
(Air-conditioning equipment room)				For control room and relay room only
Mechanical equipment room-4	I	T		
Reactor trip breaker cubicle	I	T	SW	
Emergency diesel-generator rooms			SW	
Reinforced-concrete floor	I	T		
	I	T		

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Emergency diesel-generator rooms (continued)				
Walls, excluding louvers				
Roof slab	I	T		
Turbine building	NA	T+	SW	By design, building collapse will not damage any Class I structures and components during earthquake, or tornado-resistant structures and components during tornado (See NOTE 3)
Mechanical Equipment Room-5	I	T		
Low-level intake structure	I	T	SW	T for emergency service water cubicle pump only
(Circulating water pump intake structure)				
High-level intake structures	I	T	SW	T, no missile protection required
Seal pits	I	T	SW	T, no missile protection required
High-level intake canal	I	NA	SW	
Fire-pump house	I	T	SW	Engine-driven pump only
Fuel-oil transfer pump vault	I	T	SW	
Boron recovery tank dikes	I	T	SW	
Waste gas & boron recovery pump house	I	T	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems				
Reactor coolant system				
Steam generators	I	P	W	
Steam generator supports	I	P	SW	
Reactor coolant pumps[b]	I	P	W	
Reactor coolant pump supports	I	P	SW	
Pressurizer and pressurizer heaters	I	P	W	
Pressurizer support	I	P	SW	
Pressurizer relief tank	I	P	W	
Reactor vessel				
Reactor core support structure	I	P	W	
Reactor control rod guide structure	I	P	W	
Fuel assemblies	I	P	W	
Control rod and drive shaft assemblies	I	P	W	
Incore instrumentation thimbles	I	P	W	
Reactor vessel supports and neutron shield tank	I	P	SW	
Control rod drive mechanisms	I	P	W	
Reactor coolant piping, valves, and supports[b]	I	P	W	

a. HISTORICAL information, see Note 2.

b. All references to “piping and valves” include root valves connecting to non-Class I systems, and valve operators.

c. Pressurizer surge line was reanalyzed per NRC Bulletin 88-11, dated December 20, 1988.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Reactor coolant system (continued)				
Reactor coolant bypass piping, valves, and supports	I	P	W	
Pressurizer surge line	I	P	W, SW [c]	
Pressurizer spray lines, valves, and supports	I	P	SW	
Pressurizer safety and relief valves	I	P	W	
Safety injection system				
Accumulators and supports	I	NA	W	
Low-head safety injection pumps and piping	I	P	W	P for containment integrity
Boric acid injection tanks and piping	I	P	W	
Piping, valves, and supports	I	NA	SW	Except drain/sample lines
Containment spray system				
Refueling water storage tank	I	NA	SW	
Containment spray pumps	I	NA	SW	
Piping, valves, and supports	I	NA	SW	Except recirculation lines

a. HISTORICAL information, see Note 2.

b. All references to “piping and valves” include root valves connecting to non-Class I systems, and valve operators.

c. Pressurizer surge line was reanalyzed per NRC Bulletin 88-11, dated December 20, 1988.

Systems (continued)

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Recirculation spray systems				
Recirculation spray pumps and piping	I	P	SW	P for containment integrity
Recirculation spray heat exchangers	I	NA	SW	
Reactor containment sump and screens	I	NA	SW	
Piping, valves, and supports	I	NA	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Containment vacuum system				
Process vent	I	NA	SW	
Vacuum pump piping, valves, and supports	I	NA	SW	
Chemical and volume control system				
Boric acid storage tanks	I	NA	W	
Boric acid transfer pumps	I	P	W	
Boric acid blender	I	P	W	
Charging/safety injection pumps	I	P	W	
Regenerative heat exchanger	I	P	W	
Nonregenerative heat exchanger	I	P	W	
Mixed-bed demineralizers	I	P	W	
Reactor coolant filter	I	P	W	
Volume control tank	I	P	W	
Seal-water heat exchanger	I	P	W	
Seal-water filter	I	P	W	
Excess letdown heat exchanger	I	P	W	
Piping, valves, and supports				
Boric acid piping	I	P	SW	
Feed and bleed piping	I	P*	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Chemical and volume control system (continued)				
Piping, valves, and supports (continued)				
Hydrogen, nitrogen, and vent piping for volume control tank	I	P	SW	
Residual heat removal system				
Residual heat removal pumps	I	P	W	
Residual heat exchangers	I	P	W	
Piping, valves, and supports	I	P	SW	
Boron recovery system				
Gas stripper	I	P	SW	
Gas stripper overhead condenser	I	P	SW	
Primary drain tank	I	P	SW	
Primary drain tank vent chiller condenser	I	P	SW	
Overhead gas compressors	I	P	SW	
Gas stripper surge tank	I	P	SW	
Component cooling system				
Component cooling pumps	I	P	SW	
Component cooling water heat exchangers	I	P	SW	
Component cooling surge tank	I	P	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Component cooling system (continued)				
Piping, valves, and supports				
For residual heat exchangers	I	P*	SW	
For fuel pool coolers	I	P*	SW	P for horizontal missile only
RCP thermal barrier supply piping from the upstream check valves to the RCPs	I	P	SW	
Charging pump component cooling water system				
Charging pump component cooling water pumps	I	P	SW	
Charging pump mechanical seal coolers	I	P	SW	
Charging pump seal cooling surge tank	I	P	SW	
Charging pump intermediate seal coolers	I	P	SW	
Piping, valves, and supports	I	P	SW	
Fuel pool cooling system				
Fuel pool pumps	I	P	SW	P for horizontal missile only
Fuel pool coolers	I	P*	SW	P for horizontal missile only
Piping, valves, and supports connecting above equipment to spent-fuel pool	I	P	SW	P for horizontal missile only

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Compressed air system				
Critical system interface components - local instrument air accumulators/bottled sources and associated piping, valves, and supports				
Interfacing systems:				
Reactor coolant system - Pressurizer PORVs	I	P		
Component cooling system - Containment isolation trip valves from the RHR HXs	I	P		
Main steam/feedwater system - Steam supply admission valves to the turbine driven auxiliary feedwater pump	I	P		
Ventilation vent system - Dampers - Fuel building filtered exhaust, containment air compressor cubicle exhaust, safeguards area normal exhaust, charging pump normal and filtered ventilation, and containment exhaust isolation	I	N/A		
Service water system				
Engine-driven emergency service water pumps	I	P*	SW	
Charging pump service water pumps	I	P	SW	
Charging pump lubricating oil coolers	I	P	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Service water system (continued)				
Service water piping, valves, and pipe supports for:				
Recirculation spray heat exchangers	I	NA	SW	
Component cooling heat exchangers	I	P*	SW	
Engine-driven emergency service water pump	I	P*	SW	
Emergency diesel-generator cooling	I	P	SW	
Control room air-conditioning equipment condensers	I	P*	SW	
Charging pump lube-oil coolers	I	P*	SW	
Diesel-oil tank for emergency service water pump	I	P*	SW	
Fire protection system				
Engine-driven fire pump	I	P	SW	
Diesel-oil tank (300 gallons)	I	P	SW	
Yard hydrant piping system	I	NA	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Fuel handling system				
Manipulator crane in containment	I	P	W	Crane will be parked and secured so no damage to reactor control rod drive mechanisms can occur during earthquake
Movable platform with hoist in fuel building	I	NA	SW	Platform will be parked and secured so no damage to fuel can occur during earthquake or tornado
Fuel-handling trolley in fuel building	I	NA	SW	Trolley will be parked and secured during tornado warning periods so no damage to spent fuel can occur
Fuel transfer tube with blind flange	I	P	SW	P for containment isolation
Fuel elevator in fuel building	I	NA	SW	
Ventilation system				
Ventilation equipment for safeguards ventilation room	I	NA	SW	
Ductwork from safeguards ventilation room to ventilation vent no. 2	I	NA	SW	
Ductwork for containment purge system penetrating containment between and including isolation butterfly valves	I	P	SW	P for containment isolation

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Ventilation system (continued)				
Air-conditioning equipment for main control room and relay room	I	P	SW	
Emergency main control and relay room ventilation	I	P	SW	
Ventilation vent no. 2	I	NA	SW	
Control rod drive ventilation fans	NA	P	SW	
Main steam system				
Steam piping from main steam lines to auxiliary steam generator feed pump turbine	I	P	SW	
Main steam piping from steam generators to and including main steam trip valve	I	P	SW	
Main steam piping, valves, and supports from trip valves to and including turbine stop valves	NA	NA	SW	Check was made that design-basis earthquake would not cause failure to function
Turbine steam bypass piping, valves, and supports to condenser	NA	NA	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Circulating water system				
Condenser	NA	NA	SW	Check was made that condenser water boxes will not fail during earthquake
Circulating water piping, valves, and supports from high-level intake canal to circulating water discharge tunnel to and including condenser intake butterfly valve; condenser discharge butterfly valve	I	P*	SW	P, underground
Circulating water discharge tunnel	I	P	SW	
Circulating water pump vacuum breaker	NA	NA	SW	No credible failure mode for passive vacuum breaker
Condensate and feedwater system				
Emergency condensate storage tank	I	P	SW	
Emergency condensate makeup tank	I	P	SW	
Auxiliary steam generator feed pumps	I	P*	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Condensate and feedwater system (continued)				
Piping, valves, and supports				
Emergency condensate storage tank to auxiliary steam generator feed pump	I	P	SW	
From auxiliary steam generator feed pumps to steam generator feed lines	I	P	SW	
Steam generator feed lines inside containment to and including first isolation check valve outside containment	I	P	SW	
Primary vent and drain system				
Primary drain cooler	I	P	W	
Piping, valves, and supports	I	P	SW	
Primary drain transfer tank	I	P	SW	
Secondary vent and drain system				
Steam generator blowdown piping, valves, and supports inside containment to and including first isolation trip valves	I	P	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Gaseous waste disposal system				
Waste gas decay tanks	I	P	SW	
Waste gas recombiner system	I	NA	SW	
Waste gas compressors	I	NA	SW	
Waste gas filter	I	NA	SW	
Process vent blowers	I	NA	SW	
Waste gas piping, valves, and supports from stripper to process vent	I	NA	SW	
Process radiation monitoring system				
Process vent particulate monitor	I	NA	SW	
Process vent gas monitor	I	NA	SW	
Spray recirculation heat exchanger service water monitors	I	NA	SW	
Area radiation monitoring system				
Main control room monitor	I	P	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Instrumentation and control				
All instrumentation and control to operate and monitor operation of critical system component shown above during MCA or controlled shutdown				
Systems include:				
Reactor protection (in part)	I	P	W	
Safeguards initiation	I	N/A	W/SW	
Containment isolation	I	P	W/SW	
Reactor control (in part)	I	P	W	Includes trip breakers
Steam generator water level control system	I	P	W	
Reactor makeup control	I	P	W	
Nuclear instrumentation (in part)	I	P	W	
Non-nuclear process instrumentation	I	P	W/SW	
Circulating water intake canal low level isolation system	I	P	N/A	
Electrical systems				
Emergency diesel-generators	I	P	SW	
Fuel-oil day tanks	I	P	SW	
Fuel-oil transfer pumps	I	P	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note
Systems (continued)				
Electrical systems (continued)				
Underground fuel-oil storage tanks	I	P	SW	
Fuel-oil piping, valves, and supports, emergency diesel-generators	I	P	SW	P for piping to protected generators
Station service batteries and chargers	I	P	SW	
Vital bus and inverters	I	P	SW	
Emergency station service transformers	I	P	SW	
Emergency station service switchgear	I	P	SW	
Control panel boards	I	P	SW	
Pressurizer heater control group only	I	P	SW	
Cable to critical components, instruments, and controls as shown above	I	P	SW	Cable passing through unprotected areas will be in rigid conduit
Miscellaneous				
Reactor containment crane	I	P	SW	
Piping	I	P	SW	

a. HISTORICAL information, see Note 2.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note

Legend

W - Westinghouse Electric Corporation.

SW - Stone & Webster Engineering Corporation.

I - Refers to Seismic Class I criteria. All Class I components and structures are designed to resist the operating-basis earthquake within allowable working stresses. A check has been made to determine that failure to function will not occur with a design-basis earthquake.

T - Refers to structures that will not fail during the design tornado.

T+ - Refers to the main structural steel members and reinforced concrete slabs of the operating and mezzanine decks of the Turbine Building structure, which will remain stable and not collapse during a tornado with a 250-mph maximum wind speed.

P - Refers to systems and components that will not fail during the design tornado since they are protected by tornado resistant structures or by being buried underground.

P* - Refers to systems and components that are not provided with complete physical protection from tornado-generated missiles, but have been evaluated using the Tornado Missile Risk Evaluator Methodology (Reference 12) and it has determined that the risk to the plant associated with the partially exposed SSC is sufficiently low such that complete physical protection from tornado-generated missiles need not be provided.

NA - Not applicable.

Table 15.2-1 (CONTINUED)
STRUCTURES, SYSTEMS, AND COMPONENTS DESIGNED FOR SEISMIC AND TORNADO CRITERIA

(Refer to the equipment classification list (Q-list) for a more comprehensive list of components. See Note 1.)

Item	Earthquake Criterion	Tornado Criterion	Sponsor[a]	Note

NOTES:

1. CAUTION, this table shall only be used for the classification of structures. Refer to the PAMS database for the classification of systems and components. A list of structures, systems, and components, like those in Table 15.2-1, was provided as part of the licensing application to permit a determination to be made as to the general suitability of the classification given and the design approach applied. Since the time of original plant licensing, an equipment classification listing (Q- List), was developed and subsequently replaced with a database (PAMS) to provide a more comprehensive and up-to-date list of individual components and their classifications than does this table, which only provides a general list of systems and components. According to the SPS current licensing basis, structures required to withstand the effects of a design basis tornado (Tornado Criterion "T") are also required to be designed to Seismic Category I requirements (Seismic Criterion "I"). Hence, all structures classified as "T" must also be classified as "I", but not necessarily vice versa. The Q-List and PAMS database only provide an input field for the more encompassing Seismic Category I classification for structures and do not provide a separate input field to identify those Seismic Criterion "I" structures that must also meet the Tornado Criterion "T" classification. Hence, SPS UFSAR, Table 15.2-1, was updated to be consistent with the SPS current licensing basis to reflect both the Seismic Criterion "I" and Tornado Criterion "T" classifications for structures at SPS in response to US NRC RIS 2015-06. For the classifications of systems and components at SPS, designed to be functional under Seismic Class I, Seismic Criterion "I", refer to the PAMS database.
2. The information in the sponsor column designates the division of responsibility between Westinghouse and Stone & Webster for the original design of listed structures, systems, and components. These designations are considered HISTORICAL and are not intended or expected to be updated for the life of the plant.
3. The extent of the "building collapse" in the Turbine Building, under a 250-mph maximum tornado wind speed, consists of the failure of the steel roof trusses. The overhead cranes and their supporting steel columns will remain in place, The operating deck and mezzanine decks will remain stable to provide tornado protection for safe shutdown and non-isolable water source components located below. Additionally, no damage will occur to any adjacent Criterion "T" structure or the protected components housed within (e.g., Service Building - Control House).

Table 15.2-2
DAMPING FACTORS FOR CLASS I STRUCTURES

Component	Percent of Critical Damping
1. Reactor vessel internals and control rod assembly drives	
a. Welded assemblies	1.0
b. Bolted assemblies	2.0
c. Control rod assembly drives	5.0[a]
2. Reinforced concrete reactor support structure, including the reactor vessel	5.0
3. Vital piping systems	
a. Carbon steel	0.5 OBE, 1.0 DBE[b]
b. Stainless steel	0.5 OBE, 1.0 DBE[b]
4. Containment structure and foundation	5.0
5. Steel framed structures, including supporting structures and foundations	
a. Bolted	2.5
b. Welded	1.0
6. Concrete structures aboveground	
a. Shear-wall type	5.0
b. Rigid-frame type	5.0
7. Mechanical equipment, including pumps, fans, and similar items	2.0

a. For Surry Unit 2 control rod assembly drives, the "Percent of Critical Damping" used is 5% as justified in Mitsubishi Heavy Industries Design Report, Reference 11.

b. In accordance with reference 4, the damping values of ASME Code Case N-411 (reference 5) have been approved for use at Surry as an alternate, for both the operating-basis earthquake and the design-basis earthquake.

The values specifically are: five percent below frequency of 10Hz; linear reduction from five percent to two percent between 10Hz and 20Hz and two percent above 20Hz. These damping values are used in the following situations and with the following additional considerations:

a. For seismic analyses in cases where new piping is added, existing systems are modified, existing systems are re-evaluated for support optimization.

b. For seismic analyses using response spectrum methods and not for seismic analyses using time-history analyses methods.

c. When these damping values are used, the ±15% peak broadening criteria of Regulatory Guide 1.122, *Development of Floor Design Response Spectra for Seismic Design of Floor Supported Equipment or Components*, will be used.

d. When these alternate damping values are used, they are used in a given analyses in their entirety.

Table 15.2-2 (CONTINUED)
DAMPING FACTORS FOR CLASS I STRUCTURES

Component	Percent of Critical Damping
e. When these damping values are used together with changes in the support arrangement that increases the flexibility of piping systems, the predicted maximum displacements are reviewed to ensure that such displacements do not cause adverse interaction with adjacent structures, components or equipments.	

15.3 MATERIAL

15.3.1 Concrete

See Section 15.5.2.4 for the description of the concrete used for the Reactor Pressure Vessel Head Replacement Project.

15.3.1.1 Cement

All cement used was an approved American brand conforming to the specification for Portland cement, ASTM Designation C150, Type II, low alkali. It is suitable for Class I structures because of its lower heat of hydration and improved resistance to sulphate attack. A low-content alkali was specified to minimize the possibility of reaction with aggregates. Certified copies of mill tests, showing that the cement meets or exceeds the ASTM requirements for Portland cement, were furnished by the manufacturer. An independent testing laboratory performed tests on the cement for compliance with the specifications.

15.3.1.2 Admixtures

An air-entraining agent was used in the concrete in an amount sufficient to entrain from 3 to 5% air by volume of the concrete. This agent conformed to the requirements of Standard Specification for Air-Entraining Admixtures for Concrete, ASTM C260, when tested in accordance with Standard Method of Testing Air-Entraining Admixtures for Concrete, ASTM C233.

The air-entraining agent was added separately to the batch in solution in a portion of the mixing water. The solution was batched by means of a mechanical dispenser capable of accurate measurement, and in a manner that ensured uniform distribution of the agent throughout the batch during the specified mixing period.

Water-reducing agents were used when their use was approved in writing. Water-reducing agents were Master Builders NB-100, type R or N, manufactured by Master Builders of Cleveland, Ohio. Type N is normal NB-100 and is used when a normal rate of hardening is required. Type R contains a retarder and is used in warm weather to reduce the rate of hardening and to avoid cold joints.

Calcium chloride was not used under any circumstances.

15.3.1.3 Water

Mixing water was obtained from a deep well and was kept clean and free from injurious amounts of oils, acids, alkalies, salts, organic materials, or other substances deleterious to concrete or steel. The quality of the water was the equivalent of that suitable for drinking. The water was continuously checked and tested for compliance with the above requirements by an independent testing laboratory.

15.3.1.4 **Aggregates**

Fine and coarse aggregates conformed to the requirements of the Standard Specifications for Concrete Aggregates ASTM C33. Aggregates were evaluated for potential chemical alkali reactivity. Aggregates were free from any materials that could have been deleteriously reactive in any amount sufficient to have caused excessive expansion of mortar or concrete. All aggregates were tested for compliance with the above requirements by an independent testing laboratory.

15.3.1.5 **Proportioning**

Proportioning of structural concrete conformed to ACI 301, Chapter 3. Working-stress-type concrete and ultimate-strength-type concrete conformed to the requirements of ACI 301, Paragraph 302. Ultimate-strength-type concrete was used in the construction of the foundation mat, exterior wall, and dome of the reactor containment. In general, working-stress-type concrete was used for other areas. Concrete mixes had a 28-day specified strength of 3000 psi, except as otherwise noted on the engineering drawings.

Proportions of ingredients were determined and tests conducted by an independent laboratory in accordance with the method detailed in ACI 301, Paragraph 308, for combinations of materials established by trial mixes.

The maximum slump of mass concrete, as defined in ACI 301, Chapter 14, in general did not exceed 3 inches. Slump of other concrete conformed to ACI 301, Paragraph 305. The samples for the slump tests were taken at the end of the last conveyor, chute, or pipeline before the concrete was placed in the forms.

The close and complex spacing of reinforcing steel in the heavily reinforced sections surrounding the equipment and personnel hatches results in the use of concrete with a maximum slump of 5 inches. The results of strength tests indicate that the 5-inch slump concrete will have a minimum compressive strength of approximately 4000 psi at 28 days. This is considerably higher than the nominal stipulated value of 3000 psi at 28 days used for design purposes, and demonstrates that the structural strength of the containment would not be jeopardized by the use of concrete with a slump of 5 inches.

15.3.2 Reinforcing Steel

Except for the No. 14 and No. 18 reinforcing bars for the foundation mat, exterior wall, and dome of the containment structure, all reinforcing conforms to Grade 40 (or higher strength steel) of the Standard Specification for Deformed Billet-Steel Bars for Concrete Reinforcement ASTM A615.

For No. 14 and No. 18 reinforcing bars and splices for the foundation mat, exterior wall, and dome of the containment structure, see Section 15.5.1.9. See Section 15.5.2.3 for the description of the reinforcing steel used for the Reactor Pressure Vessel Head Replacement Project.

Mill Test Reports showing chemical and physical properties were obtained and evaluated for each heat of steel used in making all reinforcing steel furnished.

15.4 CONSTRUCTION PROCEDURES AND PRACTICES

See Section 15.5.2 for the description of the restoration of the construction opening used for the Reactor Vessel Head Replacement Project.

15.4.1 Codes of Practice

Materials and workmanship conformed to the following codes and specifications:

ACI 301-66	*Structural Concrete for Buildings* and all specifications of the American Society for Testing and Materials referred to in Section 105 and declared to be a part of ACI 301-66 as is fully set forth therein.
ACI 304	Recommended Practice for Measuring, Mixing, and Placing Concrete.
ACI 305	Recommended Practice for Hot Weather Concreting.
ACI 306	Recommended Practice for Cold Weather Concreting.
ACI 318-63	Building Code Requirements for Reinforced Concrete.
ACI 347	Recommended Practice for Concrete Formwork.

See Section 15.5.2.1 for the description of the codes and specifications used for the restoration of the construction opening used for the Reactor Pressure Vessel Head Project.

Section III of the ASME Boiler and Pressure Vessel Code for Nuclear Vessels was used as a guide in the selection of materials, design stresses, and fabrication of the steel containment liner.

ACI 301-66, *Specifications for Structural Concrete for Buildings,* together with ACI 347-63, *Recommended Practice for Concrete Formwork*, and ACI 318-63, *Building Code Requirements for Reinforced Concrete*, formed the basis for the concrete specifications.

ACI 301-66 was supplemented as necessary with mandatory requirements relating to types and strengths of concrete, including minimum concrete densities, proportioning of ingredients, reinforcing steel requirements, joint treatments, and testing agency requirements.

Admixtures, types of cement, bonding of joints, embedded items, concrete curing, additional test specimens, additional testing services, cement and reinforcing steel mill test report requirements, and additional concrete test requirements were specified in detail.

Concrete protection for reinforcement, preparation, and cleaning of construction joints, concrete mixing, delivering, placing, and curing, with the following exceptions, equaled or exceeded the requirements of ACI 301:

Section 1404 (a) - Maximum slump was generally restricted to 3 inches to permit placing concrete in the heavily reinforced containment structures. The slump was increased to 5 inches in the areas of the containment wall adjacent to the equipment and personnel hatches where the large steel inserts and additional reinforcing steel required a more plastic mix for adequate concrete placement. All concrete mixes were designed and tested before use. All concrete mixes used in the work were fully documented.

Section 1404 (b) - Maximum placing temperature of the concrete when deposited conformed to the requirements of ACI 305-59, *Recommended Practice for Hot Weather Concreting*.

Section 1404 (c) - Minimum placing temperature of the concrete when deposited conformed to the requirements of ACI 306-66, *Recommended Practice for Cold Weather Concreting*.

15.4.2 Concrete

Concrete ingredients were batched in a batch plant and transferred to transit mix trucks for mixing, agitating, and delivering to the point of placement. Water was added to the mix with the other ingredients before the truck left the batch plant area. Batching and mixing otherwise conformed to ACI 301, Chapter 7.

Placing of concrete was by bottom-dump buckets, concrete pumps, or by conveyor belt. Bottom-dump buckets did not exceed 4 yd^3 in size. The discharge of concrete was controlled so that concrete could be effectively compacted around embedded items and near the forms.

For placing of concrete for the wall and dome of the containment structure, see Section 15.5.1.10. See Section 15.5.2.4 for the description of the concrete used for the Reactor Pressure Vessel Head Replacement Project.

Vertical drops greater than 6 feet for any concrete were not permitted, except where suitable equipment was provided to prevent segregation. All concrete placing equipment and methods were subjected to the approval of the structural engineer.

The surfaces of all construction joints were thoroughly treated to remove all laitance and to expose clean, sound aggregate. Surfaces of fresh concrete were roughened by cutting with an air-water jet after the initial concrete set had occurred, but before the concrete had reached its final set. After cutting, the surface was washed and rinsed. Where the use of an air-water jet was not advisable in any specific instance, then that surface was roughened by hacking with hand tools or other satisfactory means to produce the requisite clean surface.

Before placing subsequent concrete lifts, the surfaces of all construction joints were thoroughly cleaned and wetted, and all excess water that was not absorbed by the concrete was removed. Horizontal construction joints were then covered by a 0.50-inch-thick layer of sand/cement grout of the same sand/cement ratio as the concrete, and new concrete was then placed immediately against the fresh grout.

Curing and protection of freshly deposited concrete conformed to ACI 301, Chapter 12, using curing compounds conforming to ASTM C309.

For curing of the top surface of the containment foundation mat, see Section 15.5.1.10.

Concrete strength tests were performed in accordance with ACI 301, Chapter 16, Section 1602 (a), Paragraph 4, supplemented as follows.

No fewer than two sets of compression test specimens for each mix design of concrete placed were taken during the first two days of placing concrete, or at least one set of test specimens for each 250 yd^3 placed. Thereafter, one set of test specimens was taken for each 250 yd^3, or fraction thereof, for each mix design of concrete placed in any one day. In addition, one set of specimens was taken whenever, for any reason, the materials, methods of concreting, or proportioning were changed.

The test specimens for compressive strength were cylinders 6 inches in diameter and 12 inches long. Each set consisted of five specimens, at least one of which was tested at 7 days and three at 28 days age. The remaining cylinder was retained at the laboratory for further tests at 60 days age if the result of the previous tests made such a test desirable.

Concrete strength tests were evaluated by the engineers in accordance with ACI 214-65, *Recommended Practice for Evaluation of Compression Test Results of Field Concrete*, and ACI 301-66, Chapter 17.

Strengths of working-stress-type concrete were considered satisfactory if the average of any five consecutive strength tests of the laboratory-cured specimens at 28-days age was equal to or greater than the specified compressive strength, f'c, of the concrete.

Strengths of ultimate-strength-type concrete were considered satisfactory if the average of any three consecutive strength tests of the laboratory cured specimens at 28-days age was equal to or greater than the specified compressive strength, f'c, of the concrete.

If any tests for individual cylinders or group of cylinders failed to reach the specified compressive strength, f'c, of the concrete, the responsible engineers were immediately notified to determine if further action would be required.

The field tests for slump of Portland cement concrete were in accordance with ASTM C143. Any batch not meeting specified requirements was rejected.

Slump tests were made frequently during concrete placement and each time concrete test specimens were made.

Statistical quality control of the concrete was maintained by a computer program. This program analyzed compression test results reported by the testing laboratory in accordance with methods recommended by ACI 214, *Recommended Practice for Evaluation of Compression Test Results of Concrete*.

15.4.3 Reinforcing Steel

Placing of reinforcing steel conformed to the requirements of Chapter 5 of ACI 301, *Structural Concrete for Buildings*, and Chapter 8 of ACI 318, *Building Code Requirements for Reinforced Concrete*. See Section 15.5.2.3 for the description of the placement of the reinforcing steel used for the Reactor Pressure Vessel Head Replacement Project.

All Cadweld splices were made in accordance with the instructions issued by the manufacturer, Erico Products, Inc., Cleveland, Ohio.

In order to qualify operators for making Cadweld process joints, each operator was required to demonstrate to the Senior Quality Control Engineer his ability to make an acceptable fixed joint using the Cadweld process. Cadwelders were requalified after every 200 Cadwelds. Testing was by tensile testing a Cadweld made under simulated field conditions.

The ends of the reinforcing steel bars to be joined by the Cadweld process were square cut by the fabricator. Ends of the bars were then thoroughly cleaned of all rust, scale, grease, oil, water, or other foreign matter before the joints were made.

Welding was performed using the “Metallic Arc Welding Process” with coated electrodes, or the “Metallic Inert Gas Shielding Welding Process” (MIG) using bare wire. The filler metal for the Metallic Arc Welding Process conformed to ASTM A316, *Coated Arc Welding Electrodes*, Classification E-10016-D2 or E-10018-D2.

The filler metal for the MIG welding process was a spooled bare wire 0.30 inch or 0.35 inch in diameter, Linde or Arcos Type 515. The shielding gas used for the MIG welding process was Linde C-25, a mixture of 75% argon and 25% carbon dioxide.

The ends of the bars to be joined by butt welding were prepared by sawing or flame cutting, and dressing by grinding, where necessary, to form a single vee butt joint.

Mill test reports of the heats of steel used for making the rebars were obtained by the Senior Quality Control Engineer to confirm the grade of steel welded. Where preheating was required, temperatures were checked with Tempilstiks.

In order to qualify welders for work on the reinforcing steel bars, each welder made a reinforcing bar test weld in the horizontal fixed position, welding vertically up. Each test weld was sectioned through the center of the weld by power sawing and machining. The cross-sectioned surface was etched with a 10% solution of nitric acid and water. The etched surface was examined by the field welding supervisor, who determined the qualification of the welding operator.

Tack welding of rebar was not permitted.

Special criteria for placing reinforcement for the containment structure are provided in Section 15.5.1.6.

15.4.4 Construction Procedures

The portion of the site to be covered by structures was cleared, and general excavation performed to the underside of the foundations for the various buildings. In general, this excavation was from elevation +34 to +10, with some building foundations slightly higher or lower. The major Class I structures (except the Fuel Building and main steam valve enclosure structures) are supported on mat foundations; the Fuel Building and the main steam valve enclosure structures are supported on pile foundation. For additional construction procedures for other Class I structures, see Section 15.6.1.

15.4.5 Construction Practice

Vepco maintained quality control personnel on the site at all times to serve as qualified inspectors in all phases of work, so as to ensure and document that all construction operations met the rigid requirements of the specifications as outlined in the quality assurance report. The qualification of welding procedures and welders was performed in accordance with Part A of Section IX of the ASME Boiler and Pressure Vessel Code or, for structural steel, in accordance with American Welding Society requirements.

Concrete was sampled and tested during construction, in accordance with ACI 318, to ensure compliance with the specifications. A competent independent testing laboratory was retained to design the concrete mixes, take samples, perform all tests of aggregates and concrete cylinders, and report to Vepco for approval.

Special practices to be followed for the containment liner are contained in Section 15.5.1.8.

15.4.6 Quality Assurance Program (Construction Phase)

The descriptions of the quality assurance program during the construction phase have been deleted. These activities have been completed and the descriptions are no longer needed for the operational phase. The NRC-approved Operational Quality Assurance Program is described in Chapter 17.

Intentionally Blank

15.5 SPECIFIC CONTAINMENT STRUCTURAL DESIGNS

15.5.1 Containment Structure

15.5.1.1 General

For arrangement of the containment structure, see Reference Drawings 1 through 7.

Each of the reactor containment structures is similar in design and construction to that of the Connecticut Yankee Atomic Power Plant at Haddam, Connecticut. Each is a steel-lined, heavily reinforced concrete structure with vertical cylindrical wall and hemispherical dome supported on a flat base mat. Below grade, the containment structures are constructed inside a cofferdam of steel sheet piling. The structures are soil-supported. The base of the foundation mats is located approximately 66 feet below finished ground grade.

Each containment structure has an inside diameter of 126 ft. 0 in. The spring line of the dome is 122 ft. 1 in. above the top of the foundation mat. The inside radius of the dome is 63 ft. 0 in. The interior vertical height is 185 ft. 1 in., and the base mat is 10 ft. 0 in. thick. The steel liner for the wall is 3/8-inch thick, except over the base mat, where 0.25-inch and 0.75-inch plate is used. The steel liner for the dome is 0.50-inch thick. A waterproof membrane, as shown in Figure 15.5-1, is placed below the containment structural mat and carried up the containment wall to ground level. Attached to and entirely enveloping the part of the structure below grade, the membrane protects the structure from the effects of ground water and the steel liner from external hydrostatic pressure. Ground water immediately adjacent to the containment structure is kept below the top surface of the foundation mat by pumping as required.

Access to the containment structure is provided by a 7 ft. 0 in. i.d. personnel hatch penetration, and a 14 ft. 6 in. i.d. equipment hatch penetration. Other smaller containment structure penetrations include hot and cold pipes, main steam and feedwater pipes, fuel transfer tube, and electrical conductors.

The reinforced concrete structure has been designed to withstand all loadings and stresses anticipated during the operation and life of the unit. The steel lining is attached to and supported by the concrete. The liner functions primarily as a gastight membrane, and transmits incident loads to the concrete. The containment structure does not require the participation of the liner as a structural component. No credit has been taken for the presence of the steel liner in designing the containment structure to resist seismic force or other design loads.

The steel wall and dome liners are protected from potential interior missiles by interior concrete shield walls. CRDM missile protection is provided by a concrete shield on Unit 1 and a steel shield on Unit 2. The base mat liner is protected by a 1.50 to 2-foot thick concrete cover, except where a 0.75-inch-thick liner plate was used beneath the reactor vessel incore instrumentation, and at a drainage trench where floor grating provides additional protection.

As an added precaution against water seepage that might penetrate the waterproofing membrane in small quantities, pipe sumps are provided in each of the instrument observation pits located outside the cylindrical wall of the containment but within the waterproofing membrane. The sumps penetrate the base mat and terminate in the porous concrete immediately below the mat.

Pumps are provided to remove ground water outside the waterproofing membrane, as described in Section 15.5.1.3.

15.5.1.2 **Design Criteria**

The design of the containment structures is based on:

1. Biological shielding requirements.
2. The temperature and pressure generated by the design-basis accident (DBA), Section 14.5.2.
3. The operating and design-basis earthquakes discussed in Section 2.5
4. Severe weather phenomena.
5. The maximum calculated power level of 2597 MWt.

The design-basis accident was selected as the design basis for the containment structure because all other bases would result in lower temperatures and pressures. The containment structure is also designed for the normal subatmospheric operating conditions. Further, the containment structure is designated for a leakage rate not to exceed 0.1% of the contained volume per day at 45 psig.

The minimum operating pressure for the containment is 10.1 psia with about 1.0 psia additional partial water vapor pressure. The resulting total containment pressure is approximately 11.1 ± 0.5 psia. The temperature of the containment air fluctuates between a maximum temperature of 125°F and a minimum of 75°F during normal operation, and 60°F during shutdown, depending upon the ambient temperature of available service water. The normal operating pressure allows accessibility for inspection and minor maintenance during operation without requiring containment pressurization or the use of supplementary breathing equipment for personnel.

The containment structure is designed by ultimate strength methods conforming to ACI 318-63, Part IV-B. Design load criteria based on ACI requirements and others given below conform to current containment design.

The ultimate load capacity of the containment structure as modified by the safety provisions of ACI 318-63, Section 1504, is not less than that required to meet the containment structural loading criteria.

Loads imposed on the containment shell design include:

1. Dead load.
2. DBA pressure.
3. Temperature rise in liner associated with DBA.
4. Normal operating temperature gradients.
5. Earthquake.
6. Wind loads, including tornado winds.

Loads imposed on the containment mat design include:

1. Mat and interior structures during construction.
2. Dead load for complete structure and contents.
3. Dead load and DBA pressure and liner loading.
4. Dead load, DBA pressure, liner loading, and earthquake.
5. Dead load and earthquake.

The ultimate load capacity of the containment structure, as modified by the safety provisions of ACI 318-63, Section 1504, is not less than that required to satisfy the following structural loading criteria, tabulated in Table 15.5-1.

The seismic design coefficients and critical damping factors used in the design of the reactor containment structure are given in Section 15.5.1.4. The average acceleration spectra curves are included in Section 2.5. The earthquake loads include the horizontal or vertical acceleration, or a combination of both where the effects, as measured by the stresses resulting from the separate acceleration components, of horizontal and vertical ground accelerations are combined algebraically.

The load capacity of the tension members is based on the guaranteed minimum yield strength of the reinforcing steel. Load capacities of flexural and compression members are determined in accordance with the *Building Code Requirements for Reinforced Concrete,* ACI 318. The load capacity so determined is decreased by a reduction factor multiplier “ϕ”, to compensate for small adverse variations in material and workmanship. The reduction factors are listed in Table 15.5-2.

The load capacity reduction factor for stresses in concrete produced by tornado-carried missiles, in combination with other tornado-produced stresses as given in Loading Criteria 5, is 0.75.

The dominant design load is the 45-psig containment design pressure, which creates major tensile membrane stresses in the reinforcing steel, coincident with moments at the junction of the containment wall and mat.

The design tornado wind loading and pressure drop criteria are stated in Sections 2.2 and 15.2.3.

Since the DBA pressure load is greater than the negative pressure load of tornadoes, the containment structure is able to maintain its integrity and permit an orderly shutdown on the reactor unit should a tornado strike the structure.

15.5.1.3 **Buoyant Loads**

Yard elevation is at +26 ft. 6 in.; the base of the containment mat is at Elevation -39 ft. 7 in. Six seepage drains are provided to drain the area beneath the containment structure. Four drains extend down to Elevation -65 ft. 0 in., and two drains extend down to Elevation -105 ft. 0 in. These drains terminate in a 12-inch thick, crushed-rock layer placed immediately below the mat and through which water can travel to the edge of the cofferdam. Seepage from these drains, and other seepage into the cofferdam, collects inside the cofferdam around the base of the mat. Two pumps located in a cubicle adjacent to the instrument well remove all subsurface seepage water. To prevent loss of pumping capability, the system design permits access to critical areas, such as the interior drainage header, the pump cubicle, and backwash facilities. This will permit maintenance and continued operation of the drainage system, thereby preventing water levels from reaching the top of the containment base mat and exerting hydrostatic pressure on the top of the mat liner.

The pumps are controlled to maintain the water level in this space between a high of Elevation -32.75 ft. and a low of Elevation -33.4 ft., a range of 0.7 feet which is equivalent to a fluctuation in buoyant pressure under the structure of ± 22 lb/ft^2 from the mean value. A local high level indicator comes in if the water exceeds Elevation -32.6 ft. The dead load of the structure and its contents is 7200 lb/ft^2. This fluctuation in buoyant pressure amounts to 0.31% of the dead load weight.

In the unlikely event of multiple pump failure for a sufficient period of time for the ground water to rise to finished ground grade at Elevation +26 ft. 6 in. the buoyant pressure would increase to a maximum value of 4150 lb/ft^2, which amounts to less than 60% of the dead load structure. Therefore, flotation of the containment is not credible.

15.5.1.4 **Dynamic Analysis**

Analyses were conducted to determine response stresses in the containment structure due to the application of seismic loading. Earthquake ground motion values were applied simultaneously in the horizontal and vertical directions. Vertical ground motions were assigned a magnitude equal to two-thirds of the horizontal motions. The magnitudes of the operating-basis earthquake and the design-basis earthquake are derived and assigned as described in Section 2.5. Design loading conditions combined with seismic loading and allowable stress levels are stated in Section 15.5.1.2.

The earthquake loading was analyzed using a Stone & Webster program, *Container Vessel Seismic Analysis,* based upon the dynamic analysis of a containment structure by Messrs. Hansen, Holley, and Biggs of MIT.

The general analytical model of the containment structure responding to horizontal earthquake forces is a coupled two-mass system in which the wall and dome comprise one mass and the base slab and internals comprise the second mass. This model responds to three degrees of freedom: flexure in the wall and dome, translation, and rocking of the structure as a unit. The model includes the first three modes of vibration.

The stiffness of the wall and dome was obtained through formulas recommended by Professor R. V. Whitman of MIT, based on work by G. N. Bycroft.

The output of the computer program was spot-checked by manual analysis, which confirmed the program basis.

Another independent manual analysis that considered the internals as a third coupled mass resulted in loading values that were not greater than those obtained from the analysis of the two-mass system.

A preliminary analysis of response to vertical earthquake forces using a single-mass system showed that these forces are not controlling factors in the design.

When computing the response of the reinforced concrete containment structure to earthquake forces, the value of 5% of critical damping was used with the design earthquake acceleration of 0.07g. This is an overall value that includes the damping in both the reinforced concrete structure and the soil. The magnitudes of earthquake forces applied to the structure were obtained from the response spectrum for 0.07g at zero period and 5% critical damping at the calculated frequency of the structure, and then distributed over the structure in accordance with the relative motions of the structure as determined by dynamic analysis.

The force derived by use of this damping factor was used for the entire reinforced concrete containment. The value of 5% of critical damping, together with the damping factors for other systems, structures, and equipment, is listed in Table 15.2-2.

The value of 10% of critical damping was used with the design-basis earthquake of 0.15g on the basis of increased cracking in the concrete and increased movement in the concrete and soil.

To verify the damping used for design, an analysis of the soil structure interaction damping was made in accordance with the procedures suggested in *Analysis of Foundation Vibrations,* by

Robert V. Whitman, Proceedings of a Symposium organized by the British National Section of the International Association for Earthquake Emergency.

Damping factors for soil were calculated for the rigid body translation and rocking. Flexure damping was assessed as suggested by Newmark.

For each of the four modes of vibration, energy losses in structural flexure, sliding, and rocking were calculated and proportioned to determine the total system energy loss, thereby defining the damping to be used in spectrum response.

This analysis demonstrated that the damping factors used for design and the resulting seismic response characteristics are conservative.

Earthquake load criteria are included in the loading criteria described in Section 15.5.1.2. Operating and design-basis earthquake factors are each combined with other loads, including the design-basis accident pressure. Resulting shears are computed by the computer program.

Lateral earth pressure under seismic loadings on the containment mat was determined by computing the lateral resistance developed in the soil as the structure responds in flexure, translation, and rocking. In this analysis, the translational restraining force has two components, a shear across the base of the structure and lateral soil pressures on the side wall of the containment structure developed by its displacement relative to its static position.

The “spring constant,” that is, force per unit of lateral displacement by shear, for a circular rigid base on an elastic half space is given by Bycroft (Reference 1) as:

$$k_x = \frac{32\,(1-u)\,Gr_o}{7-8u}$$

where:

G = shear modulus

r_o = radius of base

u = Poisson’s Ratio

Note: Values in consistent units

For usual values of u this reduces approximately to:

$k_x = 5Gr_o$

The horizontal pressure on the side wall of the containment structure can be evaluated from the theories of horizontal subgrade reaction. From Terzaghi (Reference 2) the relation between horizontal deflection and pressure at any point is given by:

$$k_h = \frac{P}{y_h}$$

where:

P = horizontal pressure at soil structure interface

y = horizontal deflection of soil at interface

k_h = coefficient of horizontal subgrade reaction

further:

$$k_h = \frac{n_h z}{B}$$

where:

n_h = coefficient dependent upon physical properties of the soil

z = depth below free surface of soil

B = width of loaded area, which may be taken as diameter of containment structure

For purposes of this analysis, a value of n = 40 tons/ft^3 was selected from tables presented by Terzaghi. This value is appropriate to dense sand above the ground water table. It is a conservative value, since the higher the coefficient, the stiffer the soil, and the greater the loads imposed upon the side walls of the structure.

The rotational, translational, and flexural deflections of the structure were determined from response analysis and added so as to obtain maximum deflections. The lateral soil pressures on the side wall of the structure were then computed for these total deflections using the theory of horizontal subgrade reaction.

In determining these pressures, the side wall of the structure was assumed to be rigid radially, since radial deflection of the side wall would reduce relative soil-structure deflections, and thus the soil forces acting upon the structure.

The analysis was performed for both the operating-basis earthquake of 0.07g and the design-basis earthquake of 0.15g. The analysis for a 0.15-g earthquake indicates a lateral force of 300 lb/ft^2 at Elevation -8 ft. 6 in. which defines approximately the magnitude of this component.

It should be noted that these forces, if included in the seismic loadings on the structure, would reduce the base shear and vertical bending stresses in the shell. Accordingly, they are not included when computing such stresses in the shell and thereby contribute to the conservation of the design.

Rocking motion of the containment structure was considered in the determination of the natural frequency, the distribution of inertia forces, and in the amplitudes of motions.

The containment wales supporting the cofferdam structure do not affect consideration of horizontal pressure under seismic loading on the containment wall.

Four circular concrete wales originally supported the sheet steel cofferdam in which the containment structure is founded. The top wale, Wale A, has been partially removed at several points to permit completion of adjacent structures; in this condition it does not impose any restraint on the containment structure. The bottom wale, Wale D, is in the lower plane of the containment mat and below the plane of the wall, and offers no restraint. Wale C extends from a height of 4 ft. to 8 ft. above the base of the wall. Wale B extends from a height of 17 ft. 6 in. to 21 ft. 6 in. above the base of the wall. These two wales are approximately 3 ft. 9 in. from the containment wall, and the space between the wales and wall is backfilled with pervious fill. Under seismic loading, the distribution of the lateral earth pressure through the cofferdam wales would not have any different effect than if these pressures were applied directly to the structure.

15.5.1.5 **Static Analysis**

The containment structure was analyzed and designed for all loading conditions combined with load factors as outlined in Section 15.5.1.2. The forces, shears, and moments in the structural shell were obtained from a computer program based on *Numerical Analysis of Unsymmetrical Bending of Shells of Revolution*, by B. Budiansky and P. P. Radkowski, published in the American Institute of Aeronautics and Astronautics Journal, dated August 1963.

Forces, moments, and shears in the base slab were obtained from a Stone & Webster computer program, *Flat Circular Mat Foundations for Nuclear Secondary Containment Structures*. The program analyzes a flat circular plate supported on an elastic foundation and computes the discontinuity stresses at the junction of the mat and cylinder, and the soil bearings pressure.

Discontinuity stresses, shears, and moments at the junction of the cylinder and mat were determined using an analogy to the Hardy Cross method for distributing fixed-end moments in continuous frames. The theoretical fixed-end moments obtained from the shell and mat computer analysis were balanced in proportion to the relative stiffness of the mat and cylinder.

An independent, manual computation, based on *Theory of Plates and Shells*, by S. Timoshenko, at a few selected points produces forces, shears, and moments substantially the same as those produced by the computer programs for the shell and the mat.

The containment shell program used to derive stresses in the shell assumes an isotropic material. The program does not include considerations of temperature gradients due to the thermal loadings across the containment wall.

To compute maximum stresses due to the thermal load, six general strain equations were derived, one equation for each of the four principal areas of reinforcing steel and one for each major axis of the steel liner. These equations relate strain to position, temperature, and incident stress for each item considered. To solve these general strain equations, six additional equations were used: four equations for strain compatibility, which equate radial and longitudinal strains, and two equations for load equilibrium. The solution of these equations for incident conditions gives the stress in each of the principal areas of reinforcing steel and the stress on the steel liner.

These equations permit the thermal stresses to be considered separately without modification of the major shell program.

The thermal operating load in the containment concrete wall, combined with incident condition loadings, produces a stress difference of approximately 6000 psi between the reinforcing steel adjacent to the inside face of the wall and the reinforcing steel adjacent to the outside face of the wall. This difference exists in both the longitudinal steel and the hoop reinforcing steel.

To permit the addition of these stresses to those obtained from the containment shell program, without exceeding the maximum, the containment shell program stresses are limited to 3000 psi below the maximum allowable design stress. This approach is considered extremely conservative since it limits the design stress in the interior layers of reinforcing steel to approximately 6000 psi, less than the maximum allowable design stress permitted on the exterior layers of reinforcing steel.

Structural failure cannot occur, however, until the interior reinforcing steel exceeds yield. Up to that point plastic yielding of the outside reinforcing would be controlled by the elastic behavior of the interior steel.

In the solution of the general strain equations, the effect of the concrete has been ignored, since it is assumed to be cracked and incapable of carrying any of the tensile loads considered. The dead load of the concrete is also ignored, as this was found to have little effect on the hoop stresses. This assumption also provides a more conservative result.

The loads exerted on the concrete shell by the thermal effects of the exposed steel liner were obtained from the calculations discussed above. The equivalent pressure, p, equals the hoop stress, f, in the steel liner multiplied by the liner thickness, t, and divided by the radius of the liner, r. The computed equivalent pressure associated with 1.5 times incident pressure equals 5.45 psi.

Stiffness factors were used to distribute computed fixed-end moments derived from an analysis of the containment cylindrical wall, considered as a shell with a fixed-end moment, and from an analysis of the containment mat, considered as a flat circular plate with uniform fixed-edge moment.

Stiffness factors for the cylinders were computed from formulas given in Raymond J. Roark's book, *Formulas for Stress and Strain*, for long, thin-walled cylinders. Stiffener factors for the mat were computed from formulas for circular flat plates with uniform edge moment, from the same source.

Variation of the modulus of elasticity of the concrete to differentiate between uncracked and cracked concrete was not considered in determining the stiffness factors chosen.

Use of such a variable would modify the distribution of the moments and shear forces to some degree, but it is not believed that this would significantly affect the accuracy of the results. The safety factor inherent in the present design would accommodate such small variations.

The actual distribution of the moments and forces at the junction of the wall and mat are a function of the relative stiffness of each member. This is determined by the design approach used. Provided the total forces are distributed between the two areas under consideration, differences of distribution due to theoretical variations of the theoretical value of Young's Modulus for concrete are not considered likely to improve the results beyond the accuracy obtained with the assumptions already used.

The methods for computing soil pressures under the mat were based upon an analogy to E. P. Popov's *Method of Successive Approximations for Beams on an Elastic Foundation,* published in the Proceedings of the ASCE, Separate No. 18, dated May 1950. The program computes the deflection at the center of the mat relative to a point on the mat at the intersection of the center line of the containment shell walls. The elastic curve of the mat deflection is assumed to be parabolic between these two points. Multiplying the deflection by the subgrade spring constant, the program then provides a parabolic soil pressure curve, which is combined with the rectangular soil pressure curves to provide final soil pressures under the mat. The subgrade spring constant is derived from Professor R. V. Whitman's formula:

$$k = \frac{4G}{\pi(1 - U)R}$$

where:

k = Spring constant

G = Shear modulus of subgrade material

R = Radius of mat

U = Poisson's ratio of subgrade material

While the subgrade reaction varies with depth, a single typical value for the reaction was used which is representative of the zone at the level being considered. The shear modulus was computed using a formula developed by Hardin and Black (Reference 3) from observed soil samples, and substantiated by dynamic triaxial tests of the soil. The stiffness of the soil was also based on work by G. N. Bycroft which is referred to in the Section 15.5.1.4.

A variable soil pressure conforming to the deformation of the mat was used in determining the stresses in the structure.

Maximum wind velocity associated with a tornado is given as 360 mph. This velocity was converted to an equivalent pressure using the formula $P = .00256V^2$, where P = equivalent pressure, lb/ft^2 and V = wind velocity, mph. Wind pressure was distributed over the containment dome in accordance with the methods given in *Wind Stresses in Domes,* by P. Gondikas and M. G. Salvadori, published in ASCE proceedings No. 2616, dated October 1960.

Wind pressure was distributed over the containment cylindrical shell in accordance with the methods given in *Wind Forces on Structures*, by T. W. Singell, published in ASCE proceedings No. 1710, dated July 1958.

Tornado wind loads were combined with other loads as described in Section 15.5.1.2.

An analysis of the containment structure indicated that resulting membrane stresses due to tornado wind loading in the dome reinforcing are less than 5000 psi, and that discontinuity stresses at the junction of the dome and cylinder are somewhat less.

The wind loading on the cylindrical shell creates bending, direct and shear stresses. The bending and direct stresses in the horizontal reinforcing equal 16,000 psi.

An investigation of overturning due to wind shows that the resultant (DL + wind) falls within the Kern point radius of the cylinder, indicating that the vertical reinforcing will not be subject to tensile forces from this load.

Containment torsional loadings from wind were considered negligible, in view of the ideal shape of the containment when considered as a torsion resistant shell supplemented by the diagonal reinforcing throughout the walls provided to resist earthquake loads.

The Stone & Webster computer programs for the reactor containment base slab, cylindrical wall, and dome use a constant Young's Modulus of Elasticity and Poisson's Ratio. No attempt was made to assign varying numerical values to these factors to differentiate between the relative amount of cracking in different parts of the structure.

The output of the mat program furnishes the following information:

1. Radial and tangential bending moments and vertical shear at five-foot intervals along horizontal radii from the center of the mat, spaced at 30-degree intervals.

2. Discontinuity stresses at the junction of the mat and cylinder.
3. Soil pressure.

The output of the shell program furnished forces, shears, and moments at 1-foot intervals in the height of the cylindrical wall, and at one-degree intervals in the height of the dome. Similar information is furnished at each of 16 equidistant points on the circumference of the vessel at each level considered.

Scaled load plots obtained from the computer programs for moment, shear, deflection, longitudinal force, and hoop tension are shown in Figure 15.5-2 for each of three design load conditions. The fourth design load condition did not govern design and is not represented.

The following assumptions were made:

a. The dead and live structural loads are included in all three of the design load cases.
b. Pressure load, factored and unfactored, is the dominant load condition.
c. Wind loading replaces earthquake loads where wind loads exceed earthquake loads.
d. Tornado loads are included under the general category of wind loads discussed above.
e. Buoyant water loads as discussed in Section 15.5.1.3 are substantially less than dead loads.
f. Earthquake loads, both for the operating-basis earthquake and the design-basis earthquake, are included in the analysis.
g. Thermal load from the liner is converted into an equivalent pressure and added to the incident pressure load when computing moments, shear, and tension associated with the design-basis accident.
h. Thermal load from the concrete is discussed in Section 15.5.1.5. Stresses resulting from this load are combined with incident pressure load stresses.

15.5.1.6 Reinforcing Steel Arrangement

The foundation mat of the containment structure is reinforced with both top and bottom layers of reinforcing. Bottom mat reinforcing is placed in a rectangular grid pattern with layers at 90 degrees to each other. Reinforcing for the top of the mat consists of concentric circular bars combined with radial bars. The reinforcement pattern for the top of the mat is arranged to permit maintaining a uniform spacing of the vertical wall rebars that extend into the mat. Splices in adjacent parallel rebar in the mat are in general not less than 4 feet apart.

Hoop tension in the cylinder wall is resisted by horizontal bars located near both the outer and inner surfaces of the wall. All horizontal circumferential bars, including those in the dome, have their joints staggered at a minimum of 3 feet apart.

Longitudinal tension in the cylinder wall is resisted by two rows of vertical bars, one near the interior face and the other near the exterior face of the wall. Vertical bars are placed in groups of 20 bars of equal length. These are arranged so that no adjacent group in the same or opposite face of the wall has splices closer than 6 feet vertically.

See Section 15.5.2.3 for the description of the splicing scheme used for the Reactor Pressure Vessel Head Replacement Project.

The dome reinforcing consists of layers of rebar placed radially extending from the vertical reinforcing of the cylindrical wall and horizontal layers of circumferential hoop bars. Layers are located near both the inner and outer faces of the concrete. The radial pattern of the reinforcing steel terminating in the containment dome results in a high degree of redundancy of reinforcing steel in the dome. Bars are terminated beyond a point where there is more than twice the amount of steel required for design purposes. The rate of convergence of these bars, and low-stress requirements dictated by the arrangement, produces a low bond stress. In a limited number of cases where bars are terminated close to the center of the dome, anchorage stresses are more critical, and bars are hooked to provide the required anchorage. Near the crown, the rebars are welded to a concentric ring cast in the concrete.

Radial shear loads generated by internal pressure resulting from the design-basis accident are resisted by rebars inclined at 45 degrees with the horizontal and extending between the surfaces of both the vertical reinforcing closest to the interior and exterior faces of cylinder wall. This radial shear will vary from a maximum at the base of the wall where the foundation mat restrains the independent movement of the wall to zero at some level above the mat. Anchorage bond stresses in these shear bars is kept below allowable stress levels to minimize potential cracking of the concrete. In addition, sufficient longitudinal and circumferential reinforcing is carried to the base of the wall to carry all potential loads without assistance from the radial shear reinforcing.

The tangential shears resulting from the earthquake loading are resisted by rebars inclined at approximately 45 degrees in each direction, in the plane of the wall parallel to the main reinforcing steel.

Minimum concrete cover for all principal reinforcing steel of the containment structure exceeds the requirements of ACI 318, Paragraph 808(d), which states, “Concrete protection for reinforcement shall in all cases be at least equal to the diameter of the bars.” The largest and principal reinforcing bar is No. 18, which requires a minimum cover of only 2-3/8 inches by the code.

15.5.1.7 **Penetration Design**

Penetration through the containment structure is divided into one of the following three categories:

1. Pipe penetrations nine inches in diameter or less.

   No special structural reinforcing is provided for penetrations nine inches in diameter or less. Penetrations in this category are located to avoid interference with the reinforcing steel.

2. Pipe penetrations greater than nine inches and up to 3 ft. 6 in. in diameter.

   For penetrations greater than nine inches, and up to and including 3 ft. 6 in. diameter, supplementary reinforcement is provided in amount and distribution such that area requirements for reinforcement are adequately satisfied.

   At all these size penetrations, reinforcing steel interrupted by the openings is terminated at each side of the opening. Supplementary reinforcing was placed parallel to the interrupted bars to provide bar continuity. Horizontal, diagonal, and vertical bars were used to effectively frame the opening. The total area of reinforcement provided in any plane is not less than twice the area of steel interrupted or cut by the opening, with half of this placed on each side of the opening.

   Additional reinforcing around these openings is not less than 20 feet in length, and of sufficient length to develop the full ultimate strength of the bar in ultimate bond stress to conform to the requirements of ACI 318, Section 1801(C 2). Horizontal bars are considered as top bars for this purpose.

3. Openings larger than 3 ft. 6 in. in diameter.

   The two openings in this category are the 7 ft. 0 in.-diameter personnel access hatch and the 14 ft. 6 in.-diameter equipment access hatch. Details of the additional reinforcement provided around the equipment access hatch and personnel access hatch are shown in Figures 15.5-3 through 15.5-6, inclusive.

These penetrations are analyzed by means of a computer program (Reference 4). This program analyzes a ring beam based on the method of virtual work. The program assumes the ring beam to be isolated from the containment shell and loaded in two planes. The analysis includes the effect of the stiffened ring and the moments introduced by transferring external loads from the shell at the perimeter of the ring to the center line of the beam.

The ring beams are designed to resist biaxial bending moments, axial tension, torsion, and biaxial shear resulting from loading criteria listed in Section 15.5.1.2. The biaxial bending moments and axial tension are assumed to be resisted by the reinforcing bars only, the concrete being neglected. The torsional and biaxial shear stresses are assumed to be resisted entirely by binders placed radially around the penetrations. Torsion is computed by the formulas for torsion in a rectangular beam. The principal circumferential and meridional reinforcing is extended to the inner face of the ring beam and bent at right angles, hereby providing additional shear resistance, the availability of which is considered in the design.

The normal pattern of membrane stress in the cylinder wall is interrupted in the area adjacent to the stiffened openings. This redistribution of stress was investigated by means of a computer program, based upon a paper by B. Budiansky and P. Radkowski (Reference 5). For this investigation, a flat circular plate with a radius equal to three times the distance from the center of the opening to the outside face of the stiffening ring beam was used to establish the stress pattern. The movement of both the stiffened ring and the adjacent shell was compared to determine if significant discontinuity stresses were present. Extra reinforcement was added to regions of marked deviation from the normal pattern to keep the discontinuity effects to the level at which they can be considered negligible. The gross concrete area of the ring section was used to determine the section stiffness and rigidity.

15.5.1.8 **Steel Liner and Penetrations**

The containment structure has an inside diameter of 126 ft. 0 in., and an interior vertical height of 185 ft. 1 in., measured from the top of the foundation mat to the center of the dome. The cylindrical steel wall liner is 3/8 inch thick, the hemispherical dome liner plate is 0.50 inch thick, and the flat base liner is 0.25 inch and 0.75 inch thick.

See Section 15.5.2.2 for the description of the restoration of the steel liner for the Reactor Pressure Vessel Head Replacement Project.

The top of the containment dome at Surry has a 39-inch penetration that was used during construction. This penetration is sealed by a welded plug on the liner side and a bolted plate on the outer end, and is filled with sandbags.

The steel lining is attached to and supported by the concrete; the liner functions primarily as a gastight membrane. The steel wall and dome liner are protected from potential interior missiles by interior concrete shield walls. CRDM missile protection is provided by a concrete shield on Unit 1 and a steel shield on Unit 2. The base liner is protected by a 1.50- to 2-foot-thick concrete mat, except in two areas where 0.75-inch-thick liner plate is used beneath the reactor vessel incore instrumentation, and at a drainage trench where floor grating provides additional protection.

The steel liner is designed to withstand the effects of all temperature, earthquake, and pressure loads, including the effect of the subatmospheric operating pressure.

The liner stress limits and their associated strains are limited to the stress criteria given in Paragraph N-1314 of Section III of the ASME Boiler and Pressure Vessel Code for nuclear vessels, and to basic primary stress levels taken from Table N-421 of that Code. The liner material SA-442-GR60 has a specified NDT that is at least 80°F below the minimum liner operating temperature, and considerably more than 120°F below the design-basis accident temperature. Under either of these conditions, the liner material is able to accommodate at least 60% plastic strain without cracking. A strain of this magnitude is at least 80 times greater than the maximum strain that will be imposed on the liner.

Reference to a generalized fracture analysis diagram shows that the "Crack Arrest Temperature" (CAT) curve crosses the NDT +80°F line at approximately 60% of the span between the "Fracture Temperature Elastic" (FTE) and the "Fracture Temperature Plastic" (FTP) ordinates, indicating that the steel can be strained to 60% of the required strain to fracture without cracking, even in the presence of large flaws.

To demonstrate that this plate material can accommodate plastic strains of this magnitude when biaxially stressed, tests were conducted on samples of 3/8-inch-thick plate of identical specification to the steel to be used in this containment liner, at a temperature of 90°F above the NDT of the steel. In these tests, the plate samples were each laid across a 23-inch-diameter ring, and a 3-5/8-inch-diameter mandrel was forced into the plate at the center line of the ring. In all cases, the mandrel deformed the plate by an amount in excess of 4 inches before shearing through.

The design-basis earthquake can be expected to produce tremors to the extent of not more than 8 to 10 cycles, and the operating-basis earthquake not more than 4 to 5 cycles.

Operating pressure variations from 9.5 psia to 14.7 psia can be expected to occur not more than 200 times during the lifetime of the unit, since personnel access is permitted under subatmospheric conditions. Temperature variations from 70°F to 105°F resulting from seasonal swings and shutdowns of the unit can be expected to occur not more than 800 times during the lifetime of the unit.

The containment liner is designed for 2000 cycles of operating pressure variations, 8000 cycles of temperature variation, and 20 cycles of design-basis earthquake, all simultaneously applied.

The containment liner is also designed for one cycle of design-basis accident pressure, one cycle of design-basis accident temperature, and ten cycles of design-basis earthquake, all considered simultaneously applied.

The containment liner is designed, within allowable working stresses, to withstand a vacuum increase of not less than 1.5 psi. The shell and dome plate liner is capable of withstanding an internal pressure of 3 psia, and the bottom mat liner is capable of withstanding an internal pressure of 8 psia, with reference to standard atmospheric conditions outside the containment.

The change in barometric pressure due to tornadoes is not expected to exceed 3 psig, and the change due to maximum hurricane will be approximately 1.1 psig. These pressure changes will result in a decrease in the atmospheric pressure, which will decrease the differential between atmospheric pressure and the containment structure ambient pressure, thereby decreasing the potential for stresses in the containment.

The accumulated effects of the above are evaluated in accordance with Paragraph N-415.1 of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

The steel containment liner is securely anchored to the concrete wall and dome with Nelson stud-type concrete anchors. Failure could occur by stud failure in shear or tension, by studs pulling out from the concrete, or by studs tearing off from the liner plate. Tests conducted by Northeastern University, Boston, Massachusetts, using 1/2-inch-diameter studs and 3/8-inch-thick plate, show that shear failure occurs in the stud adjacent to the weld connecting the stud to the plate; in no instance was the plate damaged. Tests conducted for the stud manufacturer under the direction of Dr. I. M. Viest indicate that, with the manufacturer's recommended depth of embedment of the stud in concrete, the ultimate strength of the stud material can be developed in direct tension.

The principal design load imposed on the studs is due to the subatmospheric pressure operating condition, with the anchor lattice spacing based on considerations of plate buckling. A safety factor greater than 10 is provided against stud failure in tension.

Shear due to design-basis accident conditions and earthquake will result in stresses less than the allowable working stresses.

In addition to the concrete stud anchors, the wall and base mat sections are anchored and joined at the intersection of the vertical wall and the base mat with a continuous steel skirt embedded and anchored in the concrete.

All anchors are designed so that failure occurs in the anchor, thereby assuring that the leaktightness of the containment liner will be maintained during and after anchor failure.

Probable mode of failure will be one of random stud failure due to poor workmanship during stud attachment. This type of failure will result in separation of the stud from the liner without impairment of the liner ductility or integrity.

Loss of random anchor points will not trigger a chain reaction, since the design load on each stud is low compared with the stud load capability. Design spacing of these studs is such that a group of at least 10 adjacent studs would have to fail to cause a liner plate to reach its yield stress under design operating conditions. Even with this unlikely condition, the loads on the studs adjacent to this area would remain within their safe load capability.

As shown in Figure 15.5-7, the liner was welded to a skirt ring which in turn is embedded and anchored into the concrete mat. The skirt-to-liner juncture and the skirt-to-mat anchorage were proportioned to develop the full strength of the liner. Under DBA conditions, the liner at the base juncture will be under a state of biaxial compressive strain, due primarily to thermal effects.

All thermally hot pipes penetrating the reinforced concrete containment wall pass through individual sleeves that are approximately 1 foot in diameter larger than the pipe, and project inward a distance of approximately 2 feet from the liner. A typical application is shown in

Figure 15.5-10. The pipe is welded to a thick cap that is an integral part of the end of the penetration sleeve.

Each penetration sleeve with a thermally hot pipe penetration is equipped with two water-cooled heat exchangers to limit the temperature of the liner and the concrete in contact with the sleeve. One heat exchanger is located inside the sleeve encompassing its length (inner unit); the other is located outside the penetration sleeve in proximity to the liner. Either of the heat exchangers will provide adequate cooling for the penetration if the other is out of service. The associated component cooling water system has two independent lines. One line circulates water through the outer unit; the other circulates water through the inner unit. The inner unit limits the radial heat flow resulting from convection and thermal radiation from the thermally hot pipe penetration, to keep the temperature of the concrete in contact with the sleeve within allowable limits. In addition, the inner unit controls the longitudinal heat flow resulting from conduction from the same heat source, thus limiting the temperature of the liner and temperature gradient along the sleeve to keep the resulting thermal stresses in the liner and sleeve within the limits set forth in Section III of the ASME Pressure Vessel Code. The outer unit also limits the longitudinal heat flow, providing independent thermal protection of the penetration sleeve and liner.

The circumferential groove in the attachment plate, between the sleeve and penetration with its outside threaded connection, serves as a test chamber for the testing of the welds joining the attachment plate and penetration.

All penetrations are anchored in the reinforced concrete containment wall. The anchor strength is equal to the full yield strength of the pipe with regard to torsion, bending, and shear, and to the maximum possible pipe jet reaction. All stresses induced in the liner by these combinations of loadings are only those reflected by the resulting distortions in the reinforced concrete containment wall, and are minor in intensity. So, loads will not be imposed on the liner, thereby preserving its integrity.

All highly stressed insert plates at penetrations and equipment supports that are welded into the liner to transfer loads into the concrete have been ultrasonically tested to check for possible laminations. Tests were conducted on all plates where analysis showed a higher than average stress field, although all such plates are stressed well below the allowable limits for the materials. These tests show that no faults exist in the insert plates.

The pipes anchored to the containment penetrations between containment isolation valves constitute an extension of the containment, and are designed in accordance with the *USA Standard Code for Pressure Piping - Power Piping,* USAS B31.1.0-1967, with respect to materials and allowable stress. Analyses of stresses due to thermal expansion and shock loadings from earthquake, pipe jet reaction, and other causes were made using established digital computer calculation techniques.

In order to determine the loading combinations that act on a penetration, the pipe line passing through the penetration sleeve was assumed to have failed transversely at several locations along its run. The location at which the reaction of the ensuing jet of fluid flowing from the broken end first causes the pipe to completely yield, in either bending or torsion, was taken as the design case from which all resultant combinations of penetration loading were determined for that particular pipe line. The maximum stress allowed on any individual element of the penetration is 90% of the minimum yield point.

The intent of this criterion is to keep the material assembly components within the elastic range of the material. Under operating conditions of pressure, temperature, and external loads, the stresses in the assembly will be within the limits established in Section III of the ASME Pressure Vessel Code.

As a part of the issues identified in NRC GL 96-06, isolated containment penetration piping with confined fluid was reviewed for susceptibility to thermal over-pressurization following a DBA. The linear elastic analysis criteria stipulated in the 1989 version of the ASME Boiler and Pressure Vessel Code Section III, Appendix F was used for structural integrity evaluation. The internal pressure in piping penetrations during a design basis accident (LOCA or MSLB) was calculated by taking into account the difference in the expansion of the fluid and the pipe, the temperature increase immediately following the DBA and credit for a limited amount of circumferential strain in the pipe. The analysis established that thermally induced over-pressurization of isolated water-filled piping sections in the containment boundary could not jeopardize the ability of the accident mitigating systems to perform their safety functions and could not lead to a breach of containment integrity (Reference 10).

All liner seams were strength-welded. Small steel channels welded continuously along the edges of their flanges to the liner plate cover the plate weld seams, in a manner similar to those installed at the Connecticut Yankee Station. These channels are zoned into test areas by dams welded to the ends of the sections of the channels. Fittings are provided in the channels for periodic testing of the weld seams for leaktightness under pressure. Typical liner details are shown in Figure 15.5-12. Testing of the liner is described in Section 5.5.

To transfer the stress adequately around penetration openings, or to transfer the pipeyield load adequately to the concrete within the limits of this material, whichever is larger, the liner is reinforced in accordance with the rules set forth in the ASME Boiler and Pressure Vessel Code, 1968, Section III, Nuclear Vessels.

All major equipment and pipe loads are carried on the interior concrete structure or by the neutron shield tank. A 1.50- to 2-foot-thick concrete slab placed over the bottom mat steel liner provides anchorage and support for other equipment located in the base of the containment structure. The neutron shield tank skirt is attached to the containment mat by 1.50-inch-diameter anchor bolts. The skirt support was welded to the liner, and the entire weld, including the anchor bolts, covered by test channels. The internal concrete structure is attached to the containment mat by lengths of 3-inch by 6-inch steel bars which, placed horizontally, intersect the steel plate liner as shown in Figure 15.5-8. The main vertical reinforcing steel bars were welded to the top and bottom faces of these bars, thus providing bar continuity without creating multiple penetrations through the liner.

The 1.50-foot-thick concrete slab is anchored through the steel liner plate in a similar manner using 7-inch by 0.50-inch bars, as shown in Figure 15.5-8. These bars, termed bridging bars, form an integral part of the steel liner, and conform to the material and workmanship specifications of the steel liner. All welded joints are covered by test channels and tested as all other liner plate joints.

Access to the containment structure is provided by a 7 ft. 0 in. i.d. personnel hatch and a 14 ft. 6 in. i.d. equipment hatch. Other smaller containment structure penetrations include hot and cold pipes, main steam and feedwater pipes, fuel transfer tube, and electrical conductors.

Electrical conductors penetrating the containment structure range in size from No. 16 AWG thermocouple leads to 1-inch-diameter solid copper rods for 4160V power circuits. Each penetration group passes through 8-inch-diameter steel sleeves. The sleeves were welded into the containment liner with a test channel around the weld for periodic leak testing, as shown in Figure 15.5-9 (Amphenol electrical penetration depicted).

The basic Amphenol electrical penetration consists of an eight-inch steel tube with bolted-on flanges, through which pass the sealed conductors. The hermetically sealed connectors, as shown in Figure 15.5-9, were bench-tested for leaktightness.

Each flange is held tightly in place with eight bolts that draw the flange against a high temperature sealing ring and a backing plate welded to the sleeve. Each flange is tapped for leak testing. A make-up method is used to determine the penetration leakage by applying a test pressure equal to greater than containment design pressure (45 psig) between the o-ring seals. An electrical connector may be replaced, if necessary, without welding or cutting the containment liner or sleeve.

The design and qualifications of the Amphenol electrical mating connectors are based upon the requirements of military specification number MIL-C-5015. Connector design is such that silastic components are provided in the connector to feed through the interface. This type of interface has been proven adequate to meet the environmental requirements of MIL-C-5015. Additional capability to withstand elevated temperatures is provided in the material used for the sealing members.

The original tests conducted at the Amphenol’s shop consisted of the following:

> Connectors installed in the flanges normally operate at ambient conditions of 105°F and 9.75 psia, and were tested for leak rate and tagged for integrity before shipment to the job. A test facility was set up by the manufacturer suitable for 50 psig, with provisions for thermocycling from 32° to 300°F. A thermocycle run of at least three cycles was made on one of each type flange. A time interval of 30 minutes was

> allowed between the thermocycles. The leak rate test after thermocycling was made at 50 psig and 300°F. Each completed flange had a leak rate of less than 1×10^{-6} cc/sec per assembled flange. All flanges were leak tested at 50 psig and 300°F. Helium gas was used in the test facility.

For the Amphenol triaxial cable penetrations a more detailed procedure for the thermocycle test was followed in shop test:

> The type sample consisted of a containment side flange disk with hermetic assemblies welded in place. A thermocouple was installed to monitor disk temperature. The disk was stabilized at 32°F and then placed in an oven heated previously to 280°F. On entrance of the disk, the oven temperature was reduced, straight line, to 150°F over a 60-minute period. The disk was removed and cooled to 100°F, while the oven was reheated to 280°F. The disk was then returned to the oven and the oven temperature reduced to 150°F as before. The highest metal temperature reached during this cycle was recorded and a 50-psig helium leak test was conducted at this metal temperature for all discs of this type.

Each Amphenol penetration assembly, without external cable mating connectors, was tested in the factory to demonstrate insulation resistance of at least 1000 megohms at 1000V dc. In addition, each penetration has passed an overpotential test. After initial installation, each penetration with external cables connected was tested at 1000V dc for 5 minutes.

Containment electrical penetrations now in use at the Surry Power Station were manufactured by either Amphenol Space and Missile Systems, Conax Corporation, or Westinghouse Electric Corporation. Nitrogen pressure is not required for penetration functional capability; however, each penetration is capable of being pressurized with nitrogen for leak detection purposes. RTV-8112, THIOKOL, or POLYSYLFONE are used to provide a tight seal around conductors.

Amphenol penetration electrical connectors were tested by D. G. O'Brien, Inc. in 1972. The purpose of this test was to demonstrate operability during simulated LOCA conditions. The connectors passed the test with no less than 34 megohms internal resistance while retaining complete electrical continuity. The test had no observable physical effect on the connector assembly or cable. No connectors are associated with the CONAX or Westinghouse type penetrations; however, both manufacturer's have provided data regarding the performance of the materials used in their penetrations. This information includes thermal performance, radiation resistance, and chemical resistance tests. All data indicate excellent performance characteristics for a LOCA environment.

All containment structure piping penetrations consist of a basic containment insert, plus additional items, as required for the individual services. Two basic types of penetrations are used for piping systems:

1. Unsleeved - These penetrations consist of piping installed through the containment wall without a sleeve around the outside of the piping. Unsleeved penetrations are used for cold piping systems (temperature of the fluid in the piping is less than 150°F) when only one pipe passes through the penetration.
2. Sleeved - These penetrations have a sleeve around the outside of the piping. Sleeved penetrations are used for all multiple piping systems passing through one penetration and for all thermally hot (over 150°F) piping systems, both single and multiple. Typical piping penetrations are shown in Figure 15.5-10.

The main steam and feedwater penetrations are provided with adequate space between the piping and the sleeve for the necessary pipe insulation, and for a pipe coil outside the insulation through which component cooling water is circulated. This cooling coil reduces the temperature of the sleeve and prevents any excessive heating of the concrete in contact with the sleeve. All welded seams subjected to containment pressure are leaktested by introducing air through each test boss. In addition, the sleeve end is drilled and tapped, as shown in the details, so that any leakage between pipe wall and sleeve end can be detected during periodic containment leakage testing.

The liquid and gas pipe penetration assemblies, in nearly all instances, consist of more than one pipe inside the penetration sleeve. The diameter of the sleeve depends on the number and size of the pipes installed in a given penetration. Each of these penetrations was tested with air using the same procedure as that used for the steam and feedwater penetrations.

A 20-inch o.d. fuel transfer tube penetration is provided for fuel transfer between the refueling canal in the containment structure and the spent-fuel pool in the fuel building. The penetration consists of a 20-inch stainless steel pipe installed inside a 26-inch pipe, as shown in detail in Figure 15.5-10, Sheet 1. The inner pipe acts as the transfer tube, and connects the containment refueling canal with the spent-fuel pool. The outer pipe is welded to the containment liner, and provision is made, by use of a special seal ring, for air leak testing of all welds essential to the integrity of the penetration. Bellows expansion joints are provided on the outer pipe to compensate for any differential movement between the two pipes.

The equipment hatch is a 14-ft. 6-in. single closure penetration. The equipment hatch cover is mounted inside the containment structure and is double gasketed with a leakage test tap between the o-rings. The equipment hatch cover is provided with a hoist with two point suspension and a sliding rail for storage. A positive locking device is furnished to prevent circular swing. The equipment hatch was designed, fabricated, and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class B. A removable concrete tornado missile shield protects the equipment hatch and acts as equivalent shielding.

The equipment hatch opening is analyzed in two basic steps, using the actual space curve shape. In the first step, it is assumed that the pattern of stress concentration at the junction of the cylinder and the ring beam is the same as if the cylinder were of infinite radius and the ring and the cylinder were in the same plane; that is, the cylinder wall is assumed to be a flat plate. The forces are imposed on this flat plate at such a distance from the opening that they are not influenced by the opening. These forces are membrane meridional (vertical) loads, circumferential (hoop) loads, and tangential shear loads. An outward longitudinal force is delivered to the inside face of the ring beam by a bearing plate which is welded to the liner plate. This force is caused by incident pressure acting on the hatch.

The first step of analysis is performed by using the Stone & Webster Shell I computer program, which is based on general first-order linear plate theory modified by Sanders. This program is developed from a numerical analysis of shells of revolution as published by Bernard Budiansky and Peter Radkowski in the AIAA Journal, Vol. 1, No. 8, August 1963.

In the second step, the ring is isolated and analyzed, taking into account its actual geometry (curved in two planes). The loads imposed on the ring beam have been obtained at the junction of the ring and normal shell in the first step, plus the incident pressure loads and temperature effects on the ring surface.

The second step of the analysis is performed by means of the Stone & Webster computer program, *Reinforcing Opening in a Cylindrical Structure.* This program analyses structures curved in space about two axes. The loads imposed on the ring are the membrane forces at the juncture of the thickened ring and the normal shell, as obtained from the first step, and a modified incident pressure acting on the ring beam and hatch cover.

The analysis of the isolated ring is based on the theory of curved beams, as demonstrated in Seely and Smith, *Advanced Mechanics of Materials.* Although the theory in this textbook is confined to the one-dimensional, curved beam, the assumptions set forth are extended to the two-dimensional case. These assumptions permit a simplified calculation of the stresses and deformations.

The ring, loaded in two planes, is statically indeterminate to the sixth degree. The analysis for the ring in space consists of cutting the ring, imposing six unknown loads at the cut section, and solving for the six unknown forces by equating differential deflections and rotations on either side of the cut to zero. The six unknown forces are: direct force, a torsional moment, a transverse shear, a radial shear, and bending moments about two axes. The curvature of the ring is considered in obtaining the bending moment strains and effects on total strain energy.

An emergency airlock is provided through the equipment hatch for emergency access to the containment. The airlock is flanged to the outside of the equipment hatch cover utilizing a double o-ring seal, and has an outside diameter of 6 ft 0 in., and a length of 12 ft 8.50 in. A 30-inch-diameter door is located at each end of the air lock. The air lock doors, which swing toward the center of the containment, are interlocked so that one door cannot be operated unless the other is closed. These are mechanical interlocks, and provisions have been made for deliberate violation of the interlock by use of a special tool. This tool shall be kept under administrative control.

Each door is equipped with a valve for equalizing the pressure across the door. At no time can the equalizing valves on both doors be open simultaneously, and in no case can an equalizing valve be open on one door while the other is operating.

The operations required at each station for engagement or release of the interlocks, for operation of the equalizing valve, and for opening or closing the door, are accomplished by rotation of a single handwheel. Provisions have been made to allow operation of the outer door from inside the containment and the inner door from outside the containment, in addition to local operation.

Both doors are designed to withstand the containment test pressure of 52 psig. Each door is also designed to withstand 8.0 psia pressure in the containment structure with full atmospheric pressure outside. The interior door is provided with an additional securing device to facilitate testing the air lock to the maximum test pressure when the containment structure is at 8.0 psia.

All shafts penetrating the door or bulkhead have double packing. A blind flanged emergency air port is provided on the air lock outside containment. A light is provided inside the air lock and is powered near the air lock for communication.

A track is provided for emergency air lock removal via a cart. The track consists of two continuously supported rails that extend through the equipment hatch barrel onto the platform. Chicago Bridge and Iron Company designed and installed the track inside the equipment hatch barrel, and Stone & Webster designed the identical mating rails on the platform.

The tornado missile shield outside the containment equipment hatch has been modified to provide a labyrinth passage to the air lock. The missile shield slabs are fastened to the equipment hatch platform, which consequently has been modified. The equipment hatch platform has sufficient structural steel to withstand tornado wind loads on the attached missile shields.

The design, fabrication, and testing of the emergency air lock was performed by Chicago Bridge and Iron Company according to the ASME Code Section III, Subsection NE, 1971 Edition through the Winter 1972 Addenda. Welder procedures and performance qualifications were controlled under ASME Code Section IX.

The personnel hatch is a 7 ft. 0 in. i.d. double closure penetration as shown in Figure 15.5-11. Each closure head is hinged, double gasketed with a leakage test tap between the o-rings. Both doors are interlocked so that in the event one door is open, the other cannot be actuated. Both doors are furnished with a pressure equalizing connection. The equalizing valves are manually operated by persons entering or leaving the personnel hatch. The personnel hatch was designed, fabricated and stamped in accordance with the ASME Boiler and Pressure Vessel

Code, Section III, Class B. The personnel hatch is externally protected from tornado missiles by concrete shield walls and roof.

An 18-inch-diameter manway on the inner door of the personnel airlock is also provided for emergency egress from the containment. A positive locking device prevents inadvertent opening of the emergency manway. Manway position indication is provided in the control room. Alarm indication is also provided in the control room, and on the control panels on either side of the personnel airlock inner door, to indicate whenever the manway locking bar is not in the proper position to prevent inadvertent opening of the manway.

Material for the liner and penetrations is carbon steel plates conforming to ASTM A442, Grade 60, which has a specified minimum tensile strength of 60,000 psi, a minimum guaranteed yield strength of 32,000 psi, and a guaranteed minimum elongation of 25% in a standard 2-in. specimen. The liner has sufficient ductility to tolerate local deformation without rupture. This material has a nil ductility transition temperature of -20°F, which is 80°F below the normal minimum shutdown temperature given in Section 5.4.1.

Steel items, except backing plates and anchors, gas testing channels, equipment hatch bolts, and equipment hatch nuts are made to fine grain practice and normalized. In addition, steel items other than the above have passed NDT tests performed in accordance with the following:

1. Material 5/8 inch and thicker was tested by the Drop Weight Test method in accordance with ASTM E 208.
2. Material less than 5/8 inch thick was tested by the Drop Weight Tear Test method as developed by the U.S. Naval Research Laboratory (NRL Report 6300).
3. Material 5/8 inch and thicker has an NDT no higher than -20°F.

The liner plates were ordered to conform to standard mill practice with regard to thickness tolerances. Therefore, the 3/8-inch-thick cylindrical shell liner plate ranges in thickness from 0.365 inches to 0.406 inches. The 0.50-inch-thick hemispherical dome liner plate ranges in thickness from 0.490 inches to 0.535 inches, and the 0.25-inch-thick flat base liner plate ranges in thickness from 0.240 inches to 0.285 inches.

Physical and chemical properties of materials used in the construction of the containment liner, weldability tests, and liner thickness were checked by the Stone & Webster Field Quality Control Organization on a random sampling basis.

All welding procedures and tests required in Section IX of the ASME Boiler and Pressure Vessel Code for Welding Qualifications were adhered to in the selection of weld rod material, weld rod flux, heat treatment, and qualification of the welding procedures and the performance of welding machines and welding operators engaged in the construction of the containment liner. The welding qualification included 180-degree bend tests of weld material. These procedures ensure that the ductility of welded seams was comparable to the ductility of the containment liner plate material.

Section III of the ASME Boiler and Pressure Vessel Code for Nuclear Vessels was used as a guide in the selection of materials.

Erection of the steel liner followed completion of the concrete mat. The 3/8-inch-thick steel wall liner was erected to approximately Elevation +60 ft. The 0.25-inch-thick mat liner plate was installed on top of the concrete foundation mat during this period. On completion of the wall liner to Elevation +60 ft. and completion of the mat liner, all welds were checked for compliance with the approved weld inspection and gas test requirements. Work on the liner was then stopped until the containment interior concrete structure was completed, the polar crane was erected, and the concrete containment wall was completed to ground grade (Elevation 26 ft. 6 in.).

The 3/8-inch-thick steel wall liner was erected from Elevation +60 ft. to Elevation +92 ft. 6 in., and the containment liner completed with the construction of the 0.50-inch-thick steel dome liner. A-1 welds were inspected and gas-tested for compliance with the weld requirements.

The reinforced concrete wall, above ground grade, was completed, following as closely as practical the construction of the wall liner.

The reinforced concrete dome was constructed upon completion of the dome liner.

The steel wall liner was braced internally and locally with temporary bracing to prevent distortion during concrete placement. The exterior concrete forms were supported from the placed concrete and tied to form a tension ring.

Cantilevered steel strongbacks were used in the construction of the concrete dome to support the steel dome liner against deformation due to the weight of reinforcing steel formwork and wet concrete. Strongbacks were cantilevered from the completed concrete of the dome.

The containment liner is not a coded pressure vessel, so there was no section of the ASME Boiler and Pressure Vessel Code for Nuclear Vessels directly applicable to its design and construction. However, to ensure that good engineering practices were followed, certain portions of Section III of the Code were reviewed for suggested guidance as to design and construction practices that should be incorporated in the liner specifications. Those sections reviewed for information were:

- N-511 Certification of Materials by Vessel Manufacturer
- N-512 Material Identification
- N-513 Examination During Fabrication
- N-514 Repair of Material by Welding
- N-515 Forming Shell Sections and Heads
- N-518 Attachments

- N-519 Cutting Plates and Other Products
- N-521 Welding Processes
- N-522 Welding Qualifications and Weld Records
- N-523 Precautions for Welding
- N-524 Assembly
- N-526 Finished Longitudinal and Circumferential Joints
- N-527 Miscellaneous Welding Requirements
- N-528 Repair of Weld Defects
- N-531 Preheating
- N-541 Modification of Section IX - Welding Procedure Qualification Requirements
- N-611 Inspection, General
- N-612 Qualification of Inspectors, Engineering Specialists, and Inspection Agencies
- N-613 Access for Inspector
- N-614 Inspection of Materials
- N-615 Marking on Plates and Other Material
- N-616 Final Inspection
- N-620 Inspection of Welding
- N-622 Check of Welder and Welding Operator Performance Qualifications
- N-623 Check of Nondestructive Examination Methods
- N-625 Ultrasonic Examination of Welded Joints
- N-626 Magnetic Particle Examination
- N-627 Liquid Penetrant Examination
- N-713 Pneumatic Test
- N-714 Pressure Test Gauges

The liner attachments are Nelson concrete anchors, welded on a triangular pattern to the wall and dome liner, and cast in the containment concrete as the concrete was poured against the liner. The attachment spacing was determined by the procedure (Reference 6) set forth for buckling of a cylindrical shell under combined axial and uniform lateral pressure where each attachment constitutes a buckling wave nodal point and was so spaced that the critical buckling stress will take place in plastic range of the liner material. The liner dome was treated in a similar manner. Maximum variation from the correct stud location, where relocation was necessary to avoid an obstruction, did not exceed 1.50 inches. The bottom mat liner was covered with 1.50- to 2-foot-thick reinforced concrete slab to protect it from both pressure and temperature loadings, so that it will remain virtually unstressed.

All penetrations are anchored into the concrete containment structure wall with a loading resistance level greater than the plastic strength of the penetration pipe. Openings in the liner plate are reinforced with reinforcing plate, and/or collar, sized to develop the full relief of the liner plate. The stress around each reinforced opening was analyzed in accordance with the appropriate procedure (Reference 7).

Departure from the original specified out-of-roundness tolerance of the reactor containment liners was necessary due to erection difficulties. Attempts were made to obtain the specified tolerance by means of an adjustable ring girder and supplementary anchorage to the cofferdam. As work progressed above the cofferdam level, it was found that it was impractical to obtain the specified liner tolerance.

A thorough review was made of the necessity for this close tolerance, and it was found unnecessarily restrictive.

The liner shell and dome are studded to the concrete and the plate is essentially plane within an equilateral triangle, 12 inches at the base and bounded by studs at the apexes of the triangle. The response of each individual triangular element to its own particular loading system establishes the adequacy of the structure as a whole. Therefore, actual roundness of the shell has no effect on liner performance.

The following revised out-of-roundness tolerances were adopted after a thorough review of the problem.

1. The out-of-roundness tolerance shall not exceed plus or minus 3 inches from the true radius.
2. The maximum plus or minus deviation from a true circular form shall not deviate more than 0.25 inches from a straight line in any 14-inch space in any plane in any location on the liner.

The revised out-of-roundness tolerances have no adverse effect on the buckling strength of the liner, and ensure that plate buckling between studs will not occur in the elastic range.

The adjustable ring girder was found to be of limited value during the erection of the liner, due to the many liner penetrations and the stiffness of the liner shell. Therefore, the ring girder was used for rounding the shell only in areas where its application was found advantageous by the liner fabricator.

15.5.1.9 **Materials**

See Sections 15.5.2.2, 15.5.2.3, and 15.5.2.4 for descriptions of the construction materials used for the Reactor Pressure Vessel Head Replacement Project.

15.5.1.9.1 Concrete

The description of concrete materials is given in Section 15.3.1.

See Section 15.5.2.4 for the description of the concrete used for the Reactor Pressure Vessel Head Replacement Project.

15.5.1.9.2 Porous Concrete

Porous concrete is used under the base mat to provide drainage for the containment structure. The type of concrete is formed by the omission of the fine aggregate from a standard structural concrete mix. The mix was designed to have a 28-day compressive strength greater than 1000 psi.

Water porosity tests were performed earlier in an independent laboratory for porous concrete, using 6-inch by 12-inch cylinders prepared in the laboratory by compacting the material in three layers with standard tamping rods. A varying number of strokes, ranging from 10 to 40 for each layer, were used for different cylinders. After the concrete test cylinders had been properly cured, the amount of water that would flow through the 12-inch length of specimen during a three-minute period with a constant head of 4 inches of water above the top of each cylinder was determined. Results indicated water porosities of from 28 to 47 gpm/ft^2, depending upon the amount of compaction and resulting density of the cylinders.

The porosity determined by the laboratory tests indicated that the four-inch porous concrete layer under the base mat provides adequate drainage, since the leakage through the membrane waterproofing of the container would be minor. This layer serves as the collection means for the seepage removal system in the mat, described in Section 15.5.1.3.

15.5.1.9.3 Reinforcing Steel

Special large-size reinforcing bars, No. 14 and No. 18, used in the construction of the reactor containment structure, are steel of 50,000 psi minimum yield point, conforming to Grade 40 of the *Standard Specification for Deformed Billet-Steel Bars for Concrete Reinforcement,* ASTM A615 as modified to meet the following chemical and physical requirements:

- Carbon 0.35% maximum
- Manganese 1.25% maximum

• Silicon	0.15 to 0.25%
• Phosphorus	0.05% maximum
• Sulphur	0.05% maximum
• Minimum yield strength	50,000 psi.
• Elongation	16% minimum in a 2-inch test sample
• Tensile strength	70,000 to 90,000 psi

For these special chemistry bars, all ingots were identified and all billets were stamped with identifying heat numbers. All bundles of bars were tagged with the heat number as they came off the rolling mill. A special stamp marking was rolled into all bars conforming to this special chemistry, to identify them as processing the chemical and mechanical qualities specified.

See Section 15.5.2.3 for the description of the reinforcing steel used for the Reactor Pressure Vessel Head Replacement Project.

The engineers' quality assurance inspectors witnessed, on a random basis, the pouring of the heats and the physical and chemical tests performed by the fabricator. Bars containing inclusions, or failing to conform to the required chemical and physical requirements, were rejected.

One 12-inch-long test sample was furnished to the engineers from a finished bar from each heat of the special chemistry rebars, to permit independent verification of physical and chemical analysis tests by the engineers.

Test specimens for the special chemistry rebars conformed to Section 10.1.1 of ASTM A615 and were Standard 0.505-inch-diameter specimens with 2-inch gauge length. Rate of loadings was such that the tension-tested sample was brought to the yield point in not less than 2 minutes.

For containment structure, reinforcing steel, consisting of No. 11 bars and smaller, is of 40,000 psi minimum yield point, conforming to Grade 40 of the *Standard Specification for Deformed Billet-Steel for Concrete Reinforcement,* ASTM A615.

The reinforcing steel for structures other than the containment structures is described in Section 15.4.3.

15.5.1.9.4 Cadweld Splices

Cadweld reinforcing steel splices, Type "T" full tension splices, as manufactured by Erico Products, Inc., Cleveland, Ohio, were used to splice 50,000 psi minimum yield point reinforcing bar sizes No. 14 and No. 18. These splices, including the sleeves, develop tensile strengths not less than 90% of the minimum ultimate strength of the reinforcing bar. The average value of two or more successive splices develop at least the minimum ultimate strength of the rebar. Information for splices other than No. 14 and No. 18 reinforcing bars is given in Section 15.4.3.

See Section 15.5.2.3 for the description of Cadwelds, including operator qualification and tensile testing, used for the Reactor Pressure Vessel Head Replacement Project.

15.5.1.9.5 Waterproofing Membrane

The waterproofing membrane is a flexible polyvinyl chloride sheet having a minimum thickness of 40 mils. Associated adhesives and tapes consist of the membrane manufacturer's recommended material for the application conditions.

15.5.1.10 **Construction Procedures and Practices**

After performing the general excavation described in Section 15.4.4, two 149-ft. 5.25-in.-diameter cofferdams were constructed, one for each reactor. The cofferdams consist of interlocking steel sheet piles supported by a system of heavily reinforced concrete internal ring wales. The top of the sheet piles is at Elevation +10 ft. and tip grade is at Elevation -48 ft. The interior of the cofferdams was excavated to approximately Elevation -41 ft. Seepage drains were then driven through a 12-inch layer of crushed stone placed in the bottom of the excavation, as described in Section 15.5.1.3.

A 2-inch-thick concrete leveling slab was placed over the crushed stone and 40-mil-thick vinyl waterproof membrane placed over this concrete. A 4-inch layer of porous concrete was then placed over the membrane to protect the membrane and to serve as an internal drainage system, as described in Section 15.5.1.12.

Porous concrete was also placed around the sides of the cofferdam to fill the space between the cofferdam and the edge of the concrete mat, and to provide a form for the mat concrete. The waterproof membrane was extended vertically in this area, and protected by concrete block.

The reinforcing steel, steel bridging bars as described in Section 15.5.1.8, and other miscellaneous steel inserts required in the containment mat were placed, and the concrete poured. The mat was constructed in six sections.

The 3/8-inch-thick steel wall liner was then erected to Elevation +60 ft on the containment wall. The steel mat liner plates were installed on top of the concrete mat. All welds were checked for compliance with the approved weld inspection and gas test requirements. The containment interior concrete structure was then built on the mat liner. On completion of the interior concrete structure, the polar crane was erected.

The exterior containment concrete wall was constructed to approximately Elevation 24 ft. 6 in. during the construction of the interior concrete. On completion of the concrete substructure, a vinyl waterproof membrane was attached to the exterior concrete surface with adhesives. The membrane completely encloses the containment structure below grade.

The space between the cofferdam and the containment structure was then backfilled with crushed stone compacted in 6-inch layers. A 2-foot-thick layer of compacted impervious fill was placed at Elevation -4.0 ft. to seal the area and to minimize the amount of ground water seeping into the area.

The liner was then completed and finished with the construction of the 0.50-inch-thick steel dome, with all welds inspected and gas-tested. The steel dome liner was supported during erection with open web steel trusses.

See Section 15.5.2.2 for the description of the restoration of the steel liner during the Reactor Pressure Vessel Head Replacement Project.

The reinforced concrete wall above ground grade was completed, following as closely as practical the construction of the wall liner.

The completed steel wall liner was braced internally and locally with temporary bracing to prevent distortion during concrete placement. The exterior concrete forms were supported from the preceding concrete.

Cantilevered steel strongbacks were used in the construction of the concrete dome to support the steel dome liner, reinforcing steel, formwork, and wet concrete against deformation. Strongbacks were cantilevered from the completed concrete of the wall or the dome.

Careful inspection of the dome was maintained during concrete placing and until the concrete had definitely taken initial set. Concrete buckets used during the first two lifts of the dome were limited to 2 yd^3 in size. Bucket sizes were increased after the second lift had set, when placing results of these lifts were satisfactory and warranted such a move.

Concrete in the wall and dome of the containment structure was poured in uniform 6-foot lifts around the entire circumference. Each lift was constructed in approximately 18-inch layers.

See Section 15.5.2.4 for the description of the concrete used for the Reactor Pressure Vessel Head Replacement Project.

Concrete forms were used on the exterior of the concrete dome to a line 50 degrees above the horizontal. The permanent steel liner served as the inner form for pouring concrete. For the area where exterior forms were used, the concrete points were in horizontal planes. Above the 50 degree line, the remainder of the dome concrete was poured as one lift.

Particular care was taken to check the special markings of the No. 14 and No. 18, 50,000-psi minimum-yield rebars for the containment structure.

See Section 15.5.2.3 for the description of welded splices and Cadwelds, including operator qualification and tensile testing, used for the Reactor Pressure Vessel Head Replacement Project.

Welded splices conform to *Recommended Practices for Welding Reinforcing Steel, Metal Inserts, and Connections, in Reinforced Concrete Construction,* AWS D12.1. Bars spliced by metallic arc welding develop not less than 90% of the minimum ultimate strength of the reinforcing bar, and the average of two or more successive splices develop at least the minimum ultimate strength of the bar.

Structural ductility was maintained by staggering critical splices where possible. Full scale pressure tests conducted in May 1967, on a recently completed concrete containment structure (Reference 8) in which similar Cadweld splices and welded splices were used, showed no stress concentrations or lack of structural ductility. Locations of splice groups were not discernible from inspection of the test crack patterns.

All Cadweld Process Type "T" joints were visually inspected. The visual inspection included inspection of the ends of the bars for dryness and cleanliness prior to fitting the sleeve over the ends. It also included inspection of the completed splice for properly filled joints to ensure that filler metal was visible at both ends of the sleeve and at the top hole in the center of the sleeve. Randomly selected splices were removed from the structure and strength-tested for compliance with the specification. Joints that did not meet all these inspection criteria were replaced.

Randomly selected Cadweld Type "T" splices were removed from the containment structure and tensile-tested for compliance with the specifications, in accordance with the following schedule:

1. One out of first 10 splices.
2. Three of next 100 splices.
3. One out of each subsequent unit of 100 splices.

Welding inspection of reinforcing bars was by quality control inspectors. Radiographic inspection, dye-penetrant inspection, magnetic-particle inspection, or other nondestructive inspection methods for welded joints was performed on a random basis under the direction of the Senior Quality Control Engineer.

All welds were visually inspected. Any cracks, porosity, or other defects were removed by chipping or grinding until sound metal was reached, and then repaired by welding. Peening was not permitted.

Completed welded splices were selected on a random basis and removed from the structure with suitable lengths of adjacent bars. These removed splices were tensile-tested for compliance with the specifications in accordance with the same schedule followed for the Cadweld Type "T" splices.

Tack welding of special chemistry rebar was not permitted.

15.5.1.11 **Missiles and Piping Rupture**

15.5.1.11.1 Interior Missiles

Most of the high-pressure piping and equipment of the primary coolant system is located within containment cubicles protected by reinforced concrete walls and floors with a minimum thickness of 2 feet. The control rod drive mechanisms are provided with a separate missile shields (reinforced concrete for Unit 1 and steel for Unit 2). These structures will terminate the flight of any conceivable missile. Openings in the charging floor required for ventilation or access are covered by steel grating, which is designed to provide adequate missile protection. Openings in cubicle walls for overpressure blowoff protection are directed in a manner that will minimize the possibility of missiles striking the containment liner. An analysis of the missile hazard has been performed and the conclusions are as follows:

> Missiles could be either concrete or steel. Because of lower density and lower strength, a concrete missile would have to be an order of magnitude heavier than a steel missile of comparable diameter and velocity for it to cause the same damage on impact with a steel shell. Also, in the context of the design-basis accident, there are more potential steel missiles and these have been studied in detail.

The most penetrating steel missile for a given mass and velocity would be rod-shaped, impacting end-on; therefore, rods of various diameters and weights have been investigated.

Missile velocities of 100 fps might be generated by rupture of a reactor coolant loop[1], and this value has been used with penetration equations developed by D. A. Davenport (Reference 9) to estimate their penetrating capability.

Table 15.5-3 summarizes the results of the analysis. Inspection of these results indicates that, except for the containment liner, at 100 fps, the required weight and dimensions for penetration of the metal thicknesses of interest are not credible for missile sizes that can be postulated within the reactor containment. The metal thicknesses shown in the table bracket the thicknesses of interest for the containment liner and piping systems. The analysis for the containment liner does not consider the added resistance to penetration afforded by the interaction between the concrete containment structure and the containment liner. This added resistance will not permit penetration by missiles of credible weight and size. Major components, such as the steam generator, have greater shell thicknesses than the values in the table, and therefore will not be penetrated by the postulated missiles.

All potential missiles were evaluated, and those that constitute a hazard to either the liner or adjacent equipment, by virtue of their velocity and/or size, are restrained by local barriers or other mechanical means.

1. As discussed in Section 15.6.2, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop piping. However, pipe ruptures of other high-energy lines are still postulated.

15.5.1.11.2 Exterior Missiles

The Surry Power Station site is approximately 12 miles from the nearest commercial airport at Newport News, Virginia, and 15 miles from Langley Air Force Base. The site is not on the normal approach path to either of these air fields.

An analysis of hypothetical aircraft accidents indicates that the most likely missile that might penetrate the reactor containment would be a turbojet rotor. Calculations show that the 2-ft. 6-in.-thick containment dome would withstand without penetration the direct impact of a 1500-lb rotor impacting at a velocity of 400 mph. The 4-ft. 6-in.-thick containment walls would withstand a similar missile impacting at a velocity of 980 mph. These velocities are considerably in excess of low-level aircraft approach speeds.

Tornado-generated missiles are discussed in Section 15.2.3, and include two potential missiles:

1. Missile equivalent to a wooden utility pole 40 feet long, 12 inches in diameter, weighing 50 lb/ft^3, and traveling in a vertical or horizontal direction at 150 mph.
2. Missile equivalent to an automobile weighing one ton, traveling at 150 mph. Neither of these missiles would penetrate the reactor containment.

15.5.1.11.3 Pipe Rupture Incident

The containment internal structure is designed to accommodate the loading due to rupture of the reactor coolant and connecting piping[1], or main steam or feedwater piping. Incident rupture was considered in only one line at a time. The support system was designed to preclude damage to or rupture of any of the lines as a result of the incident. The snubber and key systems are designed to transmit rupture thrusts from a steam generator into the containment internal structures. In determining the steam generator support reactions, the system was reduced to a dynamic model consisting of a suitable number of masses and resistance elements under impulse loading. The structural support system resilience and mass was included in the model. The dynamic problem was solved by numerical methods, using a thrust-time history as loading. Resistance, dynamic amplification of the thrust, and rebound forces were calculated versus time. Design of the support system was based upon stress levels defined in Section 15.5.1.8. The reactor vessel and support system were similarly treated.

The steam lines are strapped to the crane wall at intervals selected to prevent a whipping pipe from contacting the liner. The straps are designed so that no interference with the normal thermal expansion modes of the steam lines results.

1. As discussed in Section 15.6.2, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop piping. However, pipe ruptures of other high-energy lines are still postulated.

15.5.1.12 Ground Water Protection and Corrosion

The ground-water level external to the membrane protection of the exterior surfaces of the containment structure will be kept below the top surface of the foundation mat by pumps, as described in Section 15.5.1.3.

If water penetrates or otherwise circumvents the membrane, it drains to a layer of porous concrete directly below the mat and above the membrane. This 4-inch-thick layer of porous concrete serves as a horizontal drain under the entire structure. The porous layer is vented by two 4-inch-diameter pipes that extend from the underside of the mat into a subsurface cubicle adjacent to the outside of the containment structure. This cubicle is inside the waterproof membrane. Access is provided by a concrete shaft from ground level. The 4-inch-diameter vent pipes are installed to discharge water to the floor of the cubicle at a level three feet below the mat liner; thus, flooding of the cubicle would have to occur before any hydrostatic head would be applied to the steel liner. A water level alarm is installed in the cubicle, and pumps are used as necessary to remove the water. Vertical drainage to the base of the mat is aided by three vertical inspection shafts, and various tunnels and cubicles located adjacent to the exposed exterior face of the concrete containment wall, in which the concrete is exposed.

Cathodic protection is not provided, since adequate corrosion protection of the embedded reinforcing is otherwise provided. Research by the National Bureau of Standards and other references indicates that cathodic currents damage the bond between the reinforcing steel and concrete. This bond softening is due to the gradual concentration of sodium and potassium ions. In time, the alkali concentration becomes strong enough to attack the steel.

The surface of the steel liner in contact with concrete is not subject to corrosion because of the alkaline nature of the concrete. The interior exposed surface of the liner is protected by one coat of inorganic zinc silicate primer with one top coat of epoxy enamel. These materials were used during construction. The repair coatings currently used are selected in accordance with administrative controls. No other protective coatings or insulation are considered necessary.

15.5.1.13 Testing and Inservice Surveillance

15.5.1.13.1 General

The completed containment structure was tested for structural integrity by subjecting the structure to an air pressure test equal to 115% of the design pressure. The structure was first carefully surveyed, measured, and inspected for cracks prior to the test, and all measurements recorded. All measurements were related to an independent datum. The pressure was then raised in 10-psi increments to the 115% test pressure (52 psig) and held at that pressure for one hour. Pressure was then reduced to complete the containment liner leak rate test described in Section 5.3.

During the 48-hour period, visual examination was made of the containment exterior surface for cracks and crack patterns as well as distortion.

Visual and instrumented observations at each pressure increment were made of the containment response during the test. Crack patterns were observed and their development noted.

Temperature, barometric pressure, and weather conditions were recorded hourly during the test period.

A further detailed dimensional survey was made of the structure on completion of the tests to record recovery of the structure.

15.5.1.13.2 Test Instrumentation

Instrumentation was designed to provide control and information on containment response during the air pressure test. Measurements were made of the radial deflection of the containment wall at selected locations from the top of the mat to the spring line of the dome. Vertical deflections were measured at the top of the mat and at the top of the dome. Additional measurements were made around the equipment access hatch and in other areas where stresses were critical.

Strain gauges were attached to the steel liner to record strains at the junction with the mat liner, at mid-height, and at the spring line of the dome. Additional strain gauges were attached to the liner around the equipment access and personnel hatches.

Exterior visual observations, above grade, were obtained using engineer's scales attached to the structure and read by transits placed nearby. Transit measurements were calibrated with independent datum points. Readings obtained by this method were considered accurate to within 0.10 inch.

Exterior deformations below grade were measured by linear variable differential transducers (LVDTs) mounted in the two pits provided for this purpose. Linear variable differential transducers recorded displacements in mils, which is an accuracy in excess of that required. Linear variable differential transducers were also used to measure displacements of the concrete rings surrounding the equipment access and personnel access hatches.

Electrical strain gauge rosettes and conventional strain gauges, reading in microinches per inch, were used to monitor strains in the liner. Since major inaccuracies with this type of gauge have resulted from inadequate installation techniques, particular attention was given to the technique used.

Redundancy of instrumentation was obtained by multiplicity of points at which measurements were made, so that loss or damage to any one station was not critical.

The range of strains and deformations expected at the 45-psig test pressure was as follows:

1. Maximum vertical elongation of the structure, not more than 1.5 inches.
2. Increase in containment diameter, not more than 1.4 inches.

3. Maximum width of new cracks or increase in existing cracks, not more than 0.03 inch per crack.
4. After containment pressure was reduced to atmospheric, the residual width of new cracks or the increased width of existing cracks, not more than 0.01 inch.
5. There was no visual distortion of the liner plate.

The containment structure remained in the elastic range during the pressure test, and there was permanent distortion in the liner or in the concrete once the pressure was reduced to atmospheric or below. However, it was fully expected that there would be small residual cracks in the concrete as a result of shrinkage in the concrete.

Under the test program outlined herein, all instruments and measuring devices were installed just prior to the test, and normal care and protection was adequate. Items damaged for any reason were readily replaced at the initiation of the test.

15.5.1.13.3 Comparison of Test Results

The selection of a test pressure, which was 115% of design pressure, was based primarily on the fact that a similar reinforced concrete containment structure for Connecticut Yankee Atomic Power Plant has been tested and accepted at 115% of its design pressure; thus, a comparative case history of structural response has been created that permits valid comparison of similar design.

The selection of 115% test pressure also conforms to the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Subsection B, Requirements for Class B Vessels, paragraph N-1312(d). This relates to metal vessels that perform the same function as a reinforced concrete containment structure.

A comparison of stresses under 115% test pressure with those in the structure under incident conditions is given in Table 15.5-4. As a sensitivity analysis, the stresses associated with 125% pressure are also included. Incident stresses shown result from incident pressure, dead load, loads due to temperature effects on the steel liner, and temperature gradients through the concrete. Stresses resulting from earthquake combined with incident loads are shown separately.

Scaled load plots comparing moments, shears, tension, and deflections resulting from the structural proof test pressure with moments, shears, tension, and deflections due to the unfactored design incident conditions are shown in Figure 15.5-13. A comparison of the test load with the hypothetical incident load conditions should include a review of the load plots in Figure 15.5-2 Sheet 2. This shows the increase in moments, radial shear, hoop tension, vertical tension, and radial deflection (deformation) imposed on the structure by the incident and test load. It can be seen that the test load conditions exceed incident conditions in all cases, except that of radial deflection.

The distribution of stress varies between the structural elements under apparently similar load conditions because of the contradictory action of the containment steel liner. Under test conditions, the steel liner was in a state of biaxial tension and gave considerable assistance to the reinforcing steel, particularly to the longitudinal reinforcing. Under incident conditions, the steel liner is subjected to a point where it is restrained in compression by the reinforcing steel. This effect is greater in the dome than in the cylindrical wall, due to the increased thickness of the dome liner and the shape factor of the dome.

This also provides an additional factor of safety against ultimate failure of the structure. In the event of excessive yield in the reinforcing steel, the liner will act as a tensile membrane that would assist the reinforcing steel. This assistance would be significant, since the liner will bring a considerable reserve of energy to bear, for which design credit has not otherwise been claimed.

The test pressure of 52 psig, based on 115% design pressure, created stresses equal to or greater than the incident stresses in the following critical areas:

1. Foundation mat, where test stresses are 30 to 40% above incident conditions.
2. Large access openings, such as equipment and personnel hatches, where test stresses are comparable with incident stresses.

It is recognized that the average stress levels attained under the test conditions in the principal longitudinal and circumferential steel are below these stresses resulting from incident conditions. This is considered acceptable when the test is associated with dimensional strain measurements, when such a test provides confirmation of structural continuity and structural ductility with the concrete cracked, and when the steel is shown to carry the load in tension according to design assumptions.

An analysis of the crack pattern of the concrete under test conditions confirms stress distribution in the structure, and also reveals areas of stress concentrations. In fact, a pattern of severe local cracking would indicate structural weakness more effectively than considerations of average stress levels.

Measured response of the structure, as indicated by increase in height, diameter, and degree of recovery, together with measurements of local deformations, is extremely important in predicting structural response to incident conditions. The structural response to the test pressure is of sufficient magnitude to allow simple direct measurements of deformations without the need for high-precision methods of measurement.

In summary, it is not possible to exactly duplicate incident stress conditions with a pressure test. An increase in the test pressure above 115% would only preserve and amplify the present stress anomalies, without furnishing more meaningful data. In addition, such a test would endanger or damage the container by seriously overstressing critical areas, or it would require a container design modification directed specifically to withstand the higher pressure test without proportionate improvement in withstanding the incident condition. Modification of the containment design to obtain closer test verification of structural integrity under the test pressure would require specific redesigning for test conditions of the critical areas in the foundation mat and at the large openings. Such redesigning would not improve the capability of the containment structure to meet the incident load conditions. A design meeting both incident and test conditions is not considered practical in this type of containment design.

The 115% pressure test provided a valid test of all criteria areas with stresses equal to or greater than incident conditions; in less critical areas, the pressure test provided sufficient information to permit a reliable evaluation of the complete structural response under incident conditions.

The average anticipated crack width at the 45-psig test pressure was 0.015 inch.

A rectangular crack pattern was anticipated, with vertical cracks spaced 12 to 15 inches on centers, and horizontal cracks spaced approximately 2 feet on centers. Horizontal crack spacing was primarily controlled by the horizontal construction joints.

The average crack width was related to the anticipated increase in containment diameter, the anticipated vertical elongation of the structure, and the crack spacing. It was assumed that the total containment extension was equal to the sum of the number of cracks multiplied by the average crack width in each direction.

Maximum summer temperature and minimum winter temperature difference is approximately 95°F. Annual average temperature variation is 40°F at the station site.

During unit operation, the annual maximum thermal cycling temperature variation is approximately 45°F.

Ambient temperature variations of this magnitude, +20°F, or even the extreme +45°F, will not reopen by any significant amount the crack pattern created in the structure by the test pressure of 45 psig.

The width of thermal cycling cracks was significantly less than the 0.010 allowed for exterior members by ACI 318.

The stresses given in Table 15.5-4 are the results obtained from computer programs referred to in the following sections:

- Section 15.5.1.5 —*Numerical Analysis of Unsymmetrical Bending of Shells of Revolution*
- Section 15.5.1.4 —*Container Vessel Seismic Analysis*
- Section 15.5.1.5 —*Flat Circular Mat Foundations for Nuclear Secondary Containment Structures*
- Section 15.5.1.7 —*Nuclear Containment Structure Access Opening* - Stone & Webster Computer Program

At large openings, the stresses due to thermal load were obtained by converting the thermal effect to a pressure equivalent, as described in Section 15.5.1.5.

Since all of the shears in the wall and dome were taken by the reinforcing, the effects of shrinkage and creep are not included.

15.5.1.13.4 Inservice Surveillance Tests

Periodic structural testing of the containment structure is not planned, since it would provide no more information on the containment structure capability than that obtained from the initial test. In fact, periodic testing would cumulatively damage the concrete in the structure to the point where the test itself would be the major cause of structural deterioration.

The inservice stress and environmental conditions are not of a nature or magnitude such that any significant deterioration of the reinforcing steel or concrete could reasonably be expected, and periodic testing for structural purposes could be duplicated if at any time further tests were required. The minimum test level required to verify continued structural integrity would be no less than the 115%, or 52-psig initial test pressure.

Periodic inspection of the steel liner is accomplished by a type A leak rate test in accordance with 10 CFR 50 Appendix J. All welded joints and all penetrations of the liner are designed for periodic halogen gas testing.

In summary, no basis exists for attempting to develop structural performance information from leak rate tests conducted at moderate pressures.

15.5.2 Reactor Pressure Vessel Head Replacement Project (Applicable to Unit 1 and Unit 2)

The Reactor Pressure Vessel (RPV) Head Replacement Project created and restored a construction opening in the reactor containment structure in accordance with administrative procedures and the design control program. The opening was used to facilitate the movement of original and replacement RPV heads in and out of the reactor containment structure. The opening was restored to meet the original design bases of the containment structure.

15.5.2.1 **Codes and Specifications**

ACI 318-63 is the design code for the restored containment structure. The restored structure meets all applicable design loads and load combinations required by ACI 318-63.

Concrete placement, curing, and repair were in accordance with ACI 301-99 with the incorporation of Hot Weather Concreting per ACI 305R-99, as appropriate, or with the incorporation of Cold Weather Concreting per ACI 306.1/ACI 306R, as appropriate. The use of ACI 301-99 is in accordance with Section 2.2 of ANSI N45.2.5-74.

Concrete mix proportioning was per ACI 211.1-91 (reapproved 1997) in accordance with Table A of ANSI N45.2.5-74.

Bechtel specifications (References 11-18) address:

- reinforcing steel procurement, testing, and placement
- Cadweld reinforcing steel splices procurement, testing, and installation
- concrete mix design, testing and placement
- structural steel and materials procurement

15.5.2.2 **Liner Restoration**

The cut section of the containment liner plate was rewelded to the liner plate with a full penetration weld. The weld was tested to ensure no leakage. In addition, the full penetration weld was covered by a seal welded leak chase channel to facilitate testing.

Replacement material was purchased for the liner plate, Nelson studs, and leak chase channels. The Nelson studs, and leak chase channels were used for the reinstallation of the plate and the leak chase channel system. Reference 18 requires the liner plate material to be ASTM A-516-Grade 60 (or better), fine-grained and normalized.

15.5.2.3 **Reinforcing Steel Restoration**

The reinforcing steel bars cut during the creation of the opening were re-installed using Cadweld splices or welding, as required, in accordance with References 14, 15, and 19. Reinforcing steel bars that were damaged during the creation of the opening were repaired in accordance with References 13 and 19 or were replaced with reinforcing steel procured in accordance with Reference 12. New N18 reinforcing steel used for containment wall restoration conforms to either ASTM A615 Grade 60 and/or ASTM A706 Grade 60, and meets or exceeds the additional elongation and chemical composition requirements described in Section 15.5.1.9.3 for the containment structure existing reinforcing steel.

In lieu of the Cadweld testing protocol, described in Section 15.5.1.10, which was used during original construction, Cadweld testing was performed in accordance with Dominion’s Operational Quality Assurance Program Topical Report which includes:

- In-process testing of Cadweld splices in accordance with Subsubparagraph CC-4333.5.2 of ASME B&PVC Section III Division 2 (1995 Edition, 1996 Addenda).
- Cadweld Splice System Qualification in accordance with Subparagraph CC-4333.2 of ASME B&PVC Section III Division 2 (1995 Edition, 1996 Addenda).
- Cadweld Operator Qualification in accordance with Subparagraph CC-4333.4 of ASME B&PVC Section III Division 2 (1995 Edition, 1996 Addenda).

- Cadweld Testing Frequency in accordance with Subsubparagraph CC-4333.5.3 of ASME B&PVC Section III Division 2 (1995 Edition, 1996 Addenda).

To minimize the size of the construction opening, the Cadweld splice locations were not staggered as described in Section 15.5.1.10. Section 805 of ACI 318-63 does not require staggered Cadweld splices if the splice can develop in tension at least 125 percent of the specified yield strength of the reinforcing steel bar. The minimum acceptance criteria for the Cadweld splice testing in Reference 15 is that the minimum tensile strength of each sample tested shall be equal to or exceed 125 percent of the yield strength of the reinforcing steel bar. Also, the splicing scheme for the RPVH Replacement Project construction opening is similar to that used during the closure of the original construction opening.

15.5.2.4 **Concrete Restoration**

As discussed in Dominion's Operational Quality Assurance Program Topical Report commits to ANSI N45.2.5-74 (with clarifications) for satisfying the quality assurance requirements for installation, inspection, and testing of structural concrete during the operational phase of Surry Power Station. Section 2.2 of ANSI N45.2.5-74 requires that the installation, inspection, and test activities be performed in accordance with the latest codes. Tables A and B of ANSI N45.2.5-74 provide the requirements for the qualification and in-process testing of the concrete ingredients and concrete mix.

The concrete was replaced and the restored structure tested in accordance with ASME B&PVC Section XI, Articles IWL 4000 and IWL 5000, respectively. In accordance with the guidance of Table A of ANSI N45.2.5-74 concrete mix design is based on ACI 211.1-91 (reapproved 1997). The activities associated with placement of concrete were performed in accordance with References 11 and 17, which meet the requirements of ACI 301 and ANSI N45.2.5-74. In-process sampling, testing, and acceptance requirements for all repair material were in accordance with Table B of ANSI N45.2.5-74. Reference 11 provides the testing frequencies, sampling and testing standards, and acceptance criteria for concrete ingredients and concrete mix. The concrete had a minimum 5-day strength of 3000 psi.

The water used for the concrete mix was evaluated in accordance with the requirements of AASHTO T-26, as specified in Table A of ANSI N45.2.5-74. The water testing and acceptance criteria included in Reference 11 required that the water used during the restoration was free of harmful levels of contaminants.

The cement used in the new concrete was Type II Low Alkali (as defined in ASTM C 150).

For RPV Head Replacement Project, the restoration of the containment wall used size 57 (25 mm to 4.75 mm) coarse aggregate due to the limited size of the opening and the use of pour ports/bird mouths for concrete placement. Both fine and coarse aggregates were tested in accordance with the requirements of ANSI N45.2.5-74 to ensure acceptable physical characteristics and that they were free of harmful levels of alkali reactivity and deleterious substances (acceptance criteria are defined in ASTM C 33).

Admixtures used to modify the concrete mix properties met the requirements of ASTM standards and were used in accordance with the manufacturer's written procedures and applicable ACI standards (primarily ACI 211.1-91 (reapproved 1997) for mixing and ACI 301-99 for placement). Reference 16 prohibited the use of admixtures with chlorides. Uniformity of admixture lots was verified with Infrared Spectrophotometry in accordance with Table B of ANSI N45.2.5-74.

In its ready mix state, the new concrete had an air content of 4.5% (± 1.5%) at the point of placement. This is consistent with Table 6.3.3 of ACI 211.1-91 (reapproved 1997) for the maximum aggregate size being used in the concrete mix (1" for Size No. 57 coarse aggregate) and air-entrained concrete.

A water-reducing admixture was utilized in the concrete resulting in a maximum slump of 8 1/2 inches at point of placement based on the footnote to Table 6.3.1 of ACI 211.1-91 (reapproved 1997), which approves higher concrete slump (than the recommended 1 inch to 4 inch slump) when chemical admixtures are used provided that there are no signs of segregation or excessive bleeding.

15.5.2.5 **Post Modification Testing**

The nondestructive examination of the containment liner was in accordance with Safety Guide 19, Nondestructive Examination of Primary Containment Liners with the following changes: after vacuum box testing of the liner seam weld and installation of the channel, the channel to liner weld was tested by a static pressure test (decay test) with an acceptance criteria of zero leakage. Soap bubble testing was used to identify leakage. Leaking areas of the joint were repaired and retested. In addition, following the containment building pressure test, the channel was re-pressurized and an "as-found" LLRT, meeting ANS 56.8-1994 requirements, was performed.

Prior to placing the containment structure in-service, a containment pressure test that bounds the calculated peak containment internal pressure was performed in accordance with IWL Article 5000 of the ASME B&PVC Section XI. The surface of the replacement concrete at the temporary construction opening was examined in accordance with IWL-5250 prior to pressurization, at test pressure, and following completion of pressurization.

15.5 REFERENCES

1. G. N. Bycroft, *Forced Vibrations of a Rigid Circular Plate on a Semi-Infinite Elastic Space and on an Elastic Stratum, Philosophical Transactions*, Royal Society, London, Series A, Vol. 248, pp. 327-368.

2. Karl Terzaghi, *Evaluation of Coefficients of Subgrade Reaction, Geotechnique,* Vol. 5, pp. 297-326, 1955.

3. B. O. Hardin and W. L. Black, *Vibration Modulus of Normally Consolidated Clay, Symposium on Wave Propagation and Dynamic Properties of Soils*, University of New Mexico, 1967.

4. Stone & Webster Engineering Corporation, *Nuclear Containment Structure Access Opening*.

5. B. Budiansky and P. Radkowski, *Numerical Analysis of Unsymmetrical Bending of Shells of Revolution, AIAA Journal*, August 1963.

6. S. Gere and S. Timoshenko, *Theory of Elastic Stability*, second edition.

7. J. N. Goodier and S. Timoshenko, *Theory of Elasticity*, second edition.

8. Stone & Webster Engineering Corporation, *Report on Pressure Testing of Reactor Containment for Connecticut Yankee Atomic Power Plant, Connecticut Yankee Atomic Power Company, Haddam, Connecticut*, 1967.

9. D. A. Davenport, *Penetration of Reactor Containment Shells, Nuclear Safety*, Vol. 2, No. 2, December 1960.

10. Letter dated March 30, 1999, Serial No. 99-134, From Virginia Power to the NRC, *Supplemental Response to Generic Letter 96-06.*

11. Bechtel Specification 24841-120-C-101, Revision 6, *Technical Specification for Material Testing Services*, April 25, 2003. (Unit 1)

    Bechtel Specification 24841-120-C-101, Revision 7, *Technical Specification for Material Testing Services,* December 3, 2003. (Unit 2)

12. Bechtel Specification 24841-120-C-303, Revision 2, *Technical Specification for Purchase of Reinforcing Steel*, February 28, 2003.

13. Bechtel Specification 24841-120-C-304, Revision 2, *Technical Specification for Installation of Reinforcing Steel (Rebars)*, February 28, 2003.

14. Bechtel Specification 24841-120-C-309, Revision 1, *Technical Specification for Purchase of Cadweld Rebar Splices*, February 28, 2003.

15. Bechtel Specification 24841-120-C-310, Revision 2, *Technical Specification for Installation of Cadweld Rebar Splices*, February 28, 2003.

16. Bechtel Specification 24841-120-C-321, Revision 9, *Technical Specification for Purchase of Ready Mix Concrete Qualified as Safety-Related*, May 20, 2003.

17. Bechtel Specification 24841-120-C-322, Revision 3, *Technical Specification for Placement of Ready Mix Concrete Qualified as Safety-Related*, February 28, 2003.

18. Bechtel Specification 24841-120-C-502, Revision 3, *Technical Specification for Purchase of Non-Safety Related and Safety Related Structural Steel and Materials*, February 28, 2003.

19. *Special Processes Manual for Surry Nuclear Power Station RPV Head Replacement Project,* Revision 3, Bechtel Job 24841, May 12, 2003. (Unit 1)

20. *Special Processes Manual for Surry Nuclear Power Station RPV Head Replacement Project*, Revision 4, Bechtel Job 24841, September 25, 2003. (Unit 2)

15.5 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-1A	Machine Location: Reactor Containment, Elevation 47'- 4"
2.	11448-FM-1B	Machine Location: Reactor Containment, Elevation 18'- 4"
3.	11448-FM-1C	Machine Location: Reactor Containment, Elevation 3'- 6"
4.	11448-FM-1D	Machine Location: Reactor Containment, Elevation 27'- 7"
5.	11448-FM-1E	Machine Location: Reactor Containment; Sections “A-A”, “E-E”, & “Z-Z”
6.	11448-FM-1F	Machine Location: Reactor Containment; Sections “B-B”, “X-X”, & “Y-Y”
7.	11448-FM-5A	Arrangement: Auxiliary Building

Table 15.5-1
CONTAINMENT STRUCTURAL LOADING CRITERIA

Case	Loading Combination	Required Load Capacity of Structure
1	Operating plus DBA	= (1.0 ± 0.05)D + 1.5P + 1.0 (T + TL)
2	Operating plus DBA plus operating-basis earthquake	= (1.0 ± 0.05)D + 1.0P + 1.0 (T + TL) + 1.5E
3	Operating plus DBA plus design-basis earthquake	= (1.0 ± 0.05)D + (1.25P) + (T' + TL') + 1.0HE
4	Operating plus 1.25 DBA and 1.25 operating basis earthquake	= (1.0 ± 0.05)D + (1.25P) + (T' + TL') + 1.25E
5	Operating plus tornado loading	= (1.0 ± 0.05)D + 1.0T' + 1.0C

Legend

DBA - Design-basis accident.

C - Load due to negative pressure and horizontal wind velocity resulting from tornado and missiles. For description of tornado, refer to Section 15.2.3.

D - Dead load of structure and contents including effect of earth and hydrostatic pressures, buoyancy, ice and snow loads. To provide for variations in the assumed dead load, the coefficient for the dead load components is adjusted by ±5% as indicated in the above formulas to provide the maximum stress levels.

P - Pressure load from DBA. Pressure for containment design is 45 psig.

T - Load due to maximum temperature gradient through the concrete shell and mat based on temperature associated with 1.5 DBA pressure.

T' - Load due to maximum temperature gradient through the concrete shell and mat based on normal operating temperature.

TL - Load exerted by the exposed liner based upon temperature associated with 1.5 times DBA pressure.

TL'- Load exerted by the exposed liner based upon temperatures associated with 1.25 times DBA pressure.

T - Load due to maximum temperature gradient through the concrete shell and mat based upon temperature associates with 1.0 times DBA pressure.

TL - Load exerted by the exposed liner based upon temperature associated with 1.0 times DBA pressure.

E - Operating-basis earthquake loading. Based on a ground acceleration of 0.07g horizontally at zero period and a damping factor of 5%. For description of the operating-basis earthquake, refer to Section 2.5.

HE - Design-basis earthquake loading. Based on a ground acceleration of 0.15g horizontally at zero period and a damping factor of 10%. For description of the design-basis earthquake, refer to Section 2.5.

Note: Normal wind loadings replace earthquake loads where they exceed earthquake loadings. Normal wind or tornado loads are not considered coincident with earthquake loads.

Table 15.5-2
CAPACITY REDUCTION FACTOR FOR CONCRETE

Member	Reduction Factor
Tension and flexure	0.90
Diagonal tension, bond and anchorage	0.85

Table 15.5-3
MISSILE DIMENSIONS AND WEIGHTS REQUIRED TO PENETRATE PLATE OF VARYING THICKNESSES

Material	Missile Diameter, in.				
	1	2	3	4	5
Reactor Containment Liner Plate, 3/8 in.					
Weight, lb	21.1	42	64	85	106
Length, in.	95	48	32	24	19
4 in. Sch. 160 pipe or 0.531 in wall thickness					
Weight, lb	40.2	80.3	120.5	160.6	200.8
Length, in.	181	90	60	45	36
6 in. Sch. 160 pipe or 0.718 in. wall thickness					
Weight, lb	68.8	137.5	206.3	275.0	343.8
Length, in.	309	155	103	78	62
8 in. Sch. 160 pipe or 0.906 in. wall thickness					
Weight, lb	109.0	218.0	327.0	436.0	545.0
Length, in.	514	245	164	123	99
10 in. Sch. 160 pipe or 1.125 in. wall thickness					
Weight, lb	176.0	325.0	528.0	704.0	880.0
Length, in.	790	395	264	198	159

Table 15.5-4

COMPARISON OF STRESSES UNDER TEST PRESSURE WITH STRESSES UNDER INCIDENT CONDITIONS AND EARTHQUAKE PLUS INCIDENT CONDITIONS

	Incident Stress, psi	Earthquake Plus Incident Stress, psi	115% Test Stress psi (52 psig)	125% Test Stress psi (57 psig)
Top bars at cylinder wall	25,700	26,500	33,500	38,700
Bottom bars near mat center	26,300	30,500	29,000	38,700
Cylinder Wall (approximately mid-height)				
Circumferential reinforcing				
Inner	22,300	22,300	21,000	22,800
Outer	28,600	28,600	20,000	21,700
Longitudinal reinforcing				
Inner	19,800	21,600	9200	10,000
At base of wall	12,900	19,300	16,400	19,300
Outer	27,900	29,650	9200	10,000
Diagonal reinforcing	28,300	33,600	15,500	16,900
Diagonal (radial) shear reinforcing at base of wall	15,700	16,500	20,200	23,200
Dome				
Radial reinforcing				
Inner	28,900	28,900	14,200	15,500
Outer	34,500	34,500	13,800	15,000
Circumferential reinforcing				
Inner	28,900	28,900	14,200	15,500
Outer	34,500	34,500	13,800	15,000
Large Openings				
Equipment access hatch	32,000	33,500	31,300	33,700
Personnel access hatch	30,200	31,700	30,700	34,300

Figure 15.5-1
REACTOR CONTAINMENT WATERPROOFING

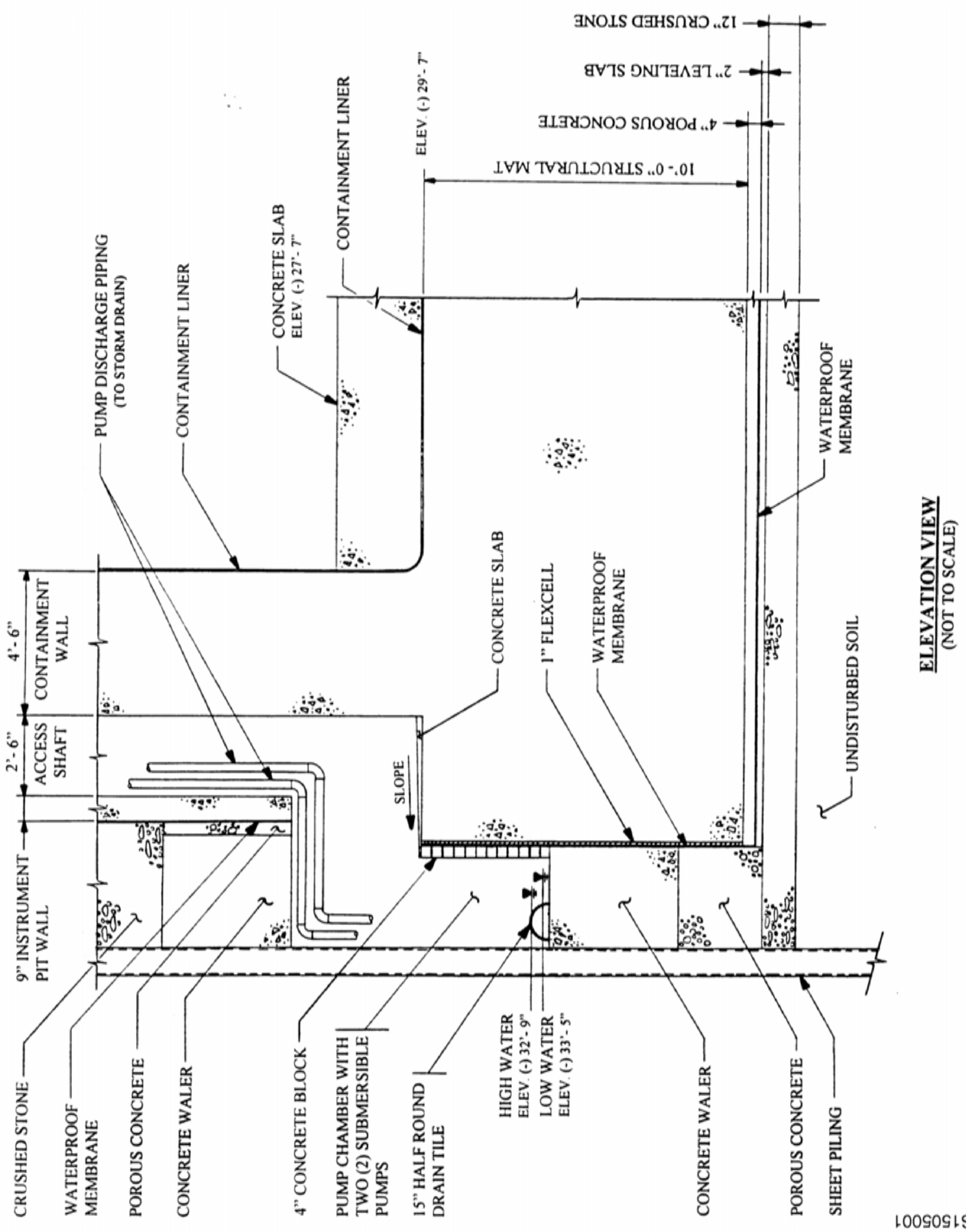


Figure 15.5-2 (SHEET 1 OF 3)
CONTAINMENT LOADING PLOT

LOADING: (1.0 + 0.05) D + 1.0 P + 1.0 (T + %L) + 1.5 E. EQ. 2

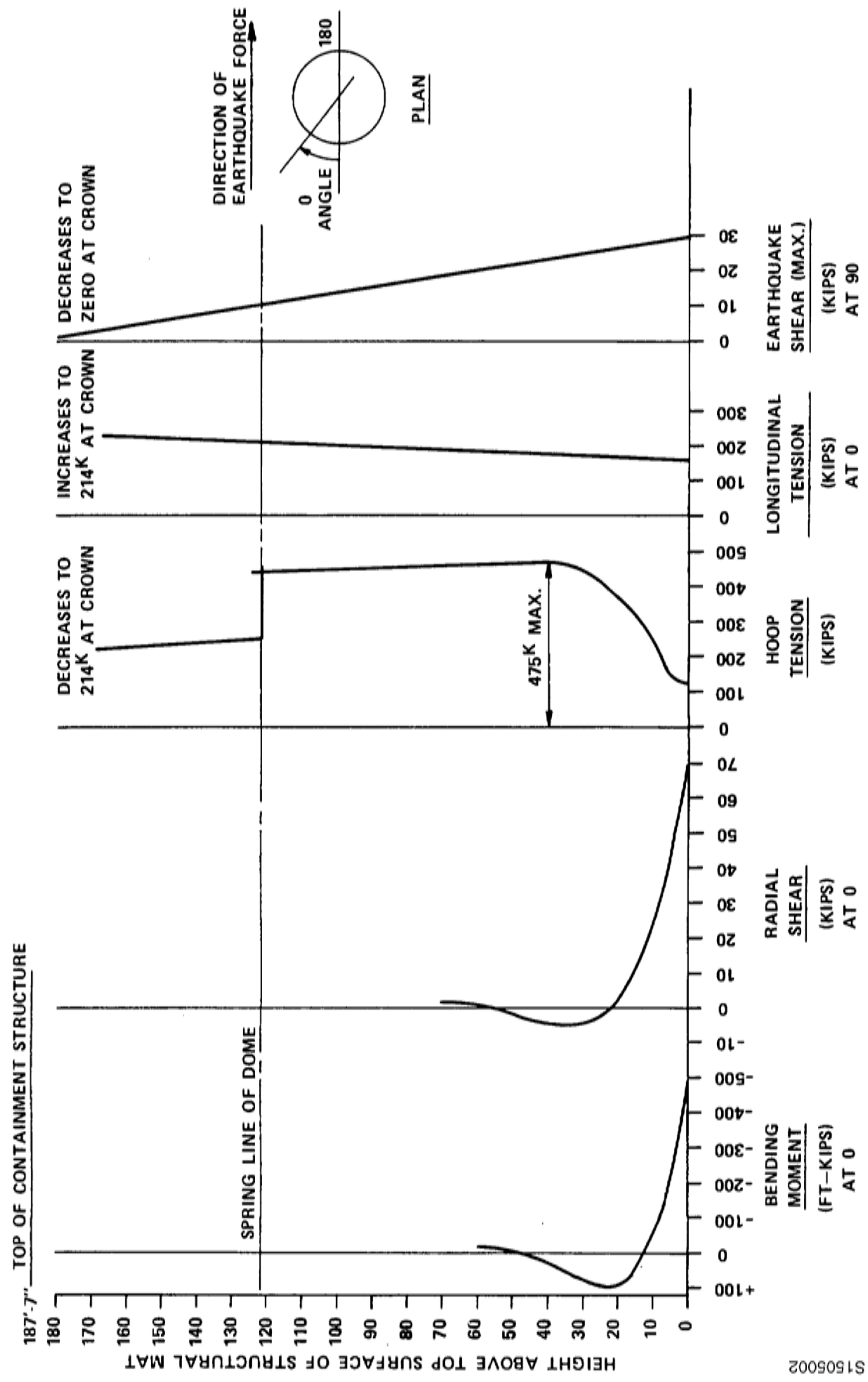


Figure 15.5-2 (SHEET 2 OF 3)
CONTAINMENT LOADING PLOT

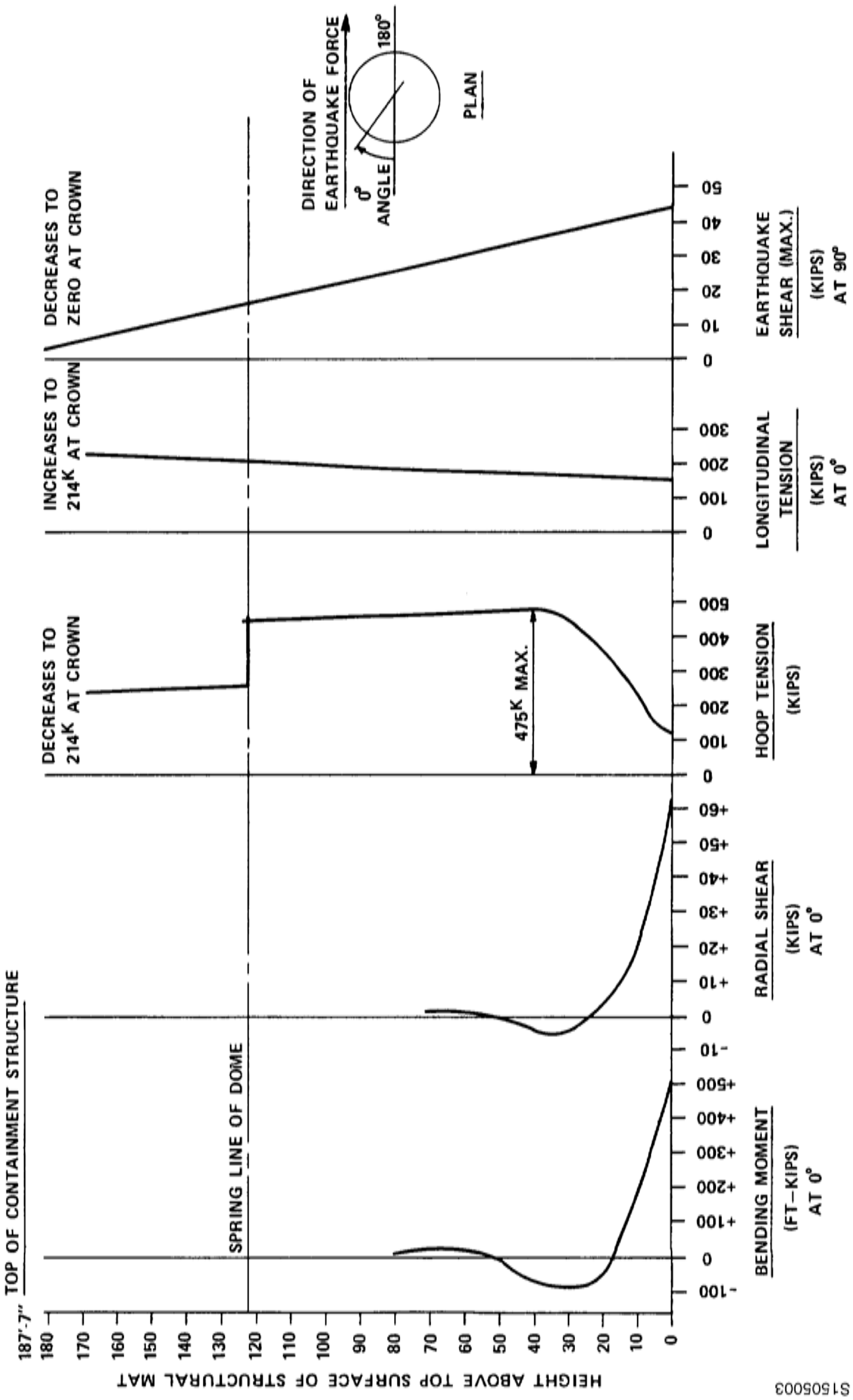


Figure 15.5-2 (SHEET 3 OF 3)
CONTAINMENT LOADING PLOT

LOADING: (1.0 ± 0.05) D + 1.5 P + 1.0 (T + TL). EQ. 1

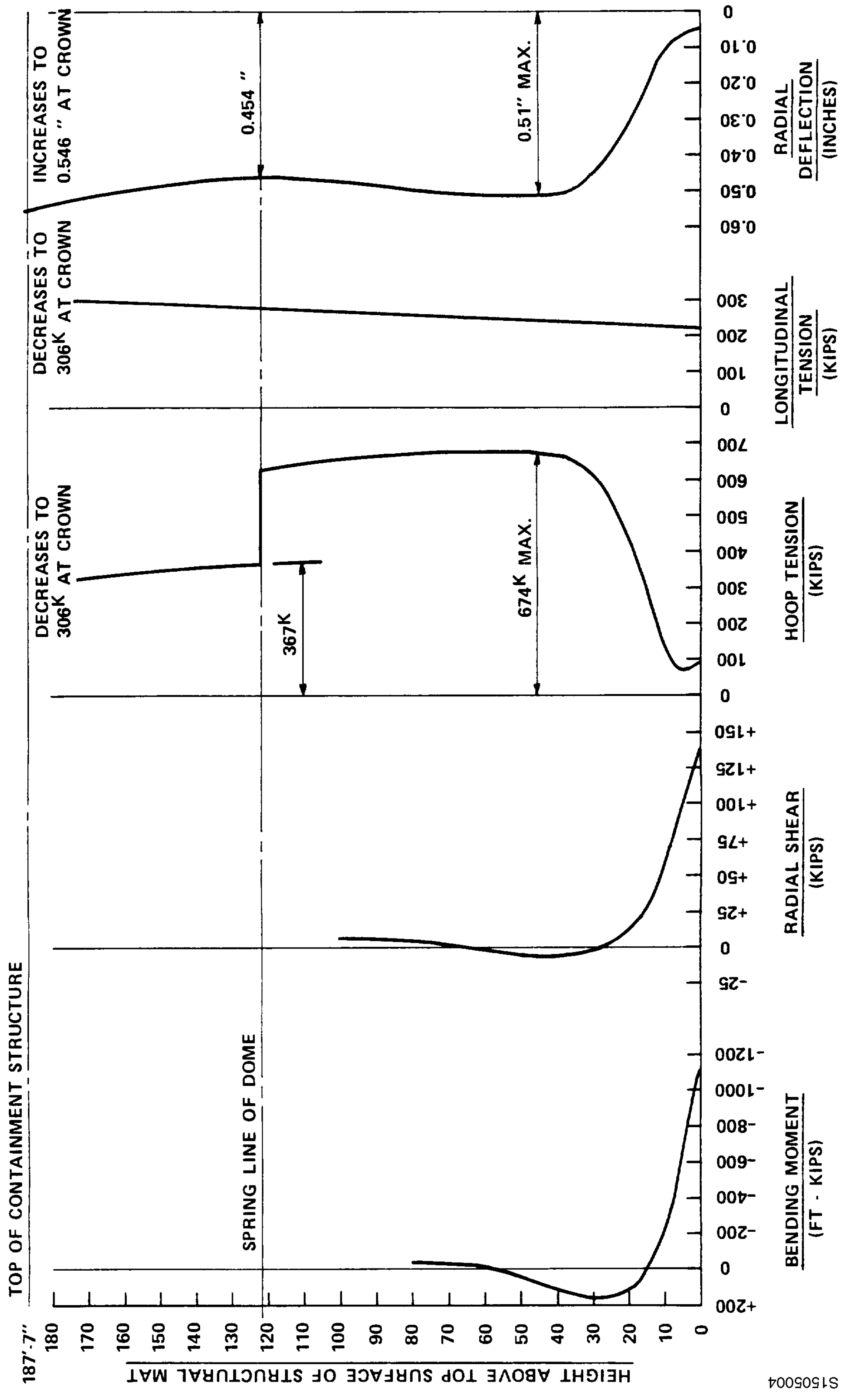


Figure 15.5-3
REINFORCING DETAILS EQUIPMENT ACCESS HATCH OPENING

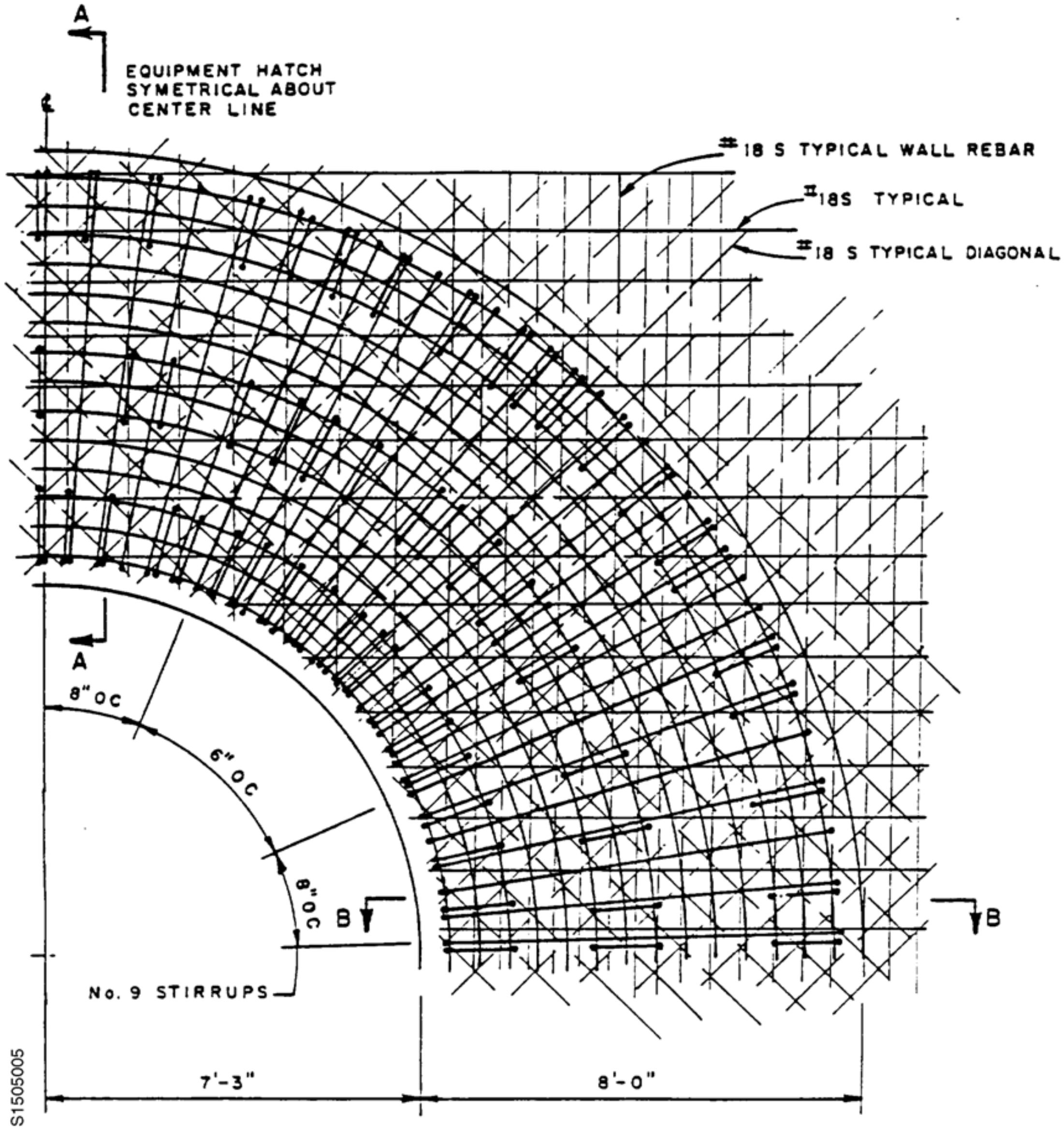


Figure 15.5-4
REINFORCING DETAILS SECTIONS THROUGH RING BEAM
EQUIPMENT ACCESS HATCH

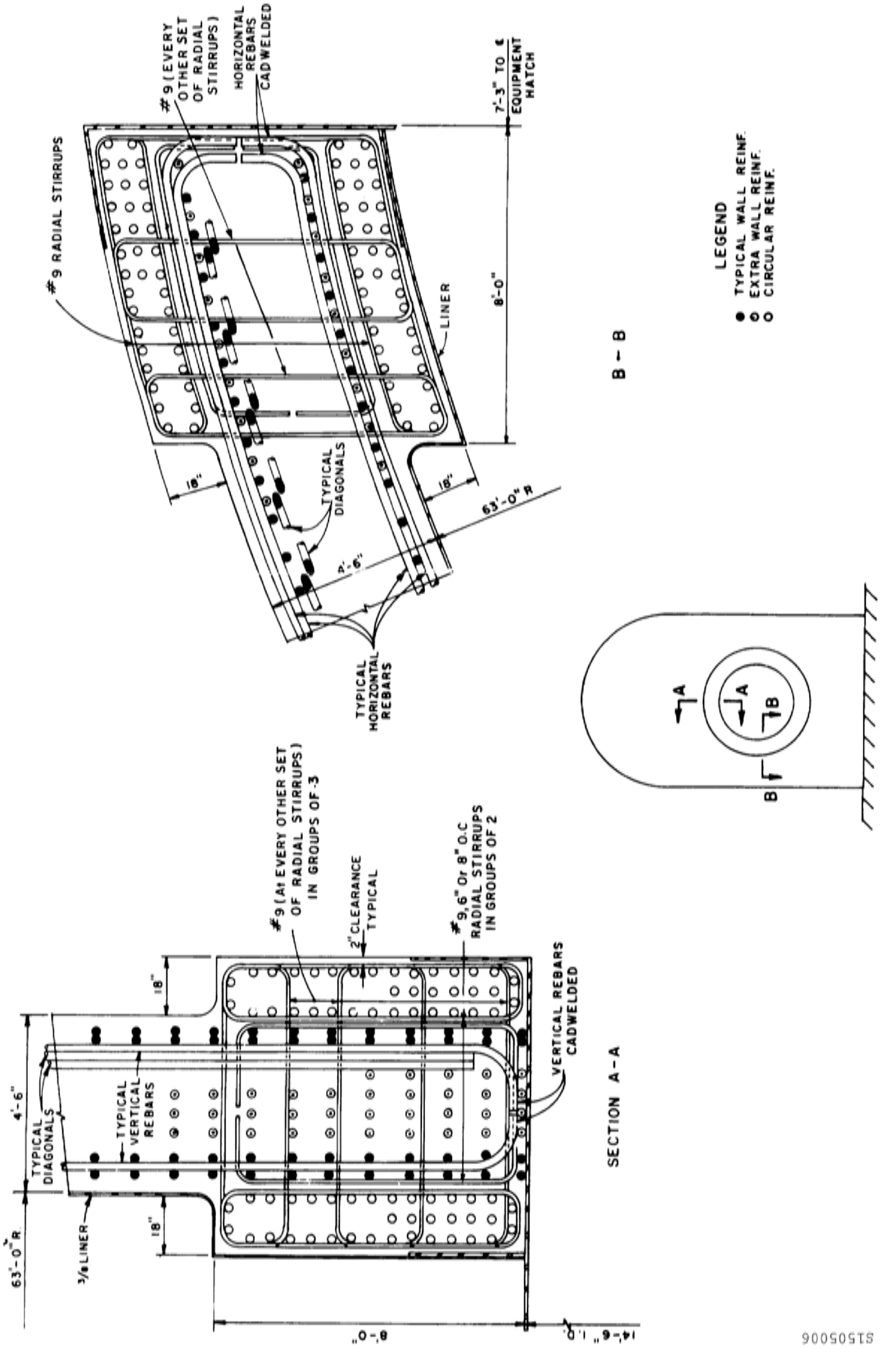
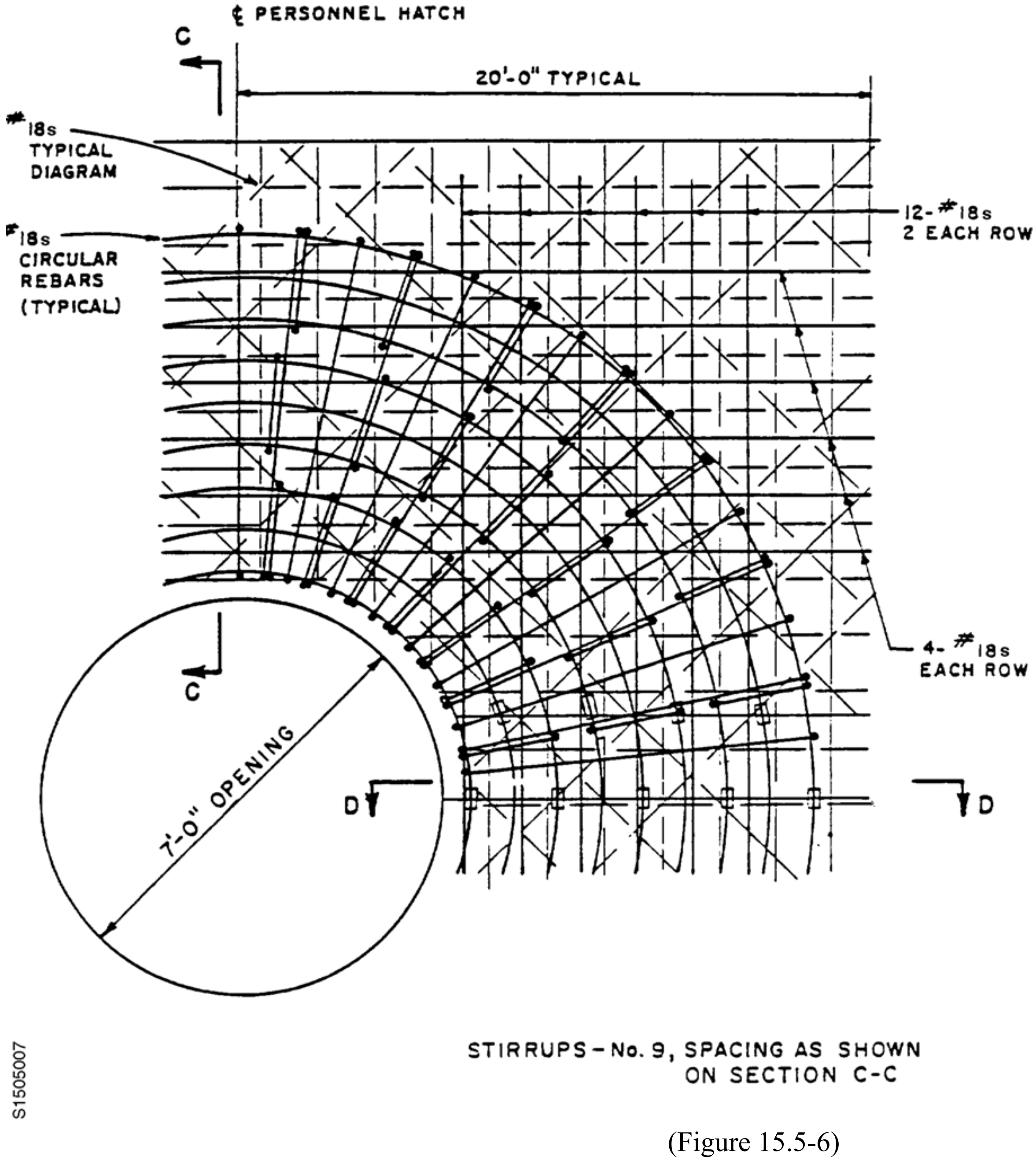


Figure 15.5-5
REINFORCING DETAILS PERSONNEL HATCH OPENING



(Figure 15.5-6)

Figure 15.5-6
REINFORCING DETAILS SECTIONS THROUGH RING BEAM PERSONNEL HATCH

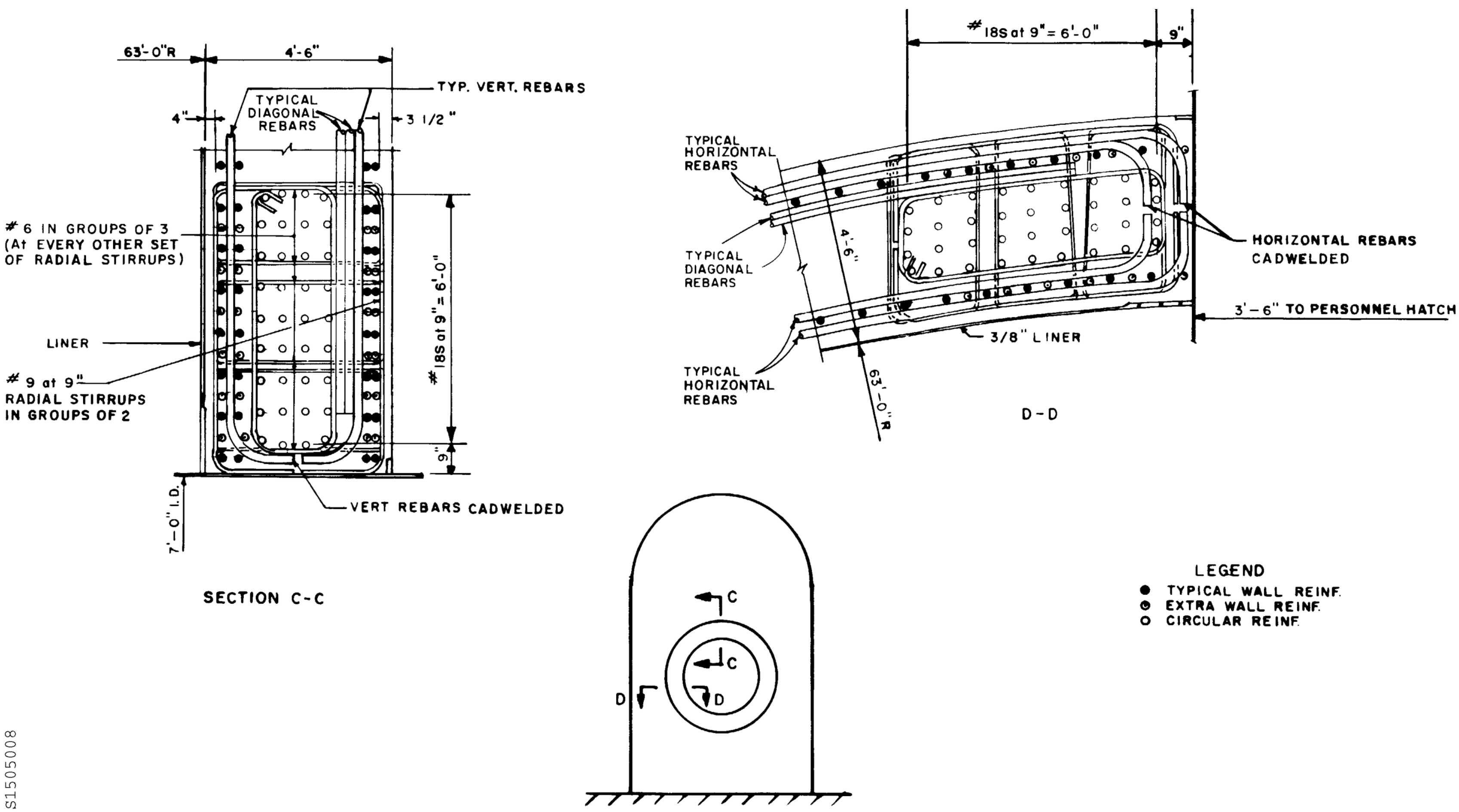


Figure 15.5-7
WALL AND MAT JOINT

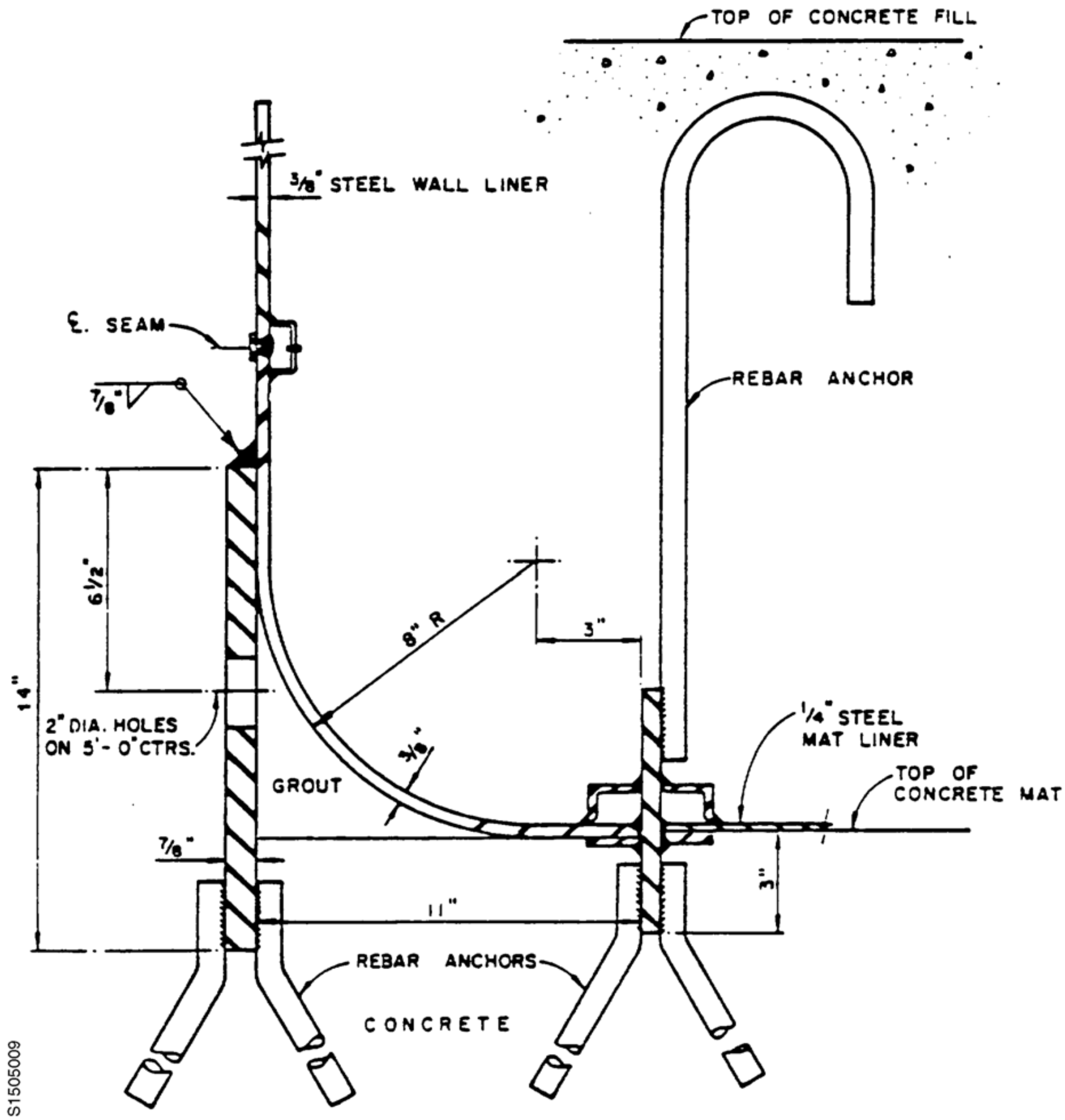
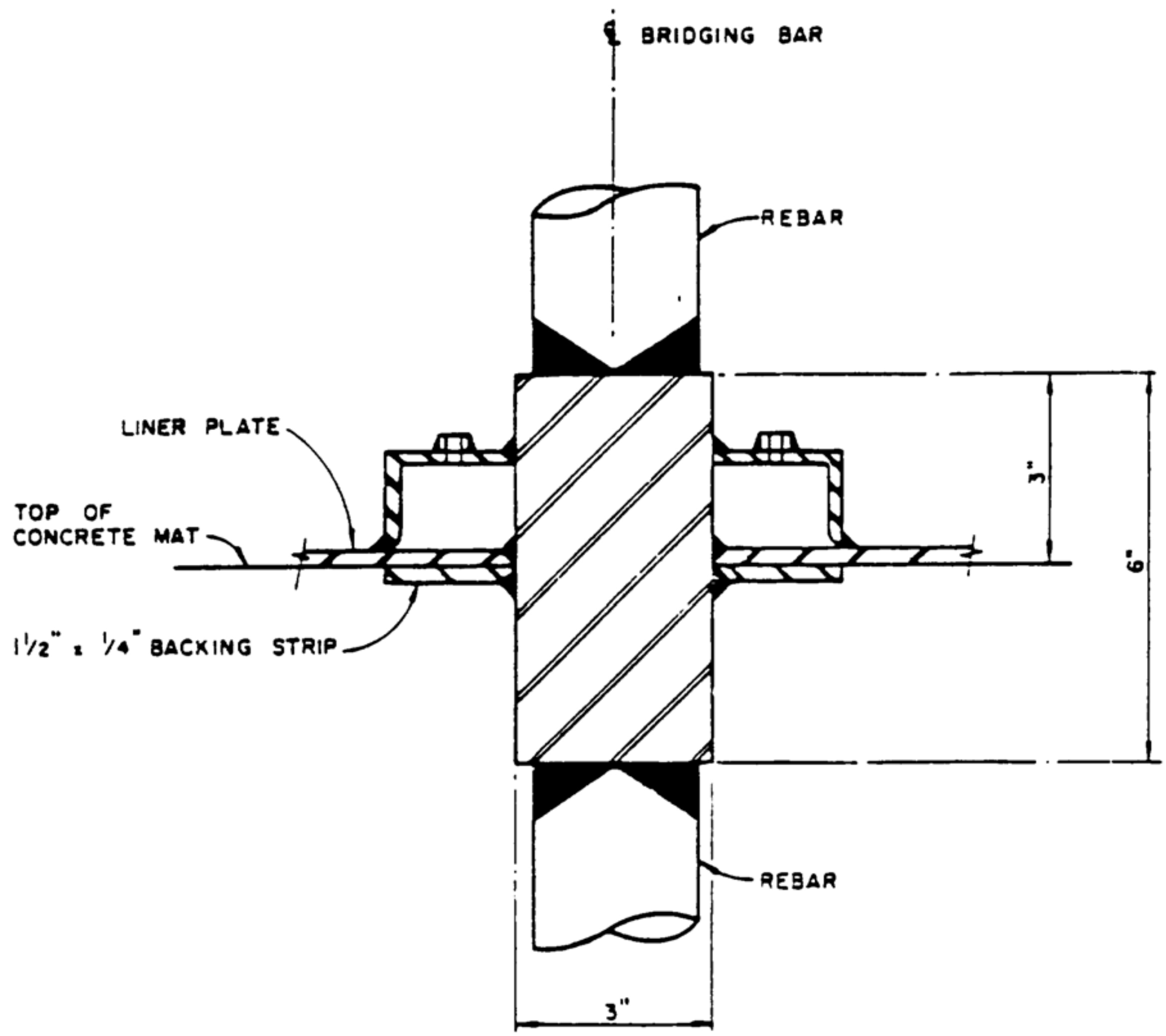
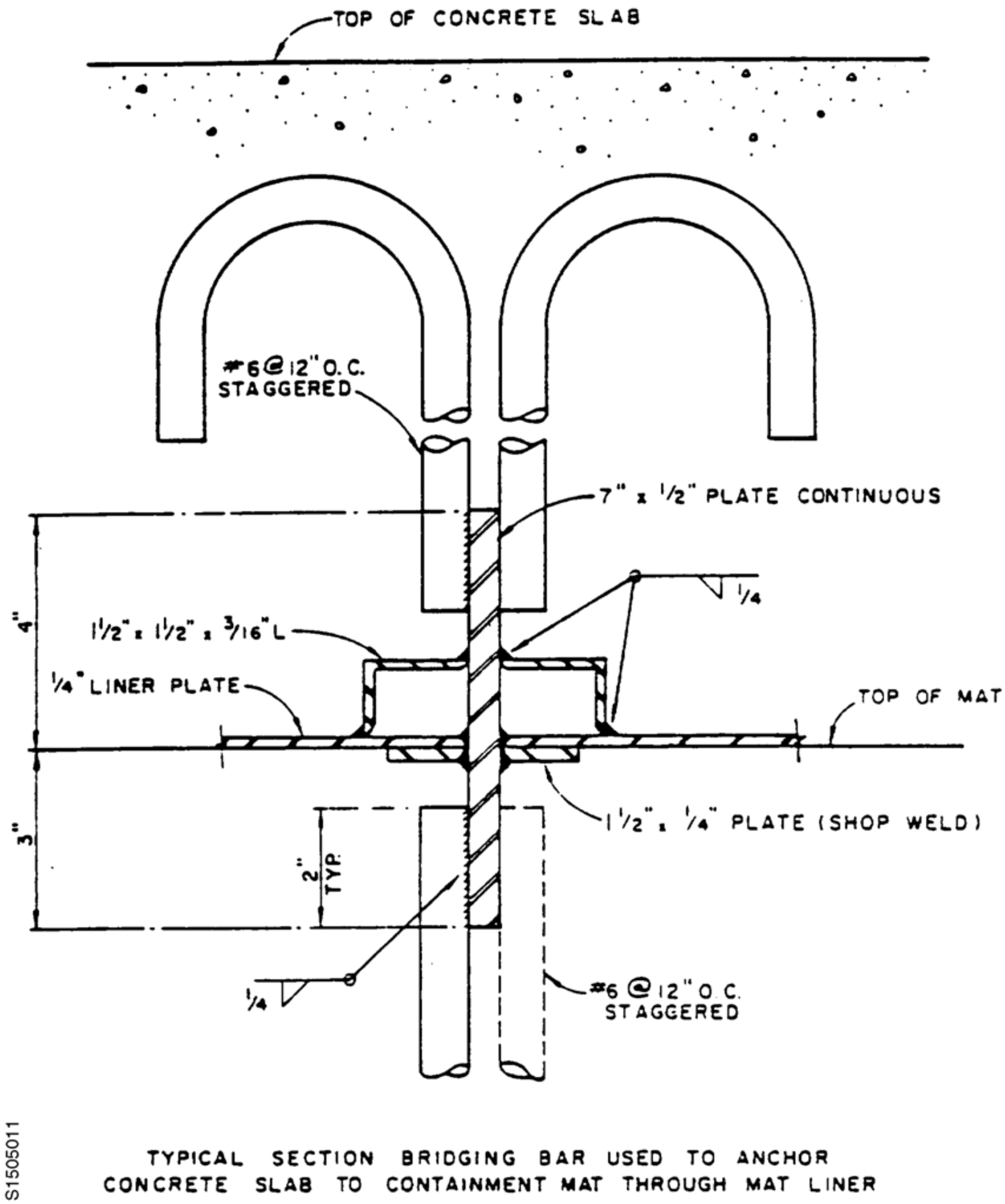


Figure 15.5-8 (SHEET 1 OF 2)
SECTION-TYPICAL BRIDGING BAR



TYPICAL SECTION THROUGH BRIDGING BAR USED TO PROVIDE MAIN REINFORCING STEEL CONTINUITY THROUGH MAT LINER

Figure 15.5-8 (SHEET 2 OF 2)
SECTION-TYPICAL BRIDGING BAR



TYPICAL SECTION BRIDGING BAR USED TO ANCHOR CONCRETE SLAB TO CONTAINMENT MAT THROUGH MAT LINER

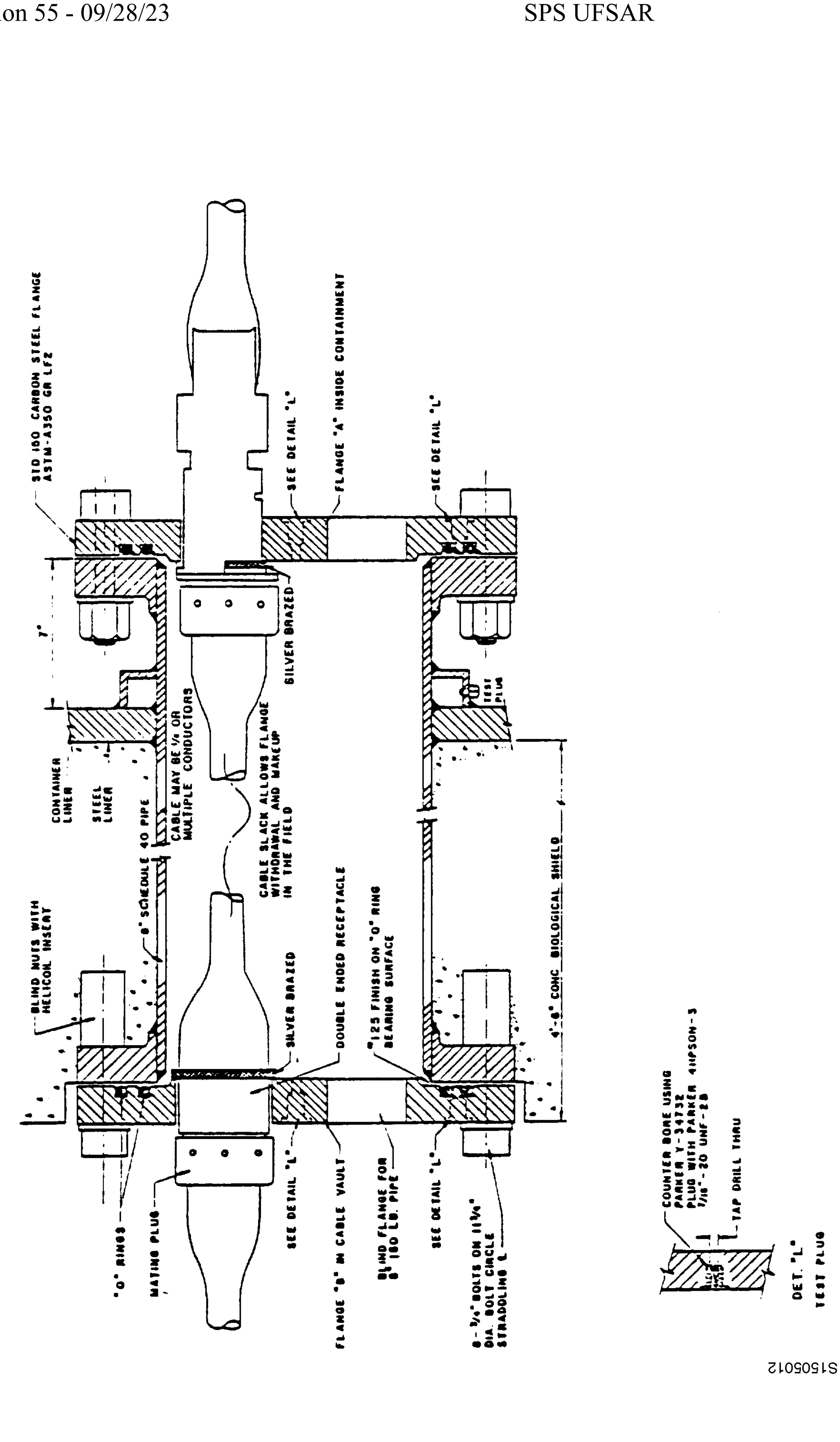


Figure 15.5-9
TYPICAL ELECTRICAL PENETRATION SLEEVE WITH FLANGES

Figure 15.5-10 (SHEET 1 OF 2)
TYPICAL PIPING PENETRATIONS

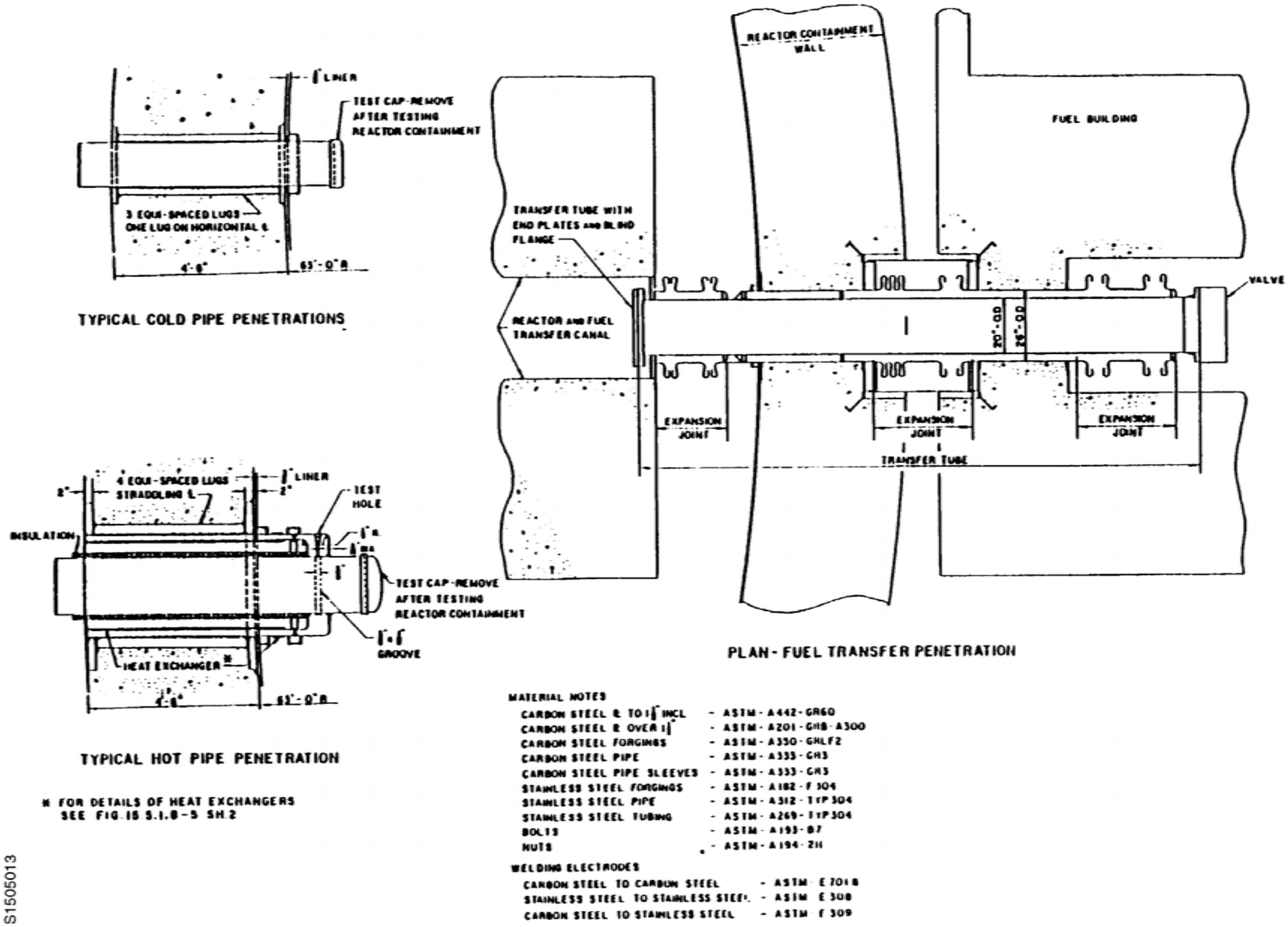
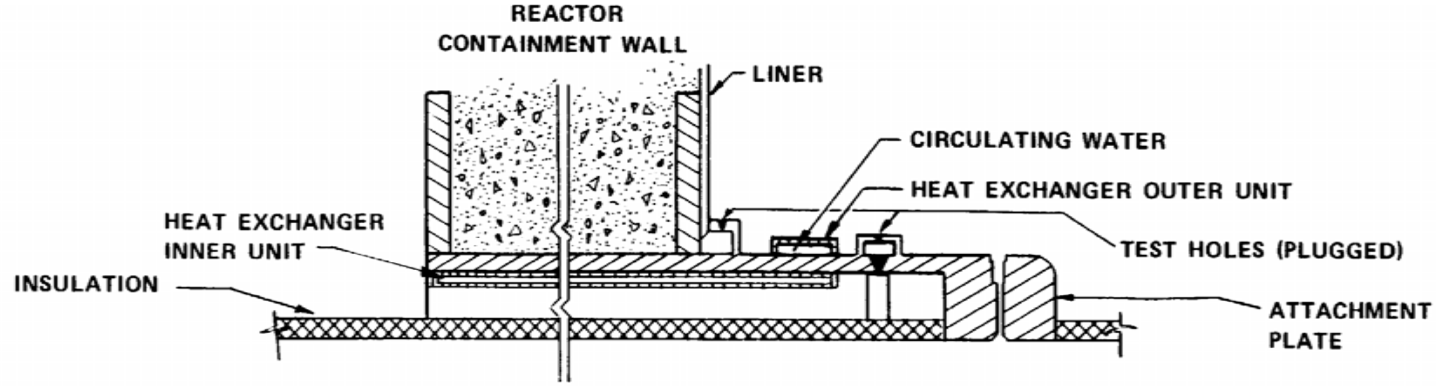
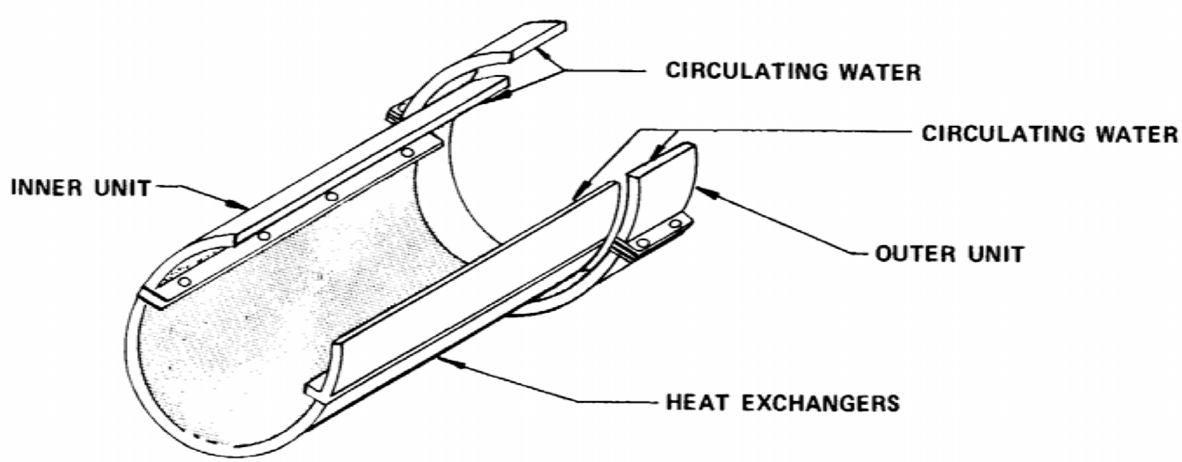


Figure 15.5-10 (SHEET 2 OF 2)
TYPICAL PIPING PENETRATIONS



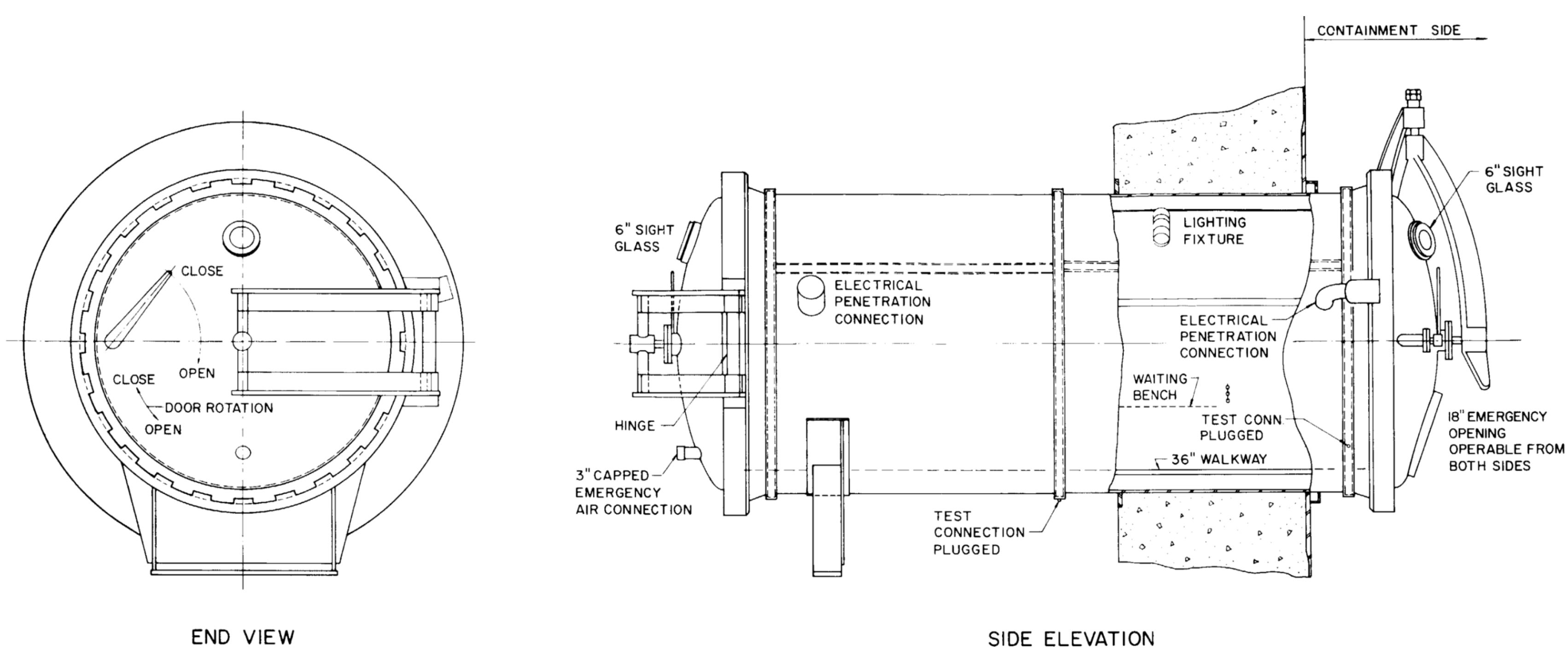
HOT PIPE PENETRATION



TYPICAL PIPING PENETRATIONS

S1505014

Figure 15.5-11
PERSONNEL HATCH ASSEMBLY



1. THE HATCH AND LOCKING MECHANISM ARE DESIGNED TO PROVIDE A CONTINUOUS SEAL AGAINST ANY PRESSURE WHICH MIGHT BE DEVELOPED DUE TO THE DESIGN BASIS ACCIDENT.
2. OPERATING PROCEDURE TO ENTER THE CONTAINMENT STRUCTURE FROM OUTSIDE:
   A. TURN OUTSIDE LEVER OF OUTER DOOR TO STOP BY SAFETY PIN. WHEN PRESSURE IS EQUALIZED SAFETY PIN WITHDRAWS. CONTINUE TO TURN TO UNSEAL.
   B. SWING DOOR OPEN, ENTER HATCH AND SWING DOOR SHUT.
   C. TURN INSIDE LEVER OF OUTER DOOR TO SEAL.
   D. TURN INSIDE LEVER OF INNER DOOR TO STOP BY SAFETY PIN. WHEN PRESSURE IS EQUALIZED SAFETY PIN WITHDRAWS. CONTINUE TO TURN TO UNSEAL.
   E. SWING DOOR OPEN, ENTER CONTAINMENT AND SWING DOOR SHUT.
   F. TURN OUTSIDE LEVER OF INNER DOOR TO SEAL.
3. FOR THE CONDITIONS OF LEAVING THE CONTAINMENT TO THE OUTSIDE, THE OPERATIONS ARE REVERSED.

S1505015

Figure 15.5-12
TYPICAL LINER DETAILS

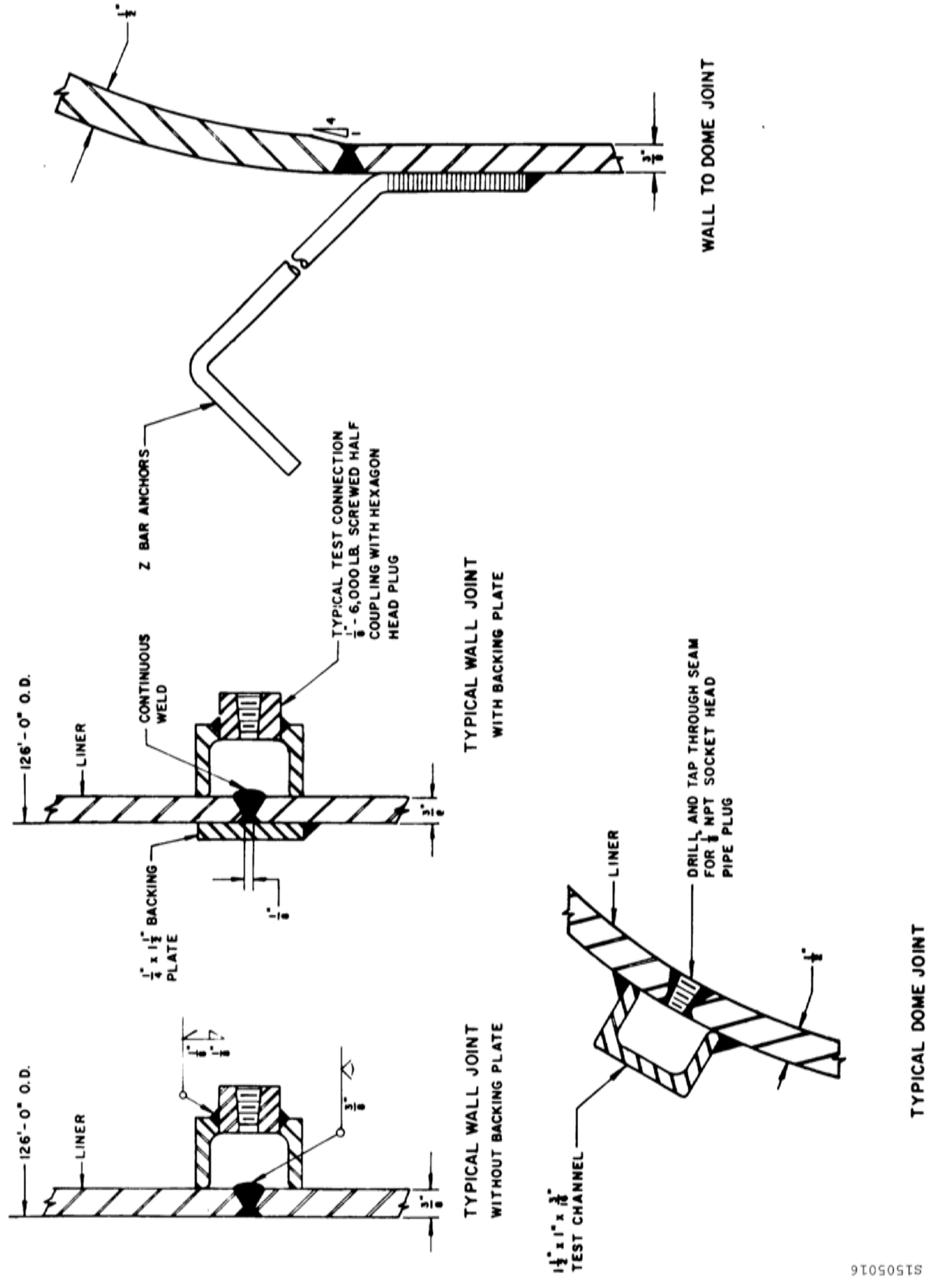
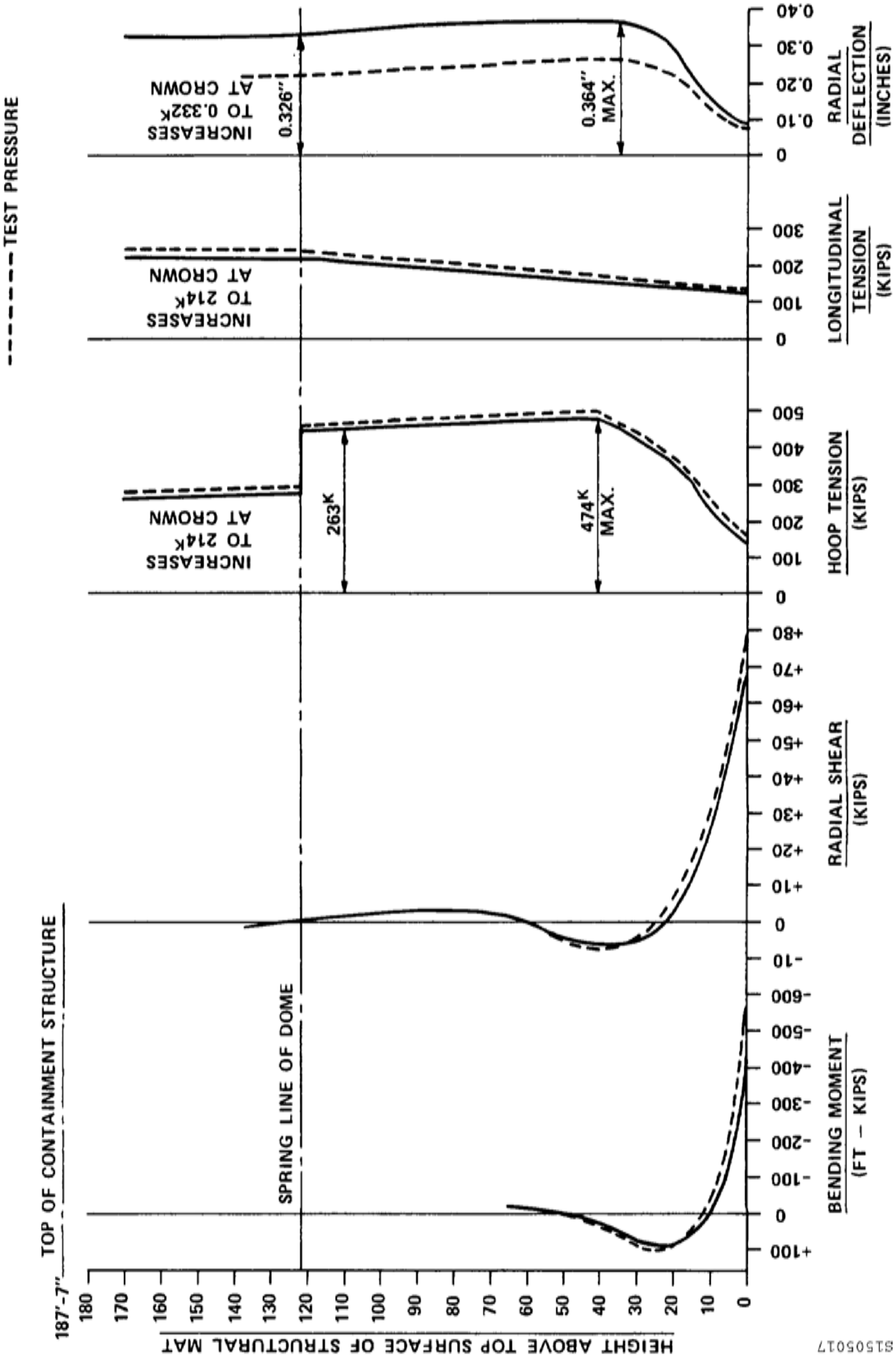


Figure 15.5-13
CONTAINMENT LOADING PLOT

LOADING: (1.0 ± 0.05) D + 1.0P + 1.0 (T + TL)
TEST PRESSURE: 1.15 P



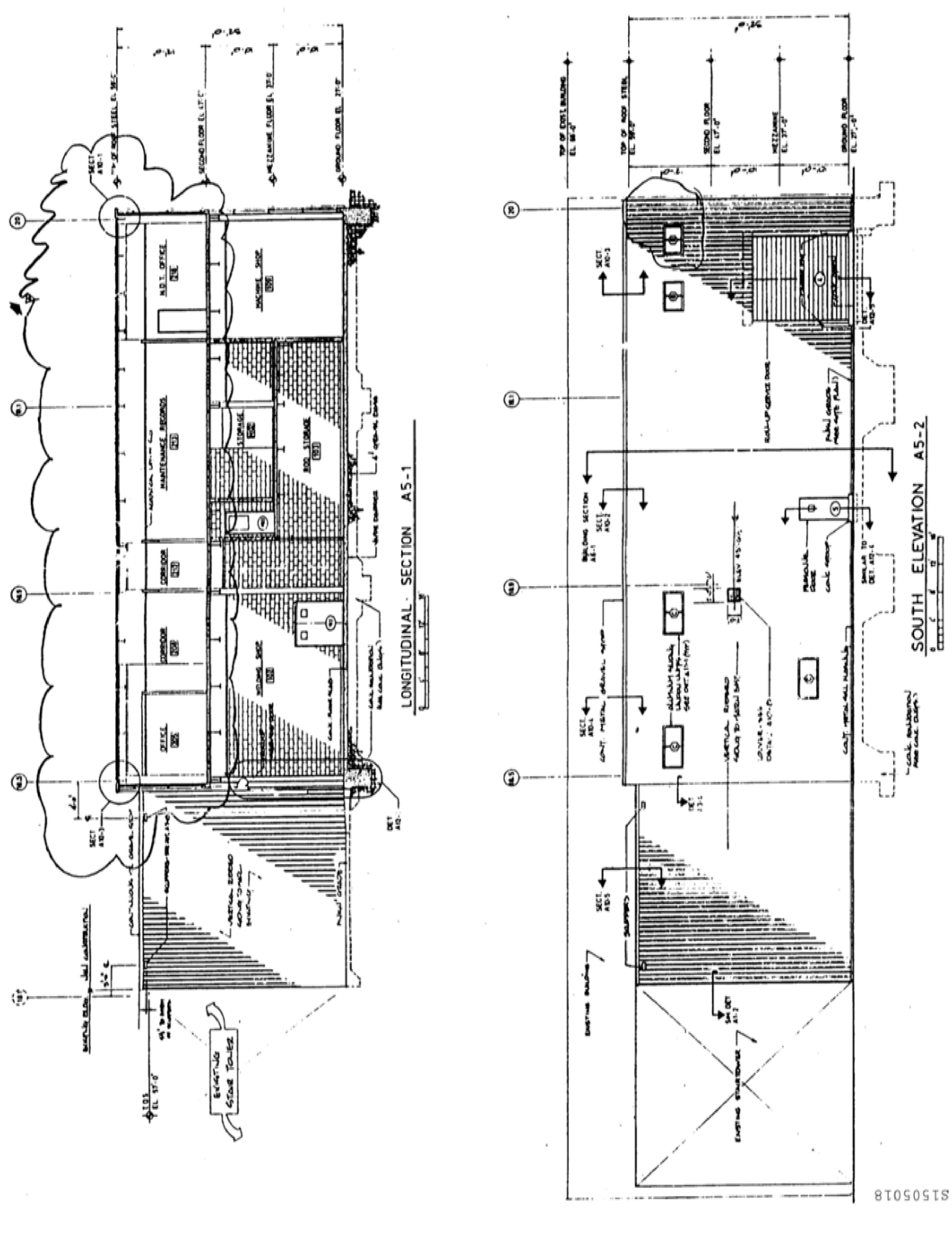


Figure 15.5-14
MACHINE SHOP REPLACEMENT FAC.; SOUTH ELEVATION

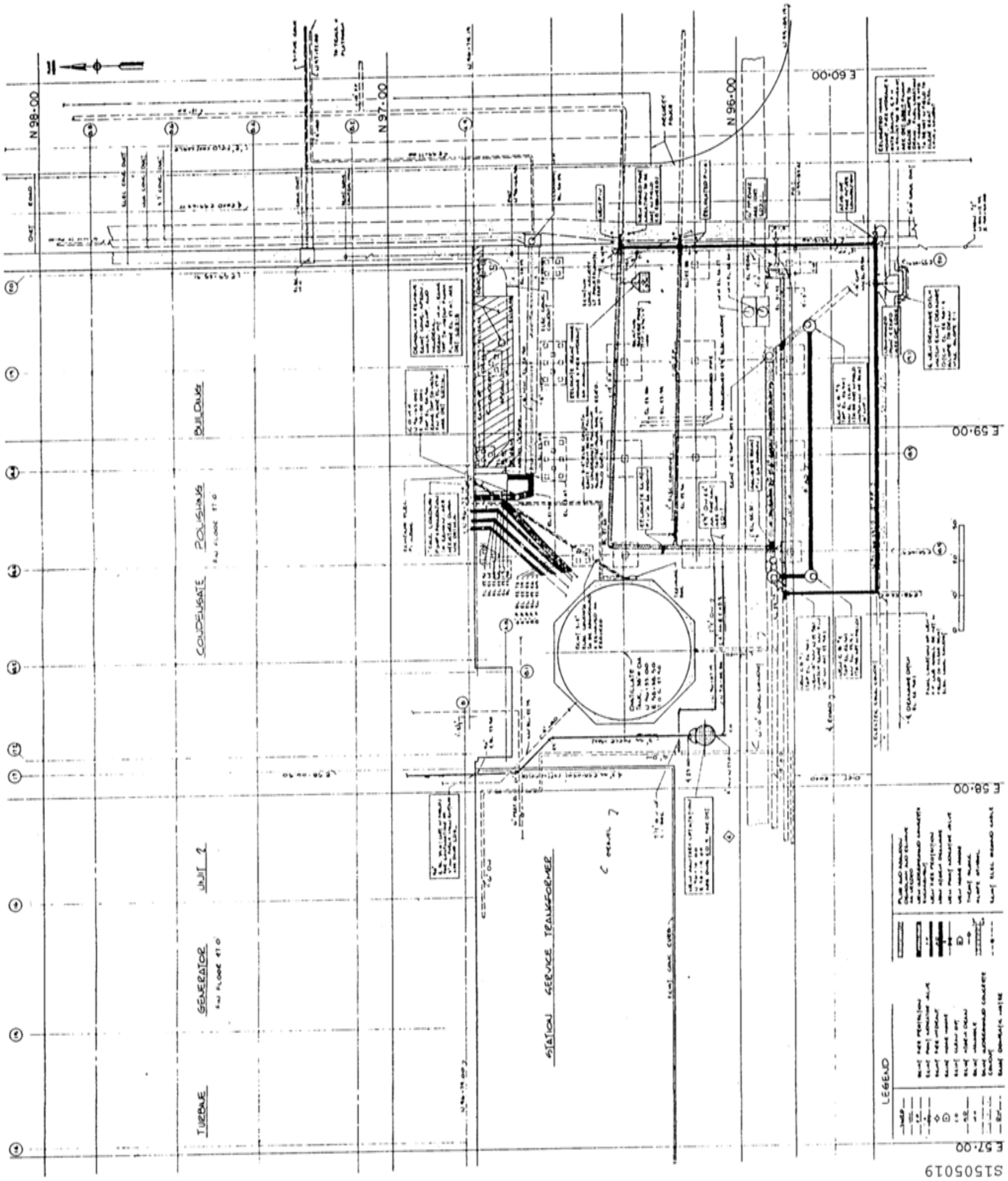


Figure 15.5-15
MACHINE SHOP REPLACEMENT FAC.; SITE PLAN

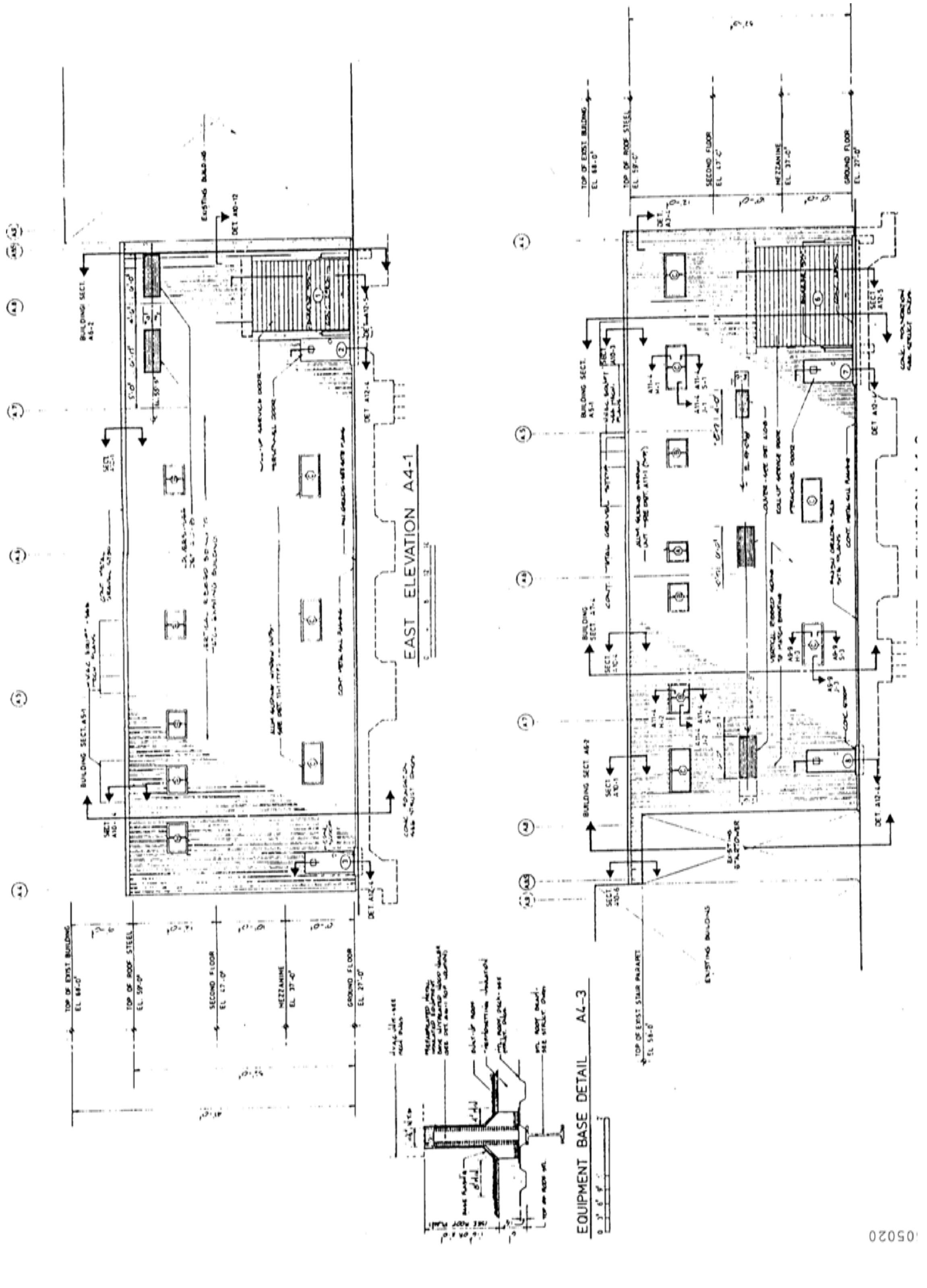


Figure 15.5-16
MACHINE SHOP REPLACEMENT FAC.; EAST/WEST ELEVS.

Intentionally Blank

15.6 OTHER CLASS I STRUCTURES

Class I structures other than the reactor containment structure are listed in Table 15.2-1. The major structures include the auxiliary building, control room area, including switchgear and relay rooms; fuel building; emergency diesel-generator rooms; containment auxiliary structures that contain main steam and feedwater isolation valves, recirculation spray and low-head safety injection pump cubicles, auxiliary steam generator feed pump cubicle, and safeguards ventilation room; and circulating water intake structures, including the high-level canal.

The fuel building, the main steam and feedwater isolation valve section of the containment auxiliary structures, and the refueling water storage tanks are supported on reinforced-concrete mats on concrete-filled steel pipe piles. All other structures are soil-supported on reinforced-concrete mats or spread footings. All Class I structures designed to meet tornado missile criteria, as listed in Table 15.2-1, are enclosed with heavily reinforced, 2-foot-thick concrete walls and roof slabs with all openings shielded against missiles.

Class I structures are designed to resist the operating-basis earthquake without exceeding allowable working stresses, where allowable stresses are one-third above the normal applicable code normal working stress. For concrete structures, a 5% critical damping function is assumed, and the accelerations selected from the acceleration response spectrum curves are considered in conjunction with the natural frequency of each structure. A check has been made to ensure that collapse-type failures will not occur under the design-basis earthquake. For this condition, a 10% damping factor is assumed for concrete structures, and stresses are limited to not more than 120% of the minimum yield point stress. In practice, the controlling feature of the design of these structures was to the satisfaction of the operating-basis earthquake requirements with the limited 5% damping factor.

The high-level intake canal is formed by excavating to Elevation +5 ft. from an average grade of approximately 35 feet. Earth fill dikes constructed on either side of the canal bring the finished height to Elevation +36 ft. throughout the length of the canal. The interior surfaces of the canal are lined with a 4.5-inch-thick reinforced-concrete slab. Under drains and pressure relief valves are provided to prevent uplift of the concrete liner by unbalanced hydrostatic pressure.

15.6.1 Other Structures

All other structures are designed to adequately support all dead, live, and wind loads. Where necessary, subsurface walls and slabs are designed to resist the horizontal component of the soil with applicable surcharge and hydrostatic pressures.

Structural steel design conforms to the 1963 issue of the *Specification for the Design, Fabrication and Erection of Structural Steel for Buildings* of the American Institute of Steel Construction, except as noted herein. Plastic design methodology, in accordance with Part 2 of the 1969 issue of the Specification for the Design, Fabrication and Erection of Structural Steel for Buildings of the American Institute of Steel Construction, has been used to modify the main bents of the Fuel Building steel superstructure. All concrete work is designed in accordance with the *Building Code Requirements for Reinforced Concrete*, serial designation 318-63 of the American Concrete Institute. Access and egress requirements, as well as fire ratings of walls and floor systems, satisfy the requirements of the Basic Building Code of the Building Officials Conference of America, 1966 issue.

Under the design-basis accident loading, the allowable stresses do not exceed 90% of the minimum yield strength of the structural steel. From mill test reports, the yield strength of structural steel is 42,000 psi, with an ultimate strength of 63,000 psi. Using a minimum yield of 36,000 psi for A36 steel, the design-allowable stress is 90% of 36,000 = 32,400 psi.

Design-allowable stress for structural steel is $\frac{32,400}{63,000}$ = 51.5% of the ultimate strength.

Tests on special reinforcing steel with a minimum yield of 50,000 psi have resulted in yield strength of 55,500 psi, with an ultimate strength of 90,000 psi; with a design-allowable stress of 90% of minimum yield, the design-allowable stress is $0.9 \times 50{,}000 = 45{,}000$ psi.

Design-allowable stress on reinforcing is $\frac{45,000}{90,000}$ = 50% of ultimate strength.

Concrete continues to increase in strength beyond the 28-day strength of 3000 psi. The Bureau of Reclamation Concrete Manual indicates that Type II cement concrete can be expected to increase in strength approximately 30% in 1 year from the 28-day strength.

Approximate 28-day strength for 3000-psi concrete from test reports = 3800 psi

Design allowable 85% of 3000 psi = 2500 psi

Ultimate strength in 1 year = $1.3 \times 3800 = 4950$ psi

Design allowable is $\frac{2500}{4950}$ = 51% of ultimate strength in 1 year.

The above figures show that, for structures designed for the design-basis accident loading, structural steel and reinforced concrete are designed at approximately 50% of their ultimate strength. In the design of concrete structural members under design-basis accident conditions, concrete strength is not the controlling factor.

Allowable soil bearing values for foundations are determined from the soil boring logs and the results of triaxial shear tests of the soil. Applicable factors of safety are applied to the test results.

15.6.2 Reactor Coolant System Supports

The reactor coolant system includes the reactor vessel, three steam generators, three reactor coolant pumps, and a pressurizer for each unit. Structures are provided to support these heavy vessels and equipment, and to ensure system integrity during normal operation and design-basis accident conditions.

The primary equipment supports of the reactor coolant system are designed to withstand the design-basis earthquake acting simultaneously with an instantaneously applied pipe break. The original configuration of the Reactor Coolant System (RCS) equipment supports included ten large-bore (12-inch diameter) hydraulic snubbers per loop to carry the loads from postulated reactor coolant system, main steam line and feedwater pipe ruptures.

Subsequently, studies to address Unresolved Safety Issue A-2 (effects of asymmetric pressure loads resulting from PWR primary loop ruptures) concluded that the probability of rupture of the primary coolant loop is extremely small, and that the presence of a pipe crack could be detected by leakage well before the crack grew to critical size which would cause rupture. These “leak-before-break” analyses, documented in References 1 and 2, were submitted to the NRC on behalf of the Westinghouse Owners Group, which included Surry Power Station.

NRC Generic Letter 84-04, *Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Loops*, provided the NRC staff safety evaluation concluding that, provided certain specific conditions are met, an acceptable technical basis exists so that asymmetric pressure loads resulting from pipe breaks in the reactor coolant system primary loop need not be considered as a design basis for the reviewed plants. The plant-specific conditions were a limitation on the maximum bending moments in the primary loop piping for normal operating and seismic loadings, and the existence of an adequate reactor coolant leakage detection system. The affected plants were encouraged to submit requests for partial exemptions from General Design Criterion 4 (GDC-4), to permit elimination of pipe rupture restraints required to protect against these previously postulated breaks.

Because a number of the large-bore snubbers served primarily as pipe rupture restraints, Surry proceeded with an exemption request to allow elimination of 6 of the 10 snubbers per loop, based on application of leak-before-break in accordance with Generic Letter 84-04. (The other 4 large-bore snubbers on the upper steam generator support were required for lateral loads due to a postulated longitudinal split of the main steam line.) The reactor coolant loop system was re-evaluated with all snubbers on the steam generator lower support and the reactor coolant pump supports eliminated, to assure that the conditions of pressure, deadweight, thermal, seismic, and remaining pipe rupture effects, would not result in unacceptable stress levels or factors of safety. Largely independent analyses were performed by Westinghouse and Stone & Webster in accordance with the original division of design responsibilities. Interface force allowable limits at NSSS boundaries were assured and support design load interfaces were reviewed for acceptance.

The exemption request to allow elimination of 18 snubbers per unit was filed with the NRC on November 5, 1985 (Reference 3). The detailed technical basis (Reference 4) provided separate attachments addressing load evaluation, leakage detection, and net safety balance. The proposed design changes were discussed with the NRC and resulting NRC concerns were addressed (References 5 & 6). The GDC-4 “limited scope” revision (Reference 7) was subsequently published (effective May 12, 1986) permitting the use of leak-before-break technology to justify elimination of the dynamic effects of primary loop breaks from the design basis of PWRs. With the publication of the notice of revision to GDC-4, a license amendment to the plant design basis was requested to implement the snubber reductions under the new rule (Reference 8). By letter dated June 16, 1986, the NRC approved the license amendment (#108) for both units (Reference 9). The snubber eliminations were implemented by Design Changes 85-04-1 and 86-12-2.

Subsequently, the NRC issued Generic Letter 87-11, *Relaxation of Arbitrary Intermediate Breaks* which provided the revised Mechanical Engineering Branch position eliminating the need to postulate Arbitrary Intermediate Breaks. As stated in the generic letter, the elimination of Arbitrary Intermediate Breaks allows elimination of the associated pipe whip restraints and jet impingement shields. Because the stresses in the main steam lines inside containment are well below the stress criteria for required mandatory intermediate breaks, the only breaks which need to be postulated are terminal end breaks which do not apply lateral loads to the steam generator. Therefore, the governing lateral loads on the steam generator become those imposed by the main feedwater break, which are low enough that only a single snubber in each pair will be required to carry the load. Analyses were performed by Westinghouse and Stone & Webster similar to those performed for the earlier large-bore snubber reduction to ensure piping stress levels and component factors of safety were acceptable. In addition, it was necessary to verify that the basis for the previous license amendment based upon leak-before-break of the primary loop remained valid. Comparison of results with the lower large-bore snubber of each pair removed as a result of eliminating the main steam line split vs. the results in the previous leak-before-break submittals, confirmed that there were no significant reduction in margins of safety. Therefore, elimination of the lower large-bore snubber of each pair does not compromise the bases for the previous leak-before-break analysis, namely:

1. The loading on the primary loop piping is still enveloped by the generic analyses submitted on behalf of the A-2 Owners Group, and accepted by the NRC staff in Generic Letter 84-04, and specifically for Surry by NRC letter dated June 16, 1986; and
2. The reactor coolant system equipment, piping, and supports continue to have acceptable margins of safety under licensed loading conditions other than the now-eliminated ruptures of the primary loop piping and Arbitrary Intermediate Break of the main steam lines.
3. The application of Leak-Before-Break (LBB) methodology to justify the elimination of postulated line breaks of reactor coolant loop piping from the structural design basis was subsequently extended to the Surry Units 1 and 2 Reactor Coolant System (RCS) branch piping including: the Pressurizer Surge, Residual Heat Removal (RHR), Accumulator, Loop Bypass, and Safety Injection (SI) piping up to each line's first pressure isolation valve. The technical evaluation justifying the extension of LBB to the RCS branch piping was performed by Westinghouse in WCAP-18491-P/NP, Rev. 0 (Reference 12), and submitted to the NRC for review and approval (Reference 13). The NRC approved the extension of LBB to the RCS branch piping noted above in their Safety Evaluation Report (SER) included in Surry Units 1 and 2 License Amendments 304 and 304 for the 80 year period of extended

operations (Reference 14). The technical basis provided in WCAP-18491-P, Rev. 0, and approved by the NRC SER, is based on the following conclusions:

a. Stress corrosion cracking (SCC) is precluded by use of fracture resistant materials in the piping system and controls on reactor coolant chemistry, temperature, pressure, and flow during normal operation. Note: Alloy 82/182 welds do not exist at the Surry Units 1 and 2 Surge, RHR, Accumulator, Loop Bypass and SI lines.

b. Water hammer should not occur in the Surge, RHR, Accumulator, Loop Bypass and SI line piping because of system design, testing, and operational considerations.

c. The effects of low and high cycle fatigue on the integrity of the Surge, RHR, Accumulator, Loop Bypass and SI line piping are negligible.

d. Ample margin exists between the leak rate of small stable flaws and the capability of the Surry Units 1 and 2 Reactor Coolant System pressure boundary leakage detection systems.

e. Ample margin exists between the small stable flaw sizes of item (d) and larger stable flaws.

f. Ample margin exists in the material properties used to demonstrate stability of the critical flaws.

For the critical locations, postulated flaws will remain stable and because of the ample margins described in d, e, and f above.

Based on loading, pipe geometry, welding process, and material properties considerations, enveloping critical (governing) locations were determined at which LBB crack stability evaluations were made. In the Extended Leak Before Break (eLBB) analysis (Reference 12), through-wall flaw sizes were postulated which would cause a leak at a rate of ten (10) times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Additionally, the impact of fatigue crack growth was assessed and shown not to be an issue for the Surge, RHR, Accumulator, Loop Bypass and SI line piping; therefore, the LBB conditions and margins are satisfied for this piping. Based on the WCAP (Reference 12) evaluation discussed above and the associated NRC SER (Reference 14), it was demonstrated that the dynamic effects of the pipe rupture resulting from postulated breaks in the Surge, RHR, Accumulator, Loop Bypass and SI line piping need not be considered in the structural design basis of Surry Units 1 and 2 for the 80 year period of extended operations.

15.6.2.1 **Design Basis**

All supports in the reactor coolant system are designed to withstand the design-basis earthquake acting simultaneously with an instantaneously applied pipe break. As discussed above, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop. However, single ruptures are postulated to occur in either the pressurizer surge or other reactor coolant branch lines, the main steam piping, or the main feedwater piping. In general, two types of piping failures are considered: a double-ended rupture, or a longitudinal rupture on either the horizontal or vertical axis of the pipe. The longitudinal rupture area was taken to be equal to the area of the double-ended rupture for these piping failures. Stresses in the main steam piping inside containment have been reviewed and, in accordance with NRC Generic Letter 87-11, are sufficiently low that no intermediate break need be postulated. Only terminal end breaks need be postulated; in accordance with Generic Letter 87-11, it is not necessary to postulate longitudinal rupture at terminal end breaks. Therefore, only vertical loads are considered to be applied to the steam generators due to a postulated main steam line break. For all postulated breaks, the pipe rupture loads are combined with design-basis seismic loads by the square-root-sum-of-squares (SRSS) method.

The peak value of the pipe thrust for any of the main steam piping breaks considered is approximately 620,000 lb; and the peak value for the pipe thrust for the pressurizer surge pipe break is approximately 195,000 lb. These thrust values are equal to $P \times A$, the system pressure times rupture area.

For the pressurizer surge line break and other branch line breaks, the load versus time transients of these breaks are provided by a computer program that analyzes the shock wave initiated at the break as it passes through the complete piping loop. Results from this program are used as forcing functions in a structural dynamic program that results in the dynamic loadings of the supports. For the main steam line and feedwater line breaks, the dynamic forces were applied only at the steam generator nozzles, because the primary reactor coolant loop piping remains intact. The peak values of the pipe thrust for the postulated piping breaks were computed as $C_r \times P \times A$, the thrust coefficient times the system pressure times the rupture area. These values were used as the basis for developing conservative time-history forcing functions of the postulated breaks. In addition to the thrust loading, jet impingement effects were included as appropriate. For the main steam line vertical break, credit was taken in calculating the thrust loading for the flow area reduction of the flow restrictors installed at the nozzle during the steam generator replacement project; the jet impingement loading is not reduced by the flow reducers. The time-history forcing functions are input into the structural dynamic analysis program that calculates maximum loadings on the supports. For each analyzed break, the maximum support loads are determined and then combined by SRSS summation with design-basis earthquake loads, and then added directly to the loadings due to normal operation. Combined stresses are maintained within 90% of the minimum yield point of the structural material used. For the RPV sliding foot supports, LOCA loads are developed using the AREVA methodology described in Chapter 14 Section 14.5.3.4.1.

All welding is in accordance with Section IX of the ASME Code, and all welds are examined by either radiographic, sonic, dye penetrant, or magnetic particle techniques, depending on the material and the state of stress at the weld.

The seismic restraints (snubbers) that are installed on the piping systems throughout the plant and that are required to protect the reactor coolant system or any other safety-related system are subject to operability and surveillance requirements contained within the Technical Specifications. Vepco has established a program and procedures for inspecting, testing, and maintaining snubbers in compliance with the Technical Specification requirements. A listing of all safety-related hydraulic and mechanical snubbers is maintained by Surry Power Station.

15.6.2.2 **Description**

15.6.2.2.1 Reactor Vessel Support

The reactor vessel is supported by six sliding foot assemblies mounted on the neutron shield tank. The support feet are designed to restrain lateral and rotational movement of the reactor vessel while allowing thermal expansion. The neutron shield tank is a double-walled cylindrical structure that transfers the loadings to the heavy reinforced-concrete mat of the containment structure. The tank also serves to minimize gamma and neutron heating of the primary concrete shield, and to attenuate neutron radiation outside of the primary shield to acceptable limits (Section 11.3.2.1). The neutron shield tank assembly and material listing are shown on Figure 15.6-1.

Sliding support blocks mounted on top of the shield tank support the reactor vessel. These sliding support blocks permit radial thermal expansion of the reactor vessel, while preventing translation, rotation, or uplifting[1]. The support blocks are also designed to adjust to the correct height for plumbing the reactor vessel and for distributing the load properly among the six supports.

The loading conditions used in the analysis of the neutron shield tank were the simultaneous accelerations of a design-basis earthquake, the thrust forces exerted by the reactor vessel due to a double-ended reactor coolant pipe rupture,[2] and the dead weight of the system and the tank itself, with stresses not to exceed allowable working stresses, and with no loss of integrity or function.

The neutron shield tank has been designed using the theory of a shell structure, dynamically loaded in both horizontal and axial planes, which results in meridional and circumferential stresses at all points along its length. The stresses in the tank were determined by using the methods and theories of Timoshenko for plates and shells, elasticity, and elastic stability. All membrane stress levels were held to the limits stated in Section VIII of the ASME Code; all membrane-plus-bending stresses were held to 90% of yield point. Section VIII of the ASME Boiler and Pressure Vessel Code was used as a guide in the fabrication and welding of the tank. A code stamp was not required, since this is not a code pressure vessel but a supporting structure for the reactor pressure vessel.

---

1. It is no longer necessary for the RPV sliding foot supports to restrain uplift based on new LOCA loads developed as discussed in Section 14.5.3.4.1. The combined seismic and LOCA loads when added to dead weight are not sufficient to create uplift in the supports.
2. As discussed previously in this section, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop piping. However, pipe ruptures of reactor coolant branch lines must still be considered.

All material employed in the fabrication of the tank was new and conformed to ASTM Standards. The tank shell was constructed from ASTM A516, Grade 60, and the six sliding support blocks were made of maraged steel. The material has an NDT of -20° to -40°F. Drop weight tests were performed to determine the nil ductility transition temperature of the deposited weld metal in welding the ASTM A516, Grade 60 material with an NDT of -40°F. The maraged steel was ultrasonically tested for flaws to the quality level of MIL-1-8950. Flaws detected ultrasonically were verified by X-ray. Maraged steel pieces with verified flaws larger than 1/32 in. were rejected. The maraged steel had a maximum hardness of 35 Rockwell C and a minimum grain size of 6, in accordance with ASTM E-112 and MIL-Std-430, *Macrograph Standards for Steel Bars, Billets, and Blooms.* The nonmetallic inclusion content for each billet was determined in accordance with ASTM E45. Fracture toughness tests were performed on maraged steel in accordance with ASTM Specification, *Proposed Recommended Practice for Plane-Strain Fracture Toughness Testing of High-Strength Metallic Materials Using a Fatigue-Cracked Bend Specimen,* Part 31, ASTM Standards.

All welds, where possible, were 100% radiographed in accordance with Paragraph UW-51 of the ASME Boiler and Pressure Vessel Code Section VIII, Division 1. Other welds that could not be radiographed were dye-penetrant checked at root pass, intermediate depths at half-inch increments, and the final pass, or magnetic-particle tested, in accordance with Appendices VI and VIII, Section VIII, ASME Boiler and Pressure Vessel Code. The surfaces of welds were ground to a surface condition suitable for the inspection procedure employed. Defects in welds were removed by chipping, grinding, or arc gouging until sound metal was reached. The resulting cavity was rewelded, employing an approved procedure.

After shop fabrication, the completed tank was subjected to a hydrostatic test of 15 psi, measured at the top of the tank. No water loss was observed for a 24-hour period. The tank was then leak tested with air at 5 psi gauge, applying soapsuds to all welds accessible from outside the tank. Leaks were repaired and the tank retested until no leakage was detected. All tests were recorded and certified. After installation of the neutron shield tank at the job site, the tank was hydrostatically retested.

15.6.2.2.2 Steam Generator Support

The steam generator support consists of two (upper and lower) cast rings and associated suspension rods, lateral restraints and snubbers. The lower ring, which carries the steam generator weight, is suspended by means of three pipe columns. Hydraulic snubber cylinders and rigid lateral guides connect the upper casting to the steam generator cubicle structure to allow guided thermal expansion of the steam generator outward from the reactor during normal operation, while resisting movement during seismic and pipe break conditions. Due to the design of this support system (i.e., pin-ended connections at all member joints) lamellar tearing of the supports could not occur. The steam generator support assembly and material listing is shown on Figure 15.6-2. The supports do not have any heavy section intersecting member weldments.

The major materials used in the construction of the steam generator supports are listed in Table 15.6-1. The difference between the operating temperature and the NDT of the material ensures toughness and ductility of the steam generator supports under all operating conditions. Welding associated with the supports was conducted in accordance with Section IX of the ASME code.

In addition to numerous inspections and tests carried out by the material suppliers and fabricators, all of the components for these supports were subject to inspection during fabrication and installation by Stone & Webster Engineering Corporation. All welds were subjected to examination by either the magnetic particle, liquid penetrant, or radiographic methods. The Vascomax 350 CVM and 300 CVM materials, and the A-352 grade LC3 casting materials were subjected to examination by the magnetic particle and ultrasonic methods. A visual inspection of a portion of these supports is required by the Technical Specifications.

The upper restraining ring is composed of two girth straps coupled together by studs to form a continuous ring. The studs are 1.25-inch 12UNF-2A Vascomax 18% Ni, maraging grade 350, with nickel cadmium coating. The nuts are 1.25-inch 12UNF-3B Vascomax 18% Ni, maraging grade 250, with Helicoil inserts. The studs and nuts are designed to minimize stress concentration during manufacture, and the studs are coated for environmental protection. The studs are pretensioned across a joint flange spacer block, which serves to reduce bending stresses in the studs.

A total of nine machined shoe openings are welded to each vessel girth strap. These shoe openings accommodate nine keys which themselves are fastened by dowels to the large upper restraint casting which is shown on Figure 15.6-2. These key and shoe openings function to allow vertical thermal expansion of the steam generator within the upper restraint casting, but will restrict lateral movement resulting from forces generated during a seismic event and/or a major pipe break applying lateral loads to the steam generator.

In a seismic event and/or a major pipe break applying lateral loads to the steam generator, the shoe openings in the vessel girth straps act against the keys, which results in a tangential load on the girth straps. The subject studs are designed to accommodate the maximum tangential load resulting from this accident condition. Existing space restrictions and restraint design required a limitation on stud size and quantity which necessitates the use of an ultra-high strength bolting material. The studs have a minimum yield strength of 326,000 psi. The nuts have a minimum yield strength of 150,000 psi.

The upper restraint casting is anchored to the containment structure (approximate 47-foot level) through rigid lateral guides oriented in the direction perpendicular to the outward thermal movement of the steam generator, and by two horizontal large-bore hydraulic snubbers, which permit the thermal movement of the steam generators outward from the reactor. The large-bore snubbers are 12-inch-diameter Pathon snubbers which have been refurbished and upgraded for increased reliability by Paul-Monroe/Remco Hydraulics under Design Change 85-05. The modifications included chroming the cylinder inner diameters; replacement of all non metallic seals with extended-service-life Tefzel seals or metallic seals; installation of poppet-type self-cleaning control valves for improved performance; conversion to the standard snubber hydraulic fluid (General Electric SF-1154); and incorporation of test-in-place features. In addition, the original common reservoir serving a number of snubbers has been replaced by individual pressurized reservoirs installed in more readily accessible locations in lower radiation areas outside the biological shield walls. The reservoirs are plated and the tubing and fittings are stainless steel for corrosion resistance.

The lower restraining ring is also connected to the steam generator cubicle concrete structure by couplings consisting of two end plates installed perpendicular to one another. The end plates have machined dovetails and are joined by a connector plate with mating dovetails. Although the couplings are resistant to corrosion cracking, additional protection is provided by enclosing each coupling in a rubber boot filled with silicone lubricant. The boot and lubricant are compatible with the coupling and are also radiation resistant.

15.6.2.2.3 Reactor Coolant Pump Support

The reactor coolant pumps are supported by a four-legged suspended structure. (Four small-bore snubbers originally installed in the upper frame structure of the pump support were eliminated under Design Changes 85-04-1 and 86-12-2. The dynamic characteristics of the reactor coolant pump were not significantly affected by removal of these snubbers as discussed in Reference 6.) The reactor coolant pump support assembly and material listing are shown on Figure 15.6-3. The supports do not have any heavy section intersecting member weldments.

The major materials used in the construction of the reactor coolant pump supports are listed in Table 15.6-2. Welding associated with the supports was conducted in accordance with Section IX of the ASME Code.

In addition to numerous inspections and tests carried out by the material suppliers and fabricators, all of the components for these supports were subject to inspection during fabrication and installation by Stone & Webster Engineering Corporation. All welds were subjected to examination by either the magnetic particle, liquid penetrant, or radiographic methods. The Vascomax 350 CVM and 300 CVM materials, and the A-352 grade LC3 casting materials were subjected to examination by the magnetic particle and ultrasonic methods. A visual inspection of a portion of these supports is required by the Technical Specifications; however, there is no formal inspection program for all components of the supports during the life of the facility. Major inspections potentially involving disassembly can be conducted on an as-needed basis.

During normal operation the loads and stresses for piping, component connections, and other remaining component supports are not sufficient to cause the failure of the reactor coolant system piping, should there be a complete failure of the reactor coolant pump supports. The maximum stresses that can be expected in the reactor coolant piping as a result of failure of the reactor coolant pump supports during normal operation are summarized in Table 15.6-3. These loads are within the allowable nozzle loads for both the steam generator nozzle and the reactor pressure vessel nozzles. The allowable stresses for the reactor coolant pipe material (A376 Tp 316) are also summarized below. While several of these values are above yield at 650°F, they are all less than 50% of the material's ultimate strength at that temperature. The reactor coolant pipe material has an S_n (code-allowable for normal operation) of 16 ksi at 650°F, and the faulted allowable stress would be 1.85 S_n or 28.8 ksi. All of the loads summarized below are within this faulted allowable, with the exception of the pressurizer inlet. However, thermal stresses have been conservatively included, and their deletion brings the stress levels well within the allowables.

During any postulated accident condition, i.e. seismic and/or pipe breaks, a concurrent complete failure of the reactor coolant pump support would result in unacceptable consequences throughout the reactor coolant loop piping, in terms of loads and stresses. If these supports were to fail during operation, it would be detected, as there is vibration monitoring instrumentation on both the shaft and the frame of the reactor coolant pumps. The amount of vibration is indicated in the control room, and any excessive vibration would cause an annunciator alarm to sound in the control room. To trigger the annunciator alarms, vibration greater than 3 mils on the frame and greater than 15 mils on the pump shaft must occur.

15.6.2.2.4 Pressurizer Support

The pressurizer vessel is mounted in a rigid support ring girder suspended by three hanger columns from above. Antisway brackets are welded to the shell of the pressurizer to accommodate shear blocks on the ring; the ring girder is laterally supported by a reinforcement plate attached to embedments in the concrete structure. In addition, lateral support for dynamic loads is provided near the vessel's center of gravity by four gapped restraints[1] at lugs on the pressurizer which transmit the loads into baseplates on the concrete floor. The lateral gapped restraints and hanger shear blocks and reinforcement plate are able to take all incident loads while allowing the pressurizer vessel to expand radially and vertically. The pressurizer support assembly and material listing are shown on Figure 15.6-4.

15.6.2.2.5 Evaluation

The dynamic analysis program accounts for dynamic amplification of the support forces. These forces are then combined with the design-basis seismic loadings by SRSS summation to ensure that the supports are conservatively designed to withstand the condition of a pipe break occurring as a result of an earthquake. Rigid quality assurance criteria during fabrication ensure conformance with the conservative design.

15.6.3 Containment Internal Structure

The reactor containment internal structure is a reinforced concrete structure that furnishes:

1. The four lateral gapped restraints were installed by Design Changes 85-04-1 and 85-05-2 to replace the four snubbers in the original support configuration.

1. Supports and restraints for all internal equipment and piping including the polar crane and jib crane.
2. Missile shielding for the containment steel liner and main steam lines against internally generated missiles.
3. Biological shielding for station operators inside the containment structure under all phases of reactor operation.

The structure is designed to withstand the design-basis earthquake together with the simultaneous loss-of-coolant accident (LOCA)[1], without loss of function. Clearance is maintained between all internal structures and the steel liner of the reactor containment shell to permit differential earthquake motion. The steam generator cubicles and the pressurizer cubicle are designed to withstand an internal differential pressure load of 35 psi resulting from the postulated double-ended primary coolant pipe break. The primary shield is designed to withstand an internal pressure of 100 psig resulting from a hypothetical reactor coolant pipe break within the primary shield.

The differential pressure rise within the cubicles is controlled by open and shielded vent spaces in each cubicle, which permit rapid pressure equalization within the containment structure.

This transient pressure condition has been calculated by Stone & Webster's CUPAT Program, using input from the LOCTIC Program.

Temperature differentials between cubicles are considered coincident with the pressure differentials. The short duration of the transient accident relative to the low thermal conductivity of the concrete is such that no significant temperature gradient occurs across the walls. Also, the transient accident is not considered to add to the differential cubicle wall loadings.

Structural concrete design conforms to the requirements of ACI 318, Part IV-B, Ultimate Strength design. Maximum stresses are limited to 90% of the minimum yield point in bending, or 85% of the minimum yield point in diagonal tension, bond, and anchorage.

Special large-size reinforcing steel bars No. 14 and No. 18 are controlled chemistry steel of 50,000 psi yield point, otherwise conforming to the requirements of ASTM A408. All other reinforcing steel is steel of 40,000 psi yield point conforming to ASTM A-15 and ASTM A305.

A stainless-steel-lined fuel transfer canal and reactor refueling cavity is incorporated in the concrete structure above the reactor vessel. A 0.25-inch-thick stainless-steel plate is used to prevent leakage of water from these areas into the containment structure.

1. As discussed in Section 15.6.2, "leak-before-break" analyses have demonstrated that the probability of a rupture of the primary reactor coolant loop piping is extremely low, and it is no longer necessary to consider the dynamic effects of such a break. However, the requirements for design of containment and compartments under pressures associated with a postulated primary reactor coolant loop LOCA remain unchanged.

Portions of the biological shield walls in the steam generator cubicles are composed of removable precast, reinforced-concrete sections. The wall sections are designed for nondestructive removal to assist future servicing of the steam generators.

Structural steel framing is used as bracing along the top, corners, and ends of the removable shield wall sections. The bracing components conform to ASTM A-36 specifications for structural steel. The precast concrete wall sections have an ultimate compressive strength of 3000 psi at 28 days, with steel reinforcement conforming to ASTM specifications for A615, grade 40.

15.6 REFERENCES

1. Westinghouse Topical Report WCAP 9558, Revision 2, *Mechanistic Fracture Evaluation of Reactor Coolant Pipe Containing a Postulated Circumferential Throughwall Crack,* May 1981.
2. Westinghouse Topical Report WCAP 9787, *Tensile and Toughness Properties of Primary Piping Weld Metal for Use in Mechanistic Fracture Evaluation,* May 1981.
3. Letter from Vepco to NRC, Subject: Request for Partial Exemption from General Design Criterion 4, dated November 5, 1985 (Serial No. 85-136).
4. Letter from Vepco to NRC, Subject: Request for Partial Exemption from General Design Criterion 4 - Supplement, dated December 3, 1985 (Serial No. 85-136A).
5. Letter from Vepco to NRC, Subject: Partial Exemption from General Design Criterion 4 - Request for Additional Information, dated December 27, 1985 (Serial No. 85-136B).
6. Letter from Vepco to NRC, Subject: Partial Exemption from General Design Criterion 4 - Request for Additional Information, dated January 14, 1986 (Serial No. 85-136C).
7. *Amendment to General Design Criterion 4 (GDC-4), 10 CFR Part 50, Appendix A,* published in Federal Register 51 FR 12502, effective May 12, 1986.
8. Letter from Vepco to NRC, Subject: Proposed License Amendment - GDC 4, dated April 30, 1986 (Serial No. 86-245).
9. Letter from NRC to Vepco transmitting Surry Unit 1 and 2 License Amendments No. 108 and related safety evaluations, dated June 16, 1986.
10. Letter from Vepco to NRC, Subject: Generic Letter 87-11, dated September 12, 1988 (Serial No. 88-371).
11. Manual of Steel Construction, 7th Edition, American Institute of Steel Construction.

12. WCAP-18491-P/NP, Revision 0, *Technical Justification for Eliminating Auxiliary Piping Rupture as the Structural Design Basis for Surry Units 1 and 2, Using Leak-Before-Break Methodology*, dated December 2019.

13. Letter from Mark D. Sartain of Virginia Electric and Power Company to the US NRC Document Control Desk, Serial No. 20-091 dated October 22, 2020, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, Request for NRC Approval to Apply Leak-Before-Break Methodology to Reactor Coolant System Branch Pipin*g.

14. Letter from the US NRC to Virginia Electric and Power Company Serial No. 21-297, dated August 20, 2021, *Surry Power Station Units 1 and 2 - Issuance of Amendments Nos. 304 and 304 RE: Leak-Before-Break for Pressurizer Surge, Residual Heat Removal, Safety Injection Accumulator, Reactor Coolant System Bypass and Safety Injection Lines (EPID L-2020-LLA-0255).*

Table 15.6-1
STEAM GENERATOR SUPPORT MATERIALS

Material Specifications	Product Form	Supplemental Requirements	Toughness Tests	Mill Test Reports	NDE
A-352grLC3 mod.	casting	yes	yes	yes	yes
Vascomax CVM 350 & 300	forging	yes	yes	yes	yes
A-106grB	14 in. pipe	none	none	yes	yes

Table 15.6-2
REACTOR COOLANT PUMP SUPPORT MATERIALS

Material Specifications	Product Form	Supplemental Requirements	Toughness Tests	Mill Test Reports	NDE
A-106grB	14 in., 6 in. pipe	none	none	yes	yes
A-105 GR 11	forging	none	none	yes	yes
AlSl-4340	forging, plate	none	none	yes	no
Vascomax CVM 350 & 300	forgings	yes	yes	yes	yes
A-285grC	plate	none	none	yes	no
A-193grB7	bar	none	none	yes	no

Table 15.6-3
SUMMARY OF STRESS FOR FAILURE OF REACTOR COOLANT PUMP SUPPORT DURING NORMAL OPERATION

Location	Loop	Stress (psi)
Steam Generator Outlet	A	20,291
	B	17,388
	C	20,743
Reactor Vessel Inlet	A	16,943
	B	18,337
	C	21,060
Crossover Leg	A	21,940
	B	13,292
	C	20,196
Pressurizer Inlet	C	32,728

Material Properties (A376 Tp 316)

°F	S_{yield}	S_{ult}
100	30 ksi	75 ksi
600	18.8 ksi	71.8 ksi
650	18.5 ksi	71.8 ksi

Figure 15.6-1
REACTOR NEUTRON SHIELD TANK ASSEMBLY

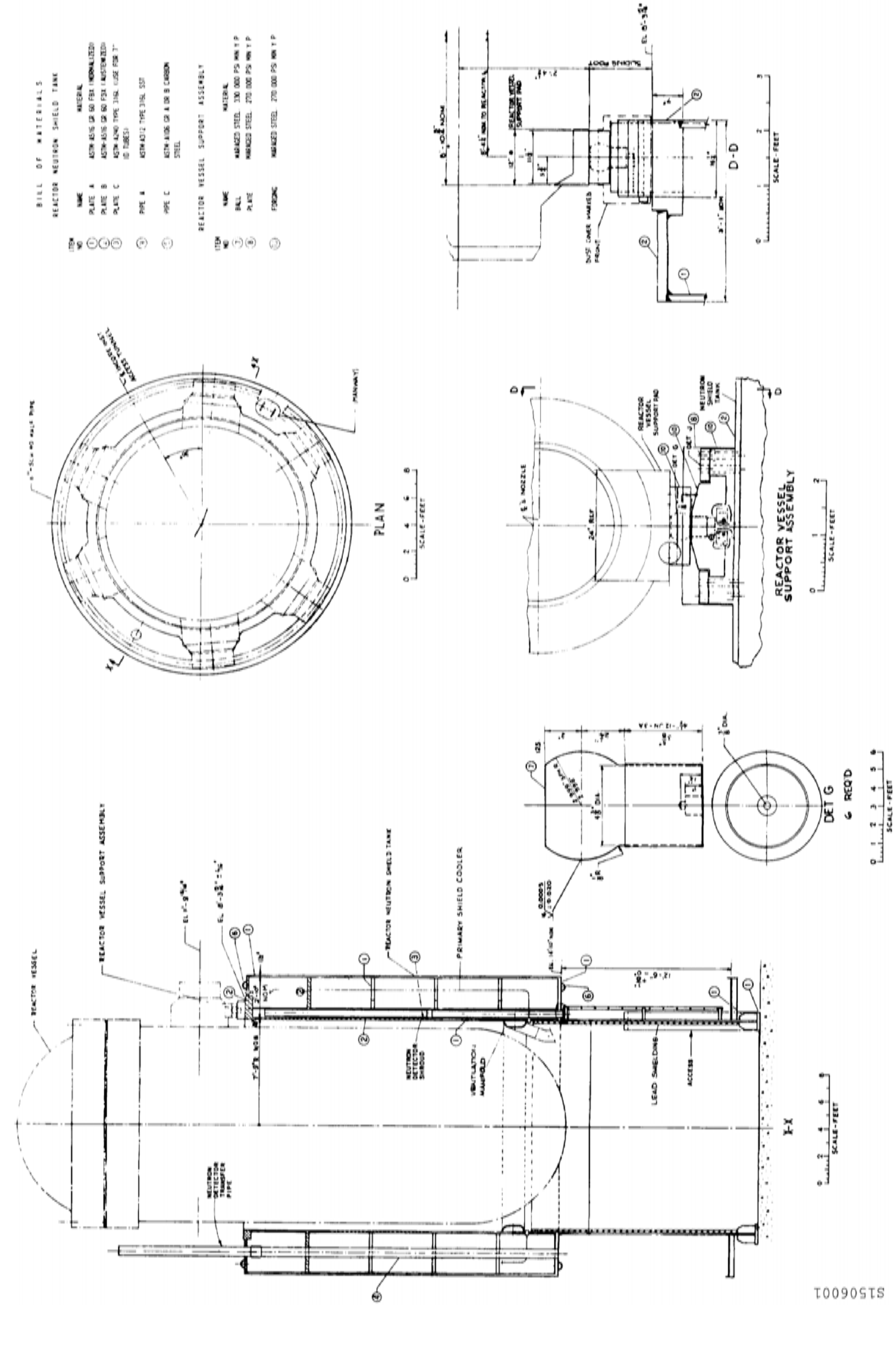
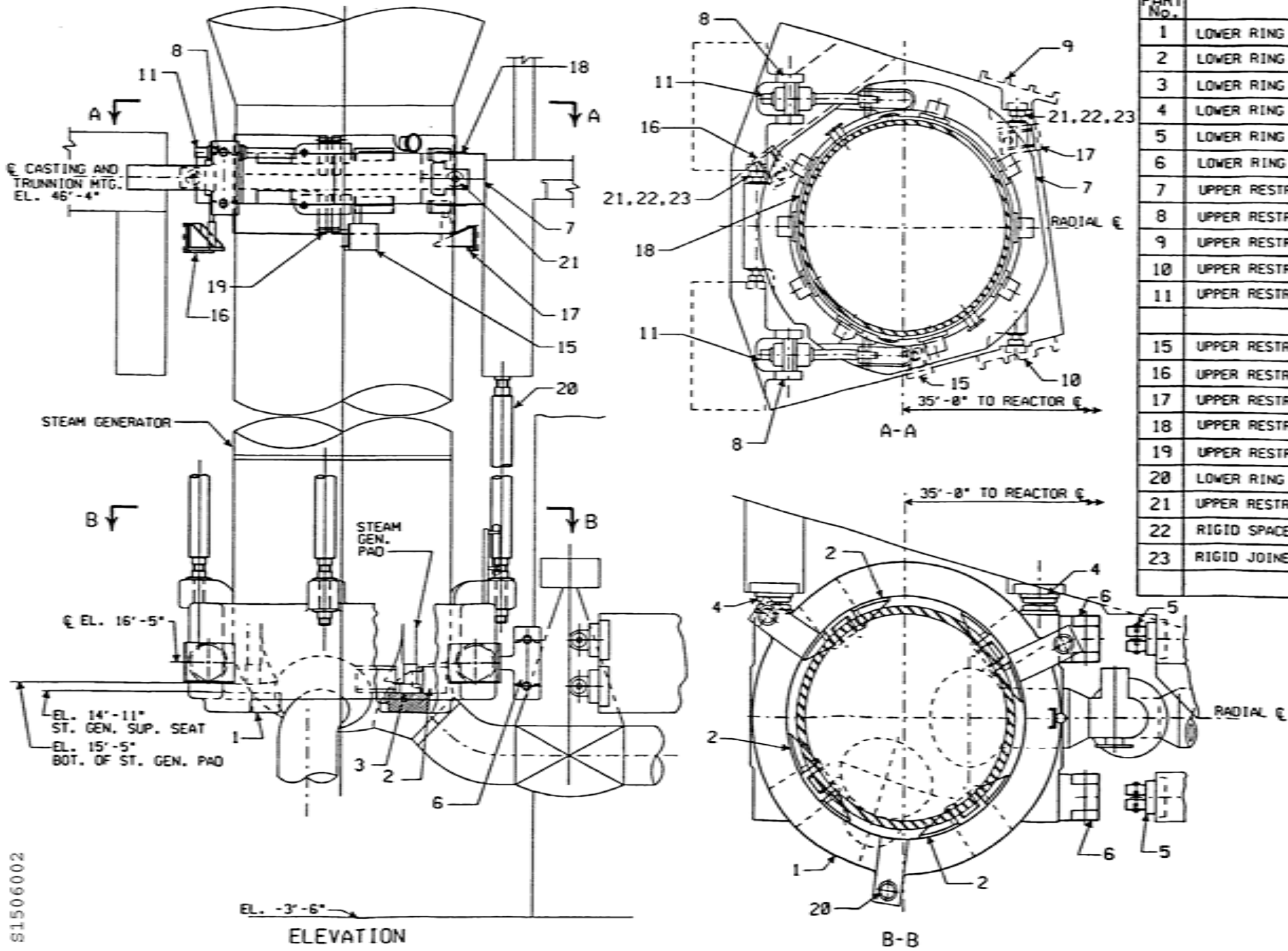


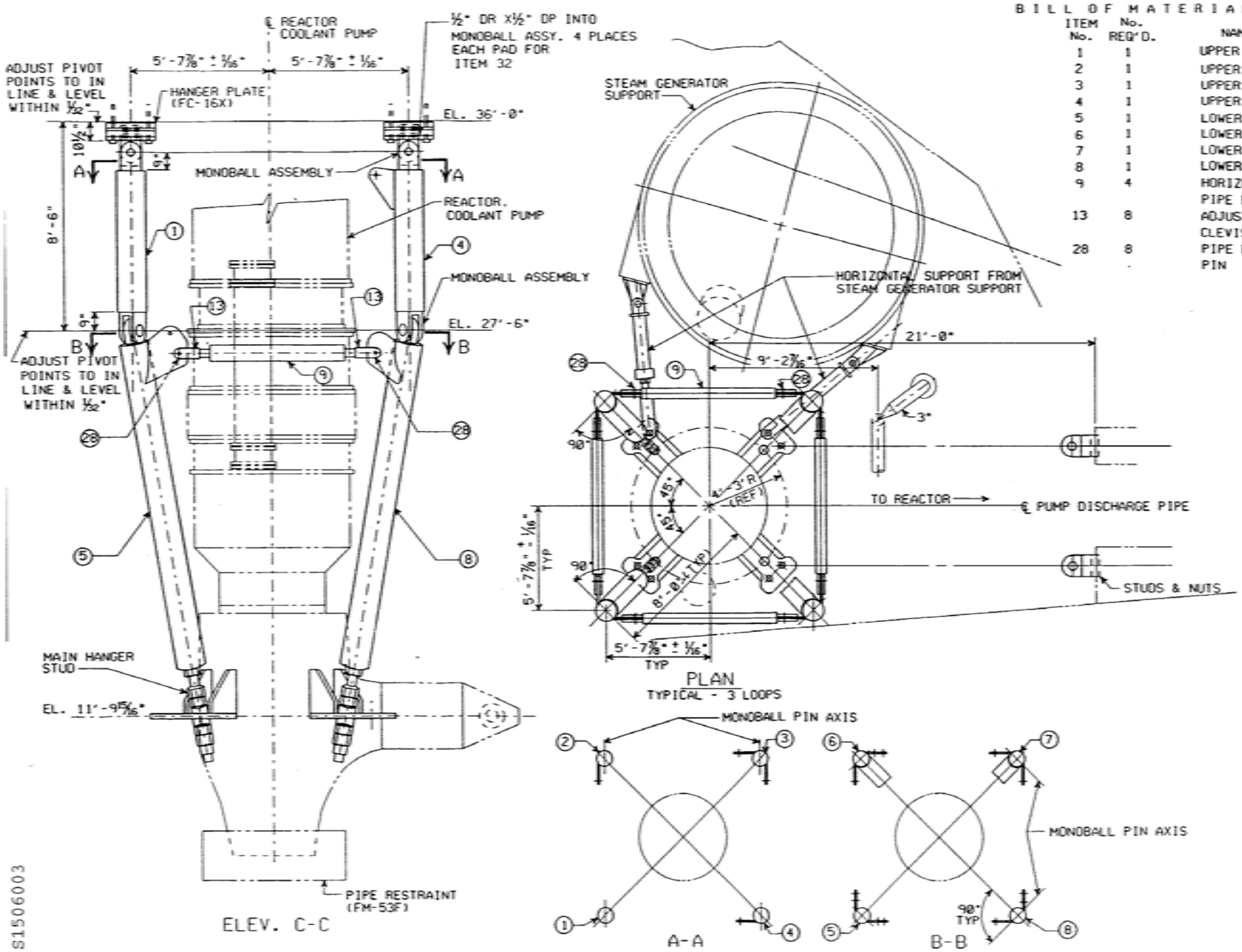
Figure 15.6-2
STEAM GENERATOR SUPPORT ASSEMBLY



PART No.	BILL OF MATERIAL DESCRIPTION	MATERIAL
1	LOWER RING CASTING	STEEL CASTING-ASTM A-352 GRADE LC 3
2	LOWER RING LEG SUPPORT	MARAGED STEEL-FORGING 270,000 PSI MIN. YP
3	LOWER RING BEARING PLATE	MARAGED STEEL 270,000 PSI MIN. YP
4	LOWER RING DOVE-TAIL ASSEMBLY	ASME SA540 150,000 PSI MIN. YP
5	LOWER RING CYL. ROD END CLEVIS	ASTM-A352 GR. LC 3
6	LOWER RING CYL. TRUNNION MOUNT	ASTM-A352 GR. LC 3
7	UPPER RESTRAINT CASTING/CLEVIS	ASTM-A352 GR. LC 3/ AISI 4340, 90,000 PSI MIN. YP
8	UPPER RESTRAINT CYL. TRUNNION MOUNT	ASTM-A352 GR. LC 3
9	UPPER RESTRAINT BEARING PAD/INSERT	ASTM-A352 GR. LC 3/ AISI-A2 TOOL STEEL
10	UPPER RESTRAINT BEARING PAD/INSERT	ASTM-A352 GR. LC 3/ AISI-A2 TOOL STEEL
11	UPPER RESTRAINT SNUBBER CYL.	625 K SHOCK CAPACITY EACH
15	UPPER RESTRAINT SUPPORT No. 1	AISI-C1020 NORMALIZED
16	UPPER RESTRAINT SUPPORT No. 2	AISI-C1020 NORMALIZED
17	UPPER RESTRAINT SUPPORT No. 3	AISI-C1020 NORMALIZED
18	UPPER RESTRAINT UPPER ANCHOR SYS.	4340 NORMALIZED ALLOY STEEL MIN. YP 110,000 PSI
19	UPPER RESTRAINT LOWER ANCHOR SYS.	4340 NORMALIZED ALLOY STEEL MIN. YP 110,000 PSI
20	LOWER RING SUPPORT RODS/HANGER	ASTM-A193 GR. B7/ ASTM-A106 GR. B
21	UPPER RESTRAINT GUIDE	MARAGED STEEL 350,000 PSI MIN. YP
22	RIGID SPACER TUBE	ASTM-A519 GR. 4140 YP 110-140 KSI
23	RIGID JOINER PLATES	ASTM A-36

GENERAL NOTES:
SCALE 3/16" ≈ 1'-0"
3 STEAM GENERATOR SUPPORTS REQUIRED FOR EACH UNIT.

Figure 15.6-3
REACTOR COOLANT PUMP SUPPORTS GENERAL ARRANGEMENT



BILL OF MATERIAL (No. REQ'D. PER SUPPORT)

ITEM No.	No. REQ'D.	NAME	MATERIAL
1	1	UPPER LEG	ASTM-A106 GR. B SCH 160 PIPE
2	1	UPPER LEG	ASTM-A106 GR. B SCH 160 PIPE
3	1	UPPER LEG	ASTM-A106 GR. B SCH 160 PIPE
4	1	UPPER LEG	ASTM-A106 GR. B SCH 160 PIPE
5	1	LOWER LEG	ASTM-A106 GR. B SCH 160 PIPE
6	1	LOWER LEG	ASTM-A106 GR. B SCH 160 PIPE
7	1	LOWER LEG	ASTM-A106 GR. B SCH 160 PIPE
8	1	LOWER LEG	ASTM-A106 GR. B SCH 160 PIPE
9	4	HORIZONTAL PIPE BRACE	ASTM-A106 GR. B SCH 160 PIPE
13	8	ADJUSTABLE CLEVIS	ASTM-A284 GR. D
28	8	PIPE BRACE PIN	AISI 4340 STEEL 150,000 PSI MIN. Y.P.

Figure 15.6-4 (SHEET 1 OF 2)
PRESSURIZER SUPPORT

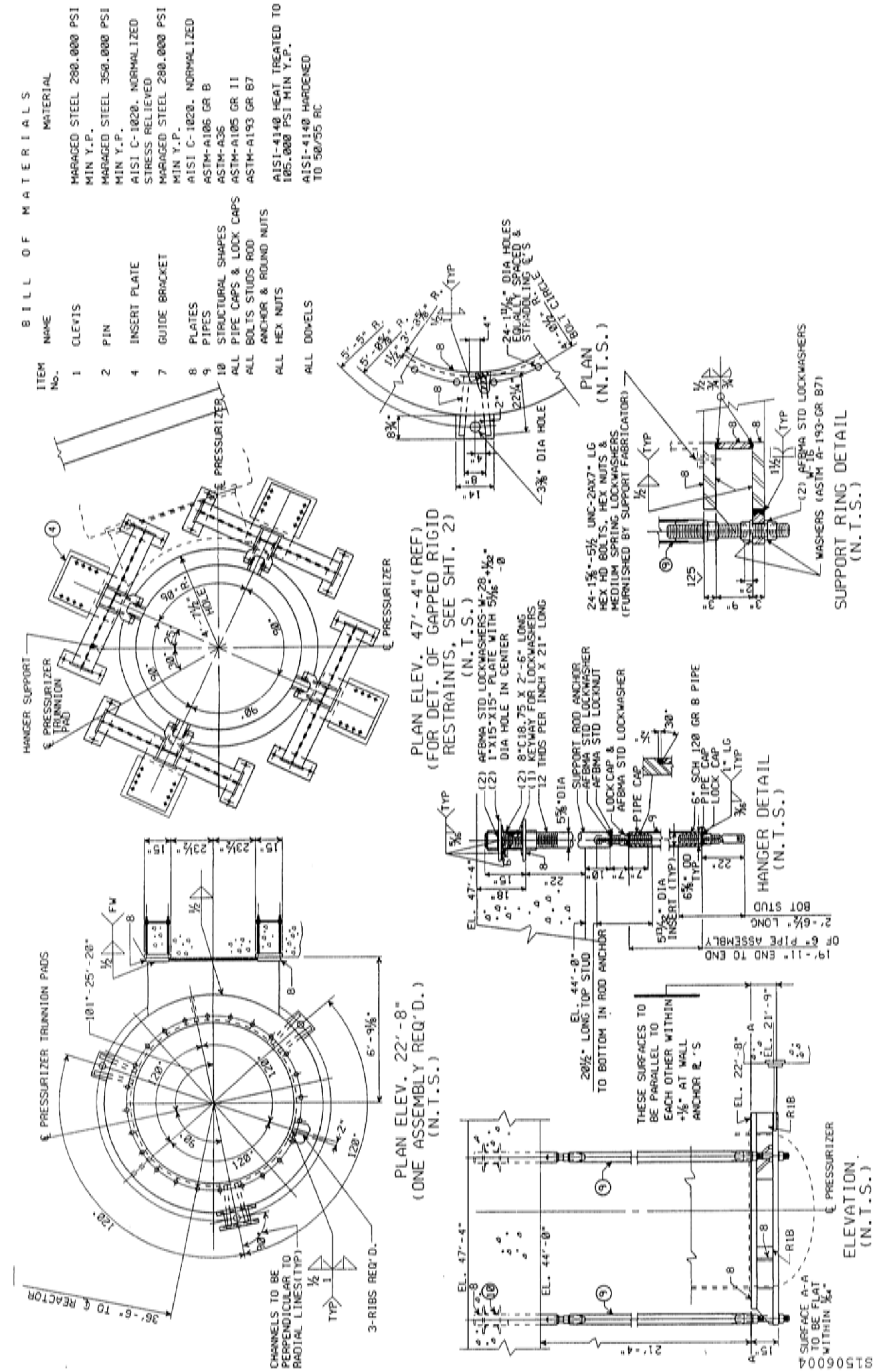
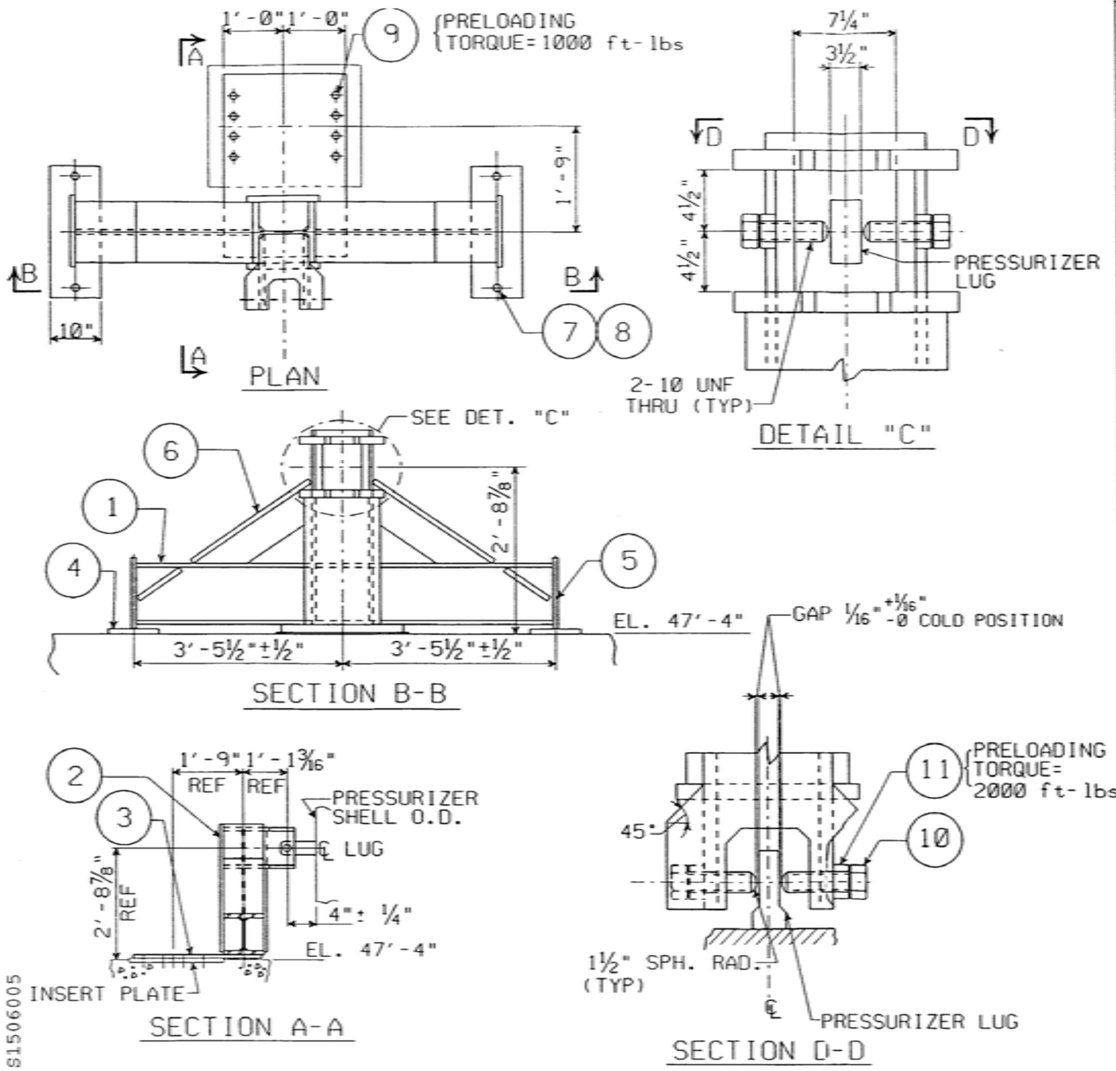


Figure 15.6-4 (SHEET 2 OF 2)
PRESSURIZER SUPPORT



MATERIAL LIST			
ITEM	QTY	DESCRIPTION	MAT'L.
1	1	W12X65X6'-10" LG.	A36
2	1	W12X65X2'-1½" LG.	A36
3	1	PL 1½"X2'-0"X3'-6"	A36
4	2	PL 1"X10"X2'-1½"	A36
5	2	PL 1"X14"X12"	A36
6	2	WT6X32.5	A36
7	4	DRILLCO BOLT MB-750-14"-9¼" W/2 NUTS & 2 WASHERS & ITEM 8	N/A
8	4	PL WASHER ½"X2½"X2½" W/⅞"ø HOLE	A36
9	8	1-8UNC-3A, 3" LG.	A540 GR. B23 CL3
10	2	HEX BOLT 2-10UNF-2AX5½"LG. MACHINE AS SHOWN	A540 GR. B23 CL3
11	2	HEX NUT 2-10 UNF-2B	A-194 GR. 2H

TYP. DET.-GAPPED
RIGID RESTRAINT
UNIT #2 CONFIGUATION AS SHOWN
UNIT #1 LOWER BEAMS DIFFERENT

Intentionally Blank

15.7 MASONRY WALLS

Concrete masonry walls are used throughout the plant to provide barriers for radiation shielding, fire protection and personnel separation. Those walls utilized in the construction of Seismic Class I structures are not designed or intended to act as bearing or for transmitting building shear forces. These walls are not used as major load-bearing walls and are not included as part of the overall building shear wall system.

All of the concrete masonry walls that are in proximity to or have attachments for safety-related or equipment such that wall failure could affect a safety-related system were identified and analyzed in accordance with the requirements of IE Bulletin 80-11 (Reference 1). The reevaluation of the masonry walls was performed based upon criteria for reevaluating concrete masonry walls submitted in Reference 2, which uses as its acceptance criteria the allowable stresses specified in ACI-531-79, *Building Code Requirements for Concrete Masonry Structures.* Review of test data and the literature substantiates the use of these allowable stresses. The review also included research of acceptable damping percentages, analysis techniques, in-plane effects, arch action and local stress valves.

The reevaluation criteria considered loads from both safety- and non-safety-related attachments as well as relative interstory displacements between building elevations where applicable. All applicable loads and load combinations specified in the Surry FSAR for concrete design were included in the reevaluation. A review of the walls determined that the walls are not subjected to tornado missiles or depressurization, pipe whip or jet impingement loads. The global review of the walls included seismic inertia loads, interstory displacement loads for both in-plane and out-of-plane effects, equipment loads, and wind loads where applicable.

The local review included discontinuities such as openings and the mechanism for local load transfer into the walls. This included a review of potential local block pull out as well as possible overstress within individual blocks due to attached equipment. Multiwythe walls were also reviewed to ensure the integrity of the collar joint. Calculated shear and tension stresses across the collar joints were compared against allowable values that were conservatively chosen to account for potential small areas of voids or other discontinuities.

At the completion of the response to IE Bulletin 80-11, all identified masonry block walls were evaluated and, modified, as required, to meet the acceptance criteria. The results of this reevaluation program were transmitted to the Nuclear Regulatory Commission. The analysis results of the masonry wall reevaluation program indicated that of the walls requiring reanalysis, 79 walls were acceptable, two walls were acceptable after equipment was removed from the wall, and 31 walls were modified to meet acceptance criteria. Seven safety-related masonry walls in the fuel building were not acceptable under extreme loading conditions and were replaced with blow-off siding. An additional 217 non-safety related walls were also reviewed to ensure that they did not endanger safety-related equipment. Following the approval of responses to IE Bulletin 80-11 by the Nuclear Regulatory Commission, all subsequent modifications involving masonry block walls are evaluated under the Nuclear Design Control Program, which continues to invoke the technical requirements of IE Bulletin 80-11 (References 3 & 4).

15.7 REFERENCES

1. IE Bulletin 80-11, *Masonry Wall Design*, Nuclear Regulatory Commission, Office of Inspection and Enforcement, May 8, 1980.
2. Letter from B.R. Sylvia, VEPCO, to James P. O'Reilly, NRC. November 3, 1980, *IE Bulletin No. 80-11 Interim Report, Surry Power Station Units 1 & 2, North Anna Power Station Units 1 & 2*, Serial No. 878.
3. Letter from Chandu P. Patel, NRC, Office of Nuclear Reactor Regulation, *Masonry Wall Design, IE Bulletin 80-11 Surry Power Station Unit Nos. 1 and 3 (TAC Nos. 42867 and 42868)*, August 11, 1988, Serial No. 88-551.
4. Letter from Bart C. Buckley, NRC, Office of Nuclear Reactor Regulation, *Surry Units 1 and 2 - Safety Evaluation Masonry Wall Design, IE Bulletin 80-11, (TAC Nos. 42867 and 42868)*, October 2, 1989.

Appendix 15A
Seismic Design for the Nuclear Steam Supply System and Miscellaneous Components

Intentionally Blank

APPENDIX 15A SEISMIC DESIGN FOR THE NUCLEAR STEAM SUPPLY SYSTEM AND MISCELLANEOUS COMPONENTS

15A.1 GENERAL SEISMIC DESIGN CRITERIA FOR THE NUCLEAR STEAM SUPPLY SYSTEM

This Appendix is based on Appendix B to the initial FSAR.

All Class I components of the nuclear steam supply system are designed in accordance with the following criteria:

1. Primary operating stresses, when combined with the operating-basis earthquake seismic stresses resulting from a dynamic analysis using a response spectrum normalized to a maximum horizontal ground acceleration of 0.07g and a simultaneous vertical ground acceleration of two-thirds the horizontal, are maintained within the allowable stress limits in Table 15A-1.
2. Primary operating stresses when combined with the design-basis earthquake seismic stresses resulting from a dynamic analysis using a response spectrum normalized to a maximum horizontal ground acceleration of 0.15g and a simultaneous vertical ground acceleration of two-thirds of the horizontal, are limited so that the function of the component or system shall not be impaired, preventing a safe and orderly shutdown of the unit. Further, the primary operating stresses are maintained within the allowed stress limits in Table 15A-1.

   “No loss of function” requires that rotating equipment will not seize, pressure vessels will not rupture, and supports will not collapse or deform to such a degree as to cause failure of the supported equipment. In addition, systems required to be leaktight will remain leaktight, and engineered safeguards will perform intended functions.

15A.2 SEISMIC DESIGN CRITERIA FOR PIPING, VESSELS, SUPPORTS AND REACTOR VESSEL INTERNALS

Following discussions with the Staff of the Atomic Energy Commission (AEC) Division of Reactor Licensing during the Construction Permit Application Review for Diablo Canyon Unit 1, the criteria presented in WCAP-5890, Revision 1 (Reference 1), for the generation of limit curves were modified. Details of the manner in which this modification was developed are given in Section 15A.5.1.

The loading conditions employed in the design of Class I piping, vessels, and supports are enumerated and defined in Section 15A.2.1. The allowable stress limits associated with the various loading conditions are shown in Table 15A-1. Since the reactor vessel internals must also satisfy deformation limits to be able to perform their function, i.e., allow core shutdown and cooling, the vessel internals are discussed separately in Section 15A.2.3.

15A.2.1 Loading Condition Definitions

The loading condition definitions given below are taken from Section III of the ASME Boiler and Pressure Vessel Code, Summer 1968 Addenda.

15A.2.1.1 **Normal Conditions**

Any condition in the course of system start-up, operation in the design power range, and system shutdown, in the absence of upset, emergency or faulted conditions.

15A.2.1.2 **Upset Conditions**

Upset conditions are any deviations from normal conditions anticipated to occur often enough that design should include a capability to withstand the conditions without operational impairment. The upset conditions include those transients which result from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, transients due to loss of load or power, and any system upset not resulting in a forced outage. The estimated duration of an upset condition shall be included in the design specifications. The upset conditions include the effect of the operating-basis earthquake for which the system must remain operational or must regain its operational status.

15A.2.1.3 **Emergency Conditions**

Any deviations from normal conditions which require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurrence but are included to provide assurance that no gross loss of structural integrity will result as a concomitant effect of any damage developed in the system.

15A.2.1.4 **Faulted Conditions**

Those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the nuclear energy system may be impaired to the extent where considerations of public health and safety are involved. Such considerations require compliance with safety criteria as may be specified by jurisdictional authorities. Among the faulted conditions may be a specified design-basis earthquake for which safe shutdown is required.

15A.2.2 Piping, Vessels, and Supports

The reasons for selection of the above-mentioned loading conditions and allowable stress limits are as follows:

1. When subjected to the operating-basis earthquake, the nuclear steam supply system is designed to be capable of continued safe operation. Equipment and supports needed for this purpose are required to operate within normal design limits, as shown in Table 15A-1. The load combination corresponding to the upset loading condition is the normal load, plus the operating-basis earthquake load.
2. In the case of the design-basis earthquake, it is necessary to ensure that components required to shut the unit down and maintain it in a safe shutdown condition do not lose their capability to perform their safety function. This capability is ensured by maintaining the emergency stress limits as shown in Table 15A-1.
3. For the highly unlikely but postulated case of pipe rupture, a reactor coolant branch or other potentially governing break, the effects of the pipe rupture will not cause failure propagation to the reactor coolant piping. The load combination corresponding to the faulted loading condition is the design-basis earthquake and/or design-basis accident load.
4. For the extremely remote event of simultaneous occurrence of a design-basis earthquake and postulated pipe rupture of a reactor coolant system branch line or other potentially controlling break, the Class I piping and component are checked for no loss of function, i.e., the capability to contain fluid, allow fluid flow, and perform vital engineered safeguards functions. This is ensured by limiting the various stress combinations within the faulted condition design limits shown in Table 15A-1.

The minimum margin of safety between the design limit stress and the expected collapse condition is for the case of pure tension, and is defined as:

$$\frac{S_{ultimate} - S_{design}}{S_{design}}$$

Under more realistic operating conditions, piping and vessels will always experience some combination of tension and bending. For these combined load cases, the margin of safety is greater than that for pure tension, as shown by the limit curves contained in WCAP-5890, Rev. 1, and shown in Figures 15A-4 and 15A-5. Therefore, it is conservative to base the margin of safety on pure tension. Table 15A-2 illustrates the margin of safety between the stress limits for various load conditions and the expected failure or collapse condition for typical materials.

Plastic or limit analyses conducted within the limits of the faulted condition were performed considering plastic material behavior, including, as required, modifications of material stiffness characteristics, formation of plastic hinges and other non-linear effects, as determined in detailed structural analysis, and provided in standard stress reports.

15A.2.3 Reactor Vessel Internals

15A.2.3.1 Design Criteria for Normal Operation

The internals and core are designed for normal operating conditions and subjected to loads of mechanical, hydraulic, and thermal origin. The response of the structure under the operating-basis earthquake is included in this category as well as operational transients (upset conditions).

The stress criteria established in Section III of the ASME Boiler and Pressure Vessel Code, Article 4, have been adopted as a guide for the design of the internals and core, with the exception of those fabrication techniques and materials not covered by the Code, such as the fuel rod cladding. Seismic stresses are combined in the most conservative way and are considered primary stresses.

The members are designed under the basic principles of: (1) maintaining deflections within acceptable limits, (2) keeping the stress levels within acceptable limits, and (3) preventing fatigue failures.

15A.2.3.2 Design Criteria for Abnormal Operation

The abnormal design condition assumes blowdown effects due to a pipe break[1] combined (by SRSS combination) in the most unfavorable manner with the effects associated with the design-basis earthquake.

For this condition, the criteria for acceptability are that the reactor is capable of safe shutdown and that the engineered safety features are able to operate as designed. Consequently, the limitations established on the internals for these types of loads are concerned principally with the maximum allowable deflections. Additional stress criteria for critical structures under normal operation, plus the design-basis earthquake and blowdown excitation, ensure that the structural integrity of the components is maintained.

15A.3 GENERAL ANALYTICAL PROCEDURE FOR SEISMIC DESIGN

The design and analysis of Class I components of the nuclear steam supply system utilizes the “response spectrum” approach.

---

1. As discussed in Section 15.6.2, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop piping. However, pipe ruptures of reactor coolant branchlines are still postulated.

The dynamic analysis is performed using the normal mode methods. The inertial properties of the models are characterized by the mass and mass moment of inertia of each mass point. The stiffness properties are characterized by the moment of inertia, area, shear shape factor, torsion constant, Young's modulus, and shear modulus.

Table 15.2-2 gives the damping ratios to be used in the dynamic analysis of components.

15A.3.1 Mechanical Equipment

The Westinghouse-supplied Class I mechanical components for Surry that require a seismic analysis were determined and checked for seismic adequacy by employing the following procedure:

1. The manufacturer's drawings were reviewed to classify the component.
    a. If the component fell within a category that was previously analyzed using a multi-degree-of-freedom model and shown to be relatively rigid, then a static seismic analysis was performed to check equipment seismic adequacy.
    b. If the component could not be categorized as similar to previously analyzed components, then a seismic modal analysis was performed, using multi-degree-of-freedom dynamic models.
2. Stresses and deflections were checked to ensure that they were within allowable limits and did not result in loss of function.

Typical Class I mechanical equipment of the engineered safety feature (ESF) systems supplied by Westinghouse was originally analyzed on a worstplant basis using a multi-degree-of-freedom modal analysis. The term "worstplant basis" is defined, for the particular component in question, as the most severe seismic response spectra applicable to any Westinghouse plant employing that particular piece of equipment. All contributing modes were considered. A sufficient number of masses was included in the mathematical models to ensure that coupling effects of members within the component were properly considered. The results of these analysis indicated that the models contained more masses than necessary, and that future analyses of comparable equipment could be considerably simplified by considering fewer masses, or merely performing a simple static analysis.

The method of dynamic analysis used a proprietary computer code called WESTDYN. This code uses inertia values, member sectional properties, elastic characteristics, support and restrain data characteristics, and the appropriate seismic response spectrum as input. Both horizontal and vertical components of the seismic response spectrum are applied simultaneously. The modal participation factors are combined with the mode shapes and the appropriate seismic response spectra to give the structural response for each mode. The internal forces and moments are computed for each mode from which the modal stresses are determined. The stresses are then summed using the square-root-sum-of-squares method, except for the major components in the reactor coolant loop. As discussed in Section 15A.3.3, for the reactor coolant loop analysis, the combination of modal responses for closely spaced modes is performed using the grouping methodology in Regulatory Guide 1.92.

In analyzing equipment to resist seismic loads, the vertical seismic spectrum, equal to two-thirds of the horizontal response spectrum, is used to determine the acceleration appropriate to the vertical frequency. An idealized umbrella spectrum was used in the analyses. The floor response spectra at the Surry site are encompassed by the umbrella spectrum used in the dynamic analysis of Westinghouse-supplied equipment.

Typical Class I engineered safeguards tanks supplied by Westinghouse, e.g., for boric acid, accumulator, and boron injection, were analyzed using the method above, with the combined horizontal and vertical seismic excitation occurring simultaneously in conjunction with normal loads. Hydrodynamic analyses of these tanks have been performed using the methods described in TID 7024 (Reference 2).

Selected critical Class I ESF valves supplied by Westinghouse have been analyzed using the above method, and the results indicate that their fundamental natural frequency is sufficiently separated from the building frequency. The results indicate that the total stress, considering all modes, is far below the allowable stress limit. Motors attached to motor-operated valves have been included in the mathematical models.

The deflections and stresses obtained from the seismic analysis are added to the deflections and stresses associated with the operational mode of the mechanical equipment to verify that clearances are not exceeded and the stresses are within allowable limits. This criterion ensures that this equipment will perform the intended function under seismic conditions.

All mechanical equipment analyzed had fundamental modes in the rigid range, with the exception of loop stop valves and some vertical tanks.

The fundamental frequency of vertical tanks and the loop stop valves was greater than 9 Hz, which is outside the resonance range of the structures in which they are housed. The component supports were modified to remove the fundamental frequency of the item from the resonance range of the structure, by providing stiffer supports to increase the fundamental frequency of the component. The selection of the type of restraint used was dependent upon the component analyzed and the structure surrounding the component.

Restraints, snubbers, or other devices are not used to preclude resonance of the electrical and control systems equipment for seismic loading. Protection system equipment that is typical of the design has been subject to tests under simulated seismic accelerations to demonstrate the ability to perform and complete its function. These data are contained in WCAP-7397-L (Reference 3).

The seismic loads for the design and analysis of Class I mechanical components, including pumps, valves, heat exchangers, and tanks within Stone & Webster's scope of responsibility, were based on the ground response spectra (GRS) shown in Figures 2.5-5 and 2.5-6 or amplified floor response spectra (ARS), depending on their location. Seismic loads were developed for the operating-basis earthquake (OBE) and the design-basis earthquake (DBE). The spectra used in the evaluation of Class I mechanical components were based on damping values consistent with those indicated in Table 15.2-2. Where applicable, seismic loads were combined with the results from other load cases such as thermal and dead load. Constraints such as snubbers or other appropriate devices are utilized wherever necessary to meet design requirements.

All Class I mechanical components are designed to withstand the operating-basis earthquake and to function through the design-basis earthquake to safe shutdown. Vendors supplying the components are required by specification to design the components to function, as outlined above, under the seismic loadings. The vendor is required to validate component integrity under the specified seismic conditions.

15A.3.2 Earthquake Experience-Based Method Developed for Unresolved Safety Issue (USI) A-46 for Seismic Verification of Equipment

In response to U.S. Nuclear Regulatory Commission Generic Letter 87-02 on USI A-46, *Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors,* a Generic Implementation Procedure (GIP) was developed by the Seismic Qualification Utilities Group (SQUG). The criteria and methodology in Revision 3 of the GIP (Reference 40), as modified and supplemented by the NRC Supplemental Safety Evaluation Reports (SSERs) 2 and 3 (References 44 & 45) may be used, with certain additional considerations, as an alternative to other licensing basis methods for seismic design and verification of existing, modified, new and replacement equipment classified as safety-related, NSQ or seismic category 1. Considerations that are additional to the GIP pertain to the following issues:

- Use of GIP Method A for estimating seismic demand.
- Additional criteria applicable for the design and analysis of new flat bottom vertical tanks.
- Applicability of Part II, Section 5 of the GIP for conduit and cable tray raceways.
- Use of criteria associated with damping values, static coefficient and expansion anchor safety factors for equipment anchorage evaluations conforming to the current, conservative, licensing basis commitments.
- Documentation of the results of the Screening Verification and Walkdown in Section 4.6 of the GIP may be limited to the use of walkdown checklists. It is not necessary to complete the Screening Verification Data Sheets (SVDS).

- It is not necessary to identify “essential relays” and perform functionality screening as defined in Section 6 of the GIP. Relays designated as Class 1E are evaluated by comparing seismic capacity to seismic demand.

- The GIP method is generally applicable only for equipment located in mild environment. However, with case-by-case justification, it may be used for equipment in harsh environment.

Guidance for the use of the GIP for the seismic design and verification of mechanical and electrical equipment, including a discussion of the above exceptions, is provided in an engineering procedure (Reference 62).

15A.3.3 Reactor Coolant Loops and Supports

The original configuration of the reactor coolant system equipment supports included ten large-bore hydraulic snubbers per loop to carry the loads from postulated pipe ruptures of the reactor coolant system, main steam line, and feedwater line. Subsequent fracture mechanics analyses, submitted to the NRC on behalf of the Westinghouse Owners Group, demonstrated that the probability of rupture of the primary coolant loop is extremely small, and that the presence of a pipe crack could be detected by leakage well before the crack grew to a critical size which would cause rupture. NRC Generic Letter 84-04 (Reference 4) provided the NRC staff safety evaluation of these “leak-before-break” analyses, concluding that, provided certain specific conditions are met, the dynamic effects of a postulated pipe break in the reactor coolant system primary loop need not be considered as a design basis for the reviewed plants, including Surry Units 1 and 2. Subsequently, Generic Letter 87-11 (Reference 5) eliminated the need to postulate Arbitrary Intermediate Breaks and allowed removal of the associated pipe whip restraints and jet impingement shields. Because the stresses in the main steam lines inside containment are well below the stress criteria for required mandatory intermediate breaks, the only breaks which need be postulated are terminal end breaks which do not apply lateral loads to the steam generator. Based on the relief provided by these two relaxations of criteria, the reactor coolant system supports have been modified to eliminate eight of the ten large-bore snubbers per loop of the reactor coolant system. These efforts are discussed in Section 15.6.2; additional information is contained in References 6-15.

The reactor coolant loop system was re-evaluated with the snubbers eliminated to assure that the conditions of pressure, deadweight, thermal, seismic, and remaining pipe rupture effects, would not result in unacceptable stress levels or factors of safety. Two essentially independent analyses of a representative single primary loop were performed by Westinghouse Electric Corporation and Stone & Webster Engineering Corporation, in accordance with the original division of design responsibilities. Westinghouse performed deadweight, pressure, thermal and seismic analyses using a simplified model as the run of record to obtain piping stresses. Stone & Webster performed analyses using a model incorporating a detailed representation of the support members, principally to obtain component support loads under normal and accident loadings. Both analytical and models were revisions to existing models and incorporated changes due to the steam generator replacements as well as the snubber elimination efforts.

These analyses incorporated the loads from deadweight, internal pressure, thermal expansion, seismic events (OBE and DBE), and the dynamic effects of pipe ruptures of other systems (controlling breaks, for example), in the main steam line, pressurizer surge line, main feedwater line, etc.) No other hydraulic transient loading was considered as significant.

For seismic analysis, the soil structure interaction amplified response spectra for 0.5 percent critical equipment damping (OBE) and 1 percent equipment damping (DBE) were used with appropriate “bump” factors as discussed in Section 15A.3.5.3. These damping values are lower than those in Regulatory Guide 1.61, *Damping Values for Seismic Design of Nuclear Power Plants* and in ASME Code Case N-411, *Alternative Damping Values for Seismic Analysis of Classes 1, 2, and 3 Piping.* The vertical and horizontal earthquake responses were combined for piping analysis as described in Section 15A.3.3. For component support analysis, the responses to the three directions of earthquake loading were combined by SRSS. The combination of modal responses for closely spaced modes was performed using the grouping methodology in Regulatory Guide 1.92.

The Westinghouse analysis used the WESTDYN code and a simplified representation of the component supports as stiffness matrices. The component support stiffness matrices were supplied by Stone & Webster. The WESTDYN computer code has been utilized on numerous Westinghouse plants, and was reviewed and found acceptable by the NRC for the Surry units in 1974. A detailed description of the WESTDYN method of analysis is given below.

The code uses as input system geometry, inertia values, member sectional properties, elastic characteristics, support and restraint data characteristics, and the appropriate Surry seismic response spectrum of 0.5% critical damping. Both horizontal and vertical components of the seismic response spectrum are applied simultaneously.

With these input data, the overall stiffness matrix [K] of the three-dimensional piping system is generated (including translational and rotational stiffness). Restraints are deleted, and the stiffness matrix is inverted to give the flexibility matrix [F] of the system.

$$[F] = [K]^{-1}$$

A product matrix is formed by the multiplication of the flexibility and mass matrices. This product matrix forms the dynamic matrix [D] from which the modal matrix is computed.

$$[D] = [F]\,[M]$$

The modal spectral matrices are generated using a modified Jacobi method.

$$(\omega^2\,[M] - [K])\,X = O$$

From this information, the modal participation factor is combined with the mode shapes and the appropriate seismic response spectra to give the structural response for each mode.

The Stone & Webster analysis used the STARDYNE computer code and a model incorporating a detailed representation of the support members. STARDYNE is a public domain computer program and is recognized as a Category 1 computer program suitable for nuclear safety-related work. The program used is maintained under Stone & Webster's Quality Control procedures. The following modules of STARDYNE, Version 3, Level H, were used:

- STAR (Static and Modal Extraction Analysis)
- DYNRE4 (Seismic Response Spectrum Analysis)
- DYNRE6 (Time History Transient Analysis)—used only for evaluating pipe rupture loadings

Dynamic analyses were performed of the controlling pipe ruptures in the pressurizer surge line, main steam line, and main feedwater lines. The originally-postulated terminal and intermediate breaks were reviewed by Stone & Webster to determine those breaks which would cause the most severe loadings on the revised support configuration with snubbers removed. Time-history forcing functions were applied to the detailed model representing these potentially limiting breaks, to obtain maximum member loads with the revised support configuration. These loads were combined by SRSS with the seismic DBE loads and then summed with deadweight and pressure loads.

The results of the two independent analyses with revised support configuration established that the frequencies of most vibrational modes are virtually unchanged by the snubber eliminations. Comparison of the interface loads calculated by the two models was performed to ensure that the results of the two models were consistent; the significant interface loads were found to be within 15%, which is considered to be good agreement. The analyses demonstrated that the piping components and supports are stressed within acceptable limits, and adequate safety margins exist in a seismic event. The maximum level of stress (percentage) compared to the Code allowable at the highest stress point in each leg of the reactor coolant loop for thermal, deadweight, and seismic conditions are given in Table 15A-5.

In addition, the maximum resultant bending moment in the primary coolant loop piping under combined deadweight, pressure, thermal, and design basis seismic loadings is 28,860 inch-kips. This value is less than the enveloped value in the Westinghouse topical report, WCAP-9558, Revision 2 (Reference 6), and also less than 42,000 inch-kips which was identified in NRC Generic Letter 84-04 as the maximum allowable moment for the Westinghouse Owner's Group plants for justifying that pipe rupture need not be postulated in the primary reactor coolant loop piping.

For combined normal operating and seismic loads, the location of the maximum stress is the steam generator outlet elbow; for the main steam line rupture loading, the location of maximum stress is in the steam generator inlet elbow; for the pressurizer surge line break, the maximum stress occurs in the hot leg where the surge line intersects.

Stone & Webster evaluated the calculated maximum loadings on the supports of the modified support configuration with eight of the large-bore snubbers eliminated. The factors of safety (allowable load/combined load) for the combined deadweight, pressure, thermal, and design basis seismic loads are given in Table 15A-6. Similar factors of safety under the combined deadweight, pressure, thermal, and SRSS combination of design basis seismic loads plus maximum pipe rupture loads, are given in Table 15A-7. These tables demonstrate that adequate factors of safety exist under all loading conditions.

The results of these analyses confirm that the large-bore snubber eliminations do not compromise the bases for the previous leak-before-break analysis, namely:

1. The loading on the primary loop piping is still enveloped by the generic analyses submitted on behalf of the A-2 Owners Group and accepted by the NRC staff in Generic Letter 84-04, and specifically for Surry by NRC letter dated June 16, 1986; and

2. The reactor coolant system equipment, piping, and supports continue to have acceptable margins of safety under licenced loading conditions other than the now-eliminated ruptures of the primary loop piping and Arbitrary Intermediate Break of the main steam lines.

The inertial forces and moments are computed for each mode from which the modal stresses are determined. The stresses are then summed using the square-root-sum-of-squares method.

The maximum stresses in the reactor coolant loop piping imposed by the normal loads plus loads associated with the design-basis earthquake are below the allowable stress limit. The stress levels in the reactor coolant loop piping are provided in Table 15A-7 (References 9 and 11).

As noted in Section 15.6.2 and its associated references, the application of Leak-Before-Break was subsequently extended to the Surry Units 1 and 2 Reactor Coolant System branch piping including: the Pressurizer Surge, Residual Heat Removal, Accumulator, Loop Bypass, and Safety Injection piping up to each line’s first pressure isolation valve. The evaluation demonstrated the dynamic effects of the pipe rupture resulting from postulated breaks in the Surge, RHR, Accumulator, Loop Bypass and SI line piping need not be considered in the structural design basis of Surry Units 1 and 2 for the 80 year period of extended plant operations.

15A.3.4 Anchor Bolts

The majority of anchor bolts originally installed at the Surry Power Station were shell-type Phillips self-drilling anchors. A minimum safety factor of four was used. Cyclic loads and the effect of baseplate flexibility were not specifically considered; however, supports, baseplates, and anchor bolts were designed to withstand the maximum force exerted by seismic and thermal conditions.

In response to IE Bulletin 79-02 (Reference 16), all pipe support baseplates were analyzed considering baseplate flexibility, and modifications were made when baseplates and/or anchor bolts were found inadequate. Wedge-type Hilti bolts were installed in accordance with manufacturer's requirements based on onsite testing conducted by Hilti, Inc.

A finite element analysis was performed using the ANSYS computer program as provided by an owner's group organized by Teledyne Engineering Services. A description of this program was submitted to the NRC as Technical Report TR-3501-1, Revision 1 (Reference 17). In some cases where the support plate could not be modeled in the computer program, hand calculations were performed, allowing sufficient margin for baseplate flexibility and prying action.

The factors of safety of four for wedge-type anchors and five for shelltype anchors were used to determine the anchor bolt allowable loads for the reanalysis. All baseplates were reanalyzed to ensure that these factors of safety were met. Where the factors of safety were not met by analysis, modifications were provided to ensure the appropriate factor of safety. The original design for anchor bolts at Surry was based on a factor of safety of four for all anchor bolts, based on a design concrete strength of 3000 psi. In conjunction with IE Bulletin 79-02, a concrete inspection program was performed to demonstrate a concrete strength of 4000 psi, which would provide the factor of safety of five required by the Bulletin. Thirty-two Windsor probe tests were performed at various locations throughout the plant (Surry Units 1 and 2) to provide data for the evaluation. The results of this program show a 95% confidence level of at least 4000 psi concrete. Therefore, the analysis was based on 4000 psi concrete with the factors of safety of four and five required by Bulletin 79-02.

No special design requirements for the anchor bolts to withstand cyclic loads were applied. Testing performed for the owner's group, the results of which are presented in Technical Report TR-3501-1 indicates that cyclic loading on the anchors does not result in a general reduction of the ultimate capacity of the anchor. Bolts for shell-type anchors (Phillips Red-Head self-drilling anchors) were tightened snugly, but were not preloaded. Wedge anchors (Hilti bolts) were preloaded to the design allowable load.

To ensure that the design requirements have been met for the installed anchor bolts, an inspection and testing program was conducted. Under this program, one anchor bolt per accessible base plate was inspected and tension tested to at least the anchor bolt design load. Anchor bolt installations which were suspect based on the visual inspection were tension tested to at least the anchor bolt design allowable load (20% of the manufacturer's ultimate) and evaluated for a factor of safety of five by tension testing to five times the design load, or determining the anchor capacity based on the results of the visual inspection. When the anchor was found to be inadequate as a result of the evaluation, or of slippage greater than 1/16 inch under the tension test, the baseplate was reanalyzed with that bolt missing. The remaining bolts on the baseplate were inspected and tested for adequacy under the higher redistributed load when the reanalysis was acceptable, or for the original design load when the loads could not be redistributed. Inspection and test results showed that 97% of the baseplates were acceptable. All anchor bolts that were inadequate or damaged were replaced to ensure adequacy of the anchorage system.

In order to evaluate operability of each Seismic Category I piping system, the anchor bolt inspection and test results were recorded on a system basis. The system designations shown in Table 15.2-1 were used in conjunction with a QA Category I piping line table to determine systems for Bulletin 79-02 purposes. Of the 14 systems for which anchor bolt inspections were performed, 12 of the systems had acceptance percentages greater than 95%. The acceptance percentages for the other two systems, the reactor coolant system and the residual heat removal system, were 94.7% and 92.1%, respectively. All systems with baseplates inaccessible for bolt inspection and testing had remote visual inspections performed to ensure that all anchor bolts were present and no gross deficiencies existed. For the two systems with less than 95% acceptance, the inaccessible baseplates were further evaluated to ensure high design factors of safety greater than those required by the Bulletin. Review of the baseplates where anchor bolts were found to be inadequate did not indicate any common characteristic (i.e., floor plates, wall plates, or ceiling plates) which would necessitate further inspection and testing of the inaccessible baseplates with a particular characteristic.

Piping systems 2 in. in diameter or less were originally designed by a chart analysis method. To ensure adequacy of the baseplates and anchor bolts in justifying operability of the small-bore piping, a sampling program was initiated. Five 2-inch lines were selected as representative of the small bore piping. Three safety injection lines and two chemical volume and control lines, which have a total of 22 supports with 43 baseplates, were analyzed in this effort. Baseplate analysis efforts show anchor bolt factors of safety ranging from 5.2 to 638, with the majority of anchor bolts having design factors of safety above 60.

Seventy-three anchor bolts on 12 of the small-bore baseplates were inspected and tension tested. Sixty-eight of these anchor bolts (93%) were accepted. The baseplates for the five rejected anchors were reanalyzed with the discrepant bolts missing and all were found acceptable and within the allowable limits. All anchor bolts which were inadequate or damaged were replaced to ensure adequacy of the anchorage system.

The small-bore piping baseplates and anchor bolts were designed and installed by the same architect-engineer and contractor that performed the work on the large-bore piping. Therefore, based on the above results, which are consistent with the large-bore anchor bolt program, a sufficient degree of conservatism exists in the baseplates and anchor bolts of the small-bore piping to justify acceptance of this piping.

All Seismic Category I pipe supports on masonry walls were resupported without attachment to the masonry walls.

IE Bulletin 79-02 inspection details were provided to the NRC by References 18, 19, and 20.

15A.3.5 Piping Systems

The Stone & Webster PSTRESS/SHOCK 2 computer code was used in the seismic analyses of certain systems at Surry Units 1 and 2. This code summed earthquake loadings algebraically, which is unacceptable for reasons set forth by the NRC in IE Bulletin 79-14 (Reference 21) and in a March 13, 1979 Order to Show Cause (Reference 22). As a result, Vepco reanalyzed safety-related systems originally analyzed by SHOCK 2, modified those systems as necessary, depending on the results of the reanalyses, and provided support for the acceptability of the analysis methods used on the remaining Seismic Class I systems.

Portions of the following systems were identified as having been analyzed with SHOCK 2:

- Pressurizer spray and relief.
- Low-head safety injection.
- High-head safety injection.
- Containment and recirculation spray.
- Residual heat removal.
- Component cooling water.
- Service water.
- Main steam.
- High-pressure steam.
- Feedwater.
- Auxiliary feedwater.
- Containment vacuum.
- Fire protection (Unit 1 only).
- Diesel muffler exhaust (Unit 1 only).

Vepco has reanalyzed all pipe stress problems originally analyzed by SHOCK 2. All supports were reanalyzed and modifications completed as necessary.

Reanalysis and safety evaluation details are given in References 23 through 26.

15A.3.5.1 **Reanalysis Methods and Results**

As the original analysis used an algebraic intramodal summation technique, the safety-related piping system supports and attached equipment were reanalyzed with acceptable methods. The reevaluation included a dynamic computer analysis using NUPIPE programs, which incorporated a lumped mass response spectra modal analysis technique.

The floor response spectra used in the reanalysis included the original amplified response spectra specified in this appendix. In some cases, piping was reanalyzed utilizing ARS that were developed using SSI techniques. The peaks in the amplified floor response spectra were broadened by ±15% in accordance with Regulatory Guide 1.122 to account for variation in material properties and approximations in modeling.

The piping systems were modeled as three-dimensional lumped mass systems which included considerations of eccentric masses at valves and appropriate flexibility and stress intensification factors. The dynamic analysis procedures meet the criteria specified in this appendix, and are acceptable. The resultant stresses and loads from the reanalysis were used to evaluate piping, supports, nozzles, and penetrations.

Based on NRC review of the computer codes used for reanalysis, independent check analyses, and a review of modeling methods used by the Licensee, the NRC found the procedures and methods used in reanalyzing these problems acceptable.

The reanalysis included problems involving the reactor coolant system boundary and the supports associated with those problems. Since the reactor coolant system boundary is inside containment and all of the supports have been modified as necessary, there is no potential for a loss-of-coolant accident in the event of a design-basis earthquake.

At the request of the NRC, its consultant, EG&G, performed audit pipe stress calculations of five Surry 1 problems using the NUPIPE computer code. The results of the EG&G audit compared favorably with Vepco’s results.

The piping support designs for affected system piping were inspected by Vepco to verify the location, orientation, support clearances, and support type. Any deviations were incorporated into piping reanalyses. These piping systems were also verified by the NRC Office of Inspection and Enforcement.

The pipe supports were reevaluated in cases where the original support design loading was exceeded as a result of piping reanalysis. In cases where the original support capacity was exceeded, the support reevaluation included the consideration of baseplate flexibility and a verification of actual field construction of the support. Where concrete expansion anchor bolts were used, their capacities, without compromising the originally committed safety margin, were also included in the reevaluation.

The pipe break criteria of this appendix were reviewed in connection with the possible effect of changes of the high-stress point resulting from the reanalyses. Results of the evaluation of the effect the reanalysis has on the pipe break criteria show that no new whip restraints are required. Therefore, the reanalysis has not changed the pipe break protection.

The design and analysis of the supports and attached equipment are in accordance with the criteria specified in this appendix. The piping systems and supports were designed to the allowable limits of ANSI B31.1 for the gross properties, and to the limits of ANSI B31.7 Appendix F, for local stress considerations as per the criteria of this appendix. A reanalysis of the pressurizer surge line to account for the effect of thermal stratification and striping was performed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III 1986 with addenda through 1987 incorporating high cycle fatigue as required by NRC Bulletin 88-11, dated December 20, 1988.

15A.3.5.2 **Verification of Analysis Methods**

The following computer codes and analysis methods have been identified as the current basis for the facility piping design:

1. NUPIPE/S&W
2. NUPIPE
3. Static analysis methods
4. PIPESTRESS

15A.3.5.2.1 NUPIPE/S&W

Stone & Webster has submitted documentation on the NUPIPE/S&W code to the NRC. This code calculates intramodal and intermodal responses according to the provision in Regulatory Guide 1.92 (Reference 27). A review of the code listing by the NRC staff has confirmed this statement. The option used by Vepco specifies an intramodal combination consisting of the addition of the absolute value of the responses due to the vertical earthquake component and the root-mean-square combination of the responses due to the two horizontal earthquake components. Additional documentation has also been submitted by the originators of this code (Quadrex), providing detailed information on the methods of modal combination.

Vepco solved three NRC benchmark piping problems and the solutions showed acceptable agreement with the benchmark solutions. In addition, a confirmatory problem (No. 323A) was provided to Brookhaven National Laboratory for confirmatory solution. A comparison of the solutions demonstrated good agreement (within about 10%).

15A.3.5.2.2 NUPIPE

Ebasco Services, Inc., has submitted documentation to the NRC on the NUPIPE computer code, which was used in the piping reanalysis of Unit 2. This code is considered acceptable for analyses for both units.

This code has previously been reviewed and has been found to satisfy the requirements of Regulatory Guide 1.92. Ebasco solved three of the NRC benchmark piping problems, and its solutions were found to agree closely with the benchmark solutions. They also provided a confirmatory problem (2508A), which was solved by the Brookhaven National Laboratory. Comparison of the solutions showed good agreement.

15A.3.5.2.3 Static Analysis Methods

Static analysis methods, which were used in cases not subjected to computerized seismic analysis, are based on simple beam formulations, wherein seismic stress levels are controlled through use of pre-established seismic spans. These simple beam formulations were utilized to calculate maximum allowable spans based upon an assumed acceleration factor of 1.5 times the peak acceleration obtained from the response spectra. In calculating the maximum span lengths, it was conservatively assumed that a longitudinal pressure stress of 4000 psi and a maximum deadweight stress of 1500 psi were present in the pipe. This combined value of 5500 psi was subtracted from the allowable stress (1.8 S_h for pressure and deadweight and seismic) to obtain a seismic allowable stress.

Calculating maximum spans by this procedure results in maximum allowable spans greater than the deadweight spans recommended in ANSI B31.1. Thus, dead weight governs and provides a greater number of supports resulting in closely spaced restraints. To minimize effects of concentrated weights, restraints were placed as required at valves and other concentrated masses.

For Surry, piping 6 inches in diameter and smaller was generally analyzed using the simplified static method, with the option of utilizing more rigorous methods available to the analyst. Piping 2 inches and below was shown on the piping drawings diagrammatically (i.e., without detailed dimensions). The stress engineers located supports during the installation process working at the site with erection isometric sketches.

The stress analysis was performed by assuming many simple supported straight beams, the spans of which are governed by deadload spacing requirements of ANSI B31.1. The piping fundamental frequencies associated with these maximum allowable spans (9.7 to 13.6 cycles per sec) are not in resonance with the building in which they are located (2 to 8 cycles per sec). The method of equivalent static analysis outlined in this procedure was compared with the NRC's Standard Review Plan 3.7.2 (Reference 28) and found to be acceptable.

15A.3.5.2.4 PIPESTRESS

The Unit 2 RVLIS piping and Head Vent piping were reconfigured to accommodate the head assembly upgrade package. Reanalysis of the piping was performed using PIPESTRESS (Reference 68).

The PIPESTRESS program is a finite element computer program which performs linear elastic analysis of piping systems using the stiffness method of finite element analysis; the displacements of the joints of a given structure are considered basic unknowns. The dynamic analysis by the modal synthesis method utilizes known maximum accelerations produced in a single degree of freedom model of a certain frequency. The principal program assumptions are as follows:

- It is a linearly elastic structure.
- Simultaneous displacement of all supports is described by a single time-dependent function.
- Lumped mass model satisfactorily replaces the continuous structure.
- Modal synthesis is applicable.
- Rotational inertia of the masses has negligible effect.

The results obtained from the pipe stress program PIPESTRESS have been compared with the following:

- ASME Benchmark problem results, Pressure Vessel and Piping 1972 computer programs verification, American Society of Mechanical Engineers.
- Longhand calculations - PIPESTRESS is compatible with NRC Regulatory Guide 1.92. A synthesis of closely spaced modes is provided based on equation 4 of Regulatory Guide 1.92.
- Benchmark confirmatory piping analysis problems were reviewed by the NRC and Brookhaven National Laboratory.

The PIPESTRESS program is used to determine stresses and loads in the piping systems due to restrained thermal expansion, deadweight, seismic inertia and anchor movements, externally applied loads such as jet-loads, and transient forcing functions such as created by fast relief valve opening and closing, fast check valve closure after pipe breaks in main feedwater line, fast valve closure in main steam line, etc. PIPESTRESS analyzes piping systems in accordance with ANSI and ASME codes.

15A.3.5.3 **Soil Structure Interaction**

Soil structure interaction amplified response spectra (SSI-ARS) were used in reanalyzing the piping systems for those cases where the original amplified response spectra did not give satisfactory results. Based upon review of Vepco's information submitted by References 29 and 30, the NRC informed Vepco by Reference 31 and 32 that SSI-ARS was acceptable.

The amplified floor response spectra (ARS) for three levels in the containment, base mat, operating floor and spring line were computed using the multi-layered elastic half-space method and the finite element methods. The results of these analyses were compared for frequency and acceleration of the floor response spectra. The elastic half-space method gave acceleration values that were larger than the finite element method for the operating floor and the spring line. The finite element method gave accelerations slightly higher than the elastic half-space method for the containment base mat. Since no piping systems are located at, and would not use, the base mat spectra for analysis, it was concluded the elastic half-space method would be used for the reevaluation because that would be conservative. The time history used for this comparison was the original design time history used in the original design of the plant, along with the original damping values.

The same floor response spectra were generated for the Regulatory Guide 1.60 (Reference 33) requirements anchored at 0.15g, along with the Regulatory Guide 1.61 (Reference 34) damping values for comparison with the original earthquake input requirements. The time history and the damping values are considered as a consistent set of design parameters. The comparison of the original FSAR design requirements and the Regulatory Guide 1.60 and 1.61 set of values shows that the responses are very consistent, and that the original design requirements are adequate.

The ground-response spectra at the base of the reactor containment structure were calculated and plotted using SHAKE. The response spectra were calculated for three soil profiles, represented by the average low-strain shear modulus, G_{max}, calculated from seismic cross-hole surveys, G_{max} plus 50%, and G_{max} minus 50%. The spectra for each soil profile are plotted on Figures 15A-1, 15A-2, and 15A-3, respectively. Also plotted on these figures is the envelope for 0.5% damping, as presented on Figure 2.5-6.

A study of the effects of the variation of the soil properties was undertaken. The response spectra for the three locations in the containment building were computed for five variations of the soil properties. Variation one considered the computed strain dependent properties using the best estimate of the in-situ properties as input to computer code SHAKE; variation two used the in-situ properties plus 50% as input to the computer code SHAKE; variation three used the in-situ properties minus 50% as input to the computer code SHAKE; variation four considered the first iteration value of the computer code SHAKE using the in-situ properties as input; and variation five used the measured values (low strain) of the soil properties. This study indicated that the response of the structure to the variations in the soil properties is essentially limited to the amplitude of the floor response spectra. It was determined that an increase of the values of the response spectra already used in piping stress calculations by a factor of 1.50 would be acceptable. This increase in the acceleration value for the floor response spectra results in a conservative reanalysis.

To further verify that this increase (1.5) is conservative, the NRC staff conducted an independent study of the variation of soil properties used in the dynamic analyses. First the staff confirmed the adequacy of the average soil properties selected by Vepco and then considered parametric studies of these properties. The results of this effort indicated that a variation of ±25% for the input shear modulus (G_{max}) would accommodate uncertainties in the in-situ soil properties. The results of this variation appear to bound the possible range in soil properties based on staff experience with other site studies. Therefore, Vepco’s studies for ±50% and the increase (1.5 factor) in the response spectra are conservative.

Because the soil shear moduli used in the generation of amplified floor response spectra depend upon the level of strain induced by earthquake motion, the amplified floor response spectra are not in direct proportion to the maximum ground acceleration. Therefore, an investigation of the effects of earthquakes smaller than the design-basis earthquake was also undertaken. For the purpose of this study, amplified floor response spectra were computed for various average strain compatible shear moduli, each due to a peak horizontal ground acceleration ranging from 0.15 to 0.05g. Vepco has provided the resulting family of amplified floor response spectra at the operating floor, which show the design-basis earthquake spectrum to envelope the other spectra due to smaller earthquakes. This demonstrated that the effects of design-basis earthquake are not exceeded by those of smaller earthquakes.

The computer codes used in the reanalysis for the soil structure interaction were:

1. SHAKE
2. PLAXLY
3. REFUND
4. KINACT
5. FRIDAY

The computer code SHAKE is a public domain program and was used to compute only the strain-dependent properties of the supporting soil under the structures. Because this code was only used to compute soil properties, no further verification was necessary.

The computer code PLAXLY is a proprietary code and was qualified by comparison to the existing public domain computer code FLUSH. Amplified response spectra for the containment operating floor computed by both codes were compared.

The computer code REFUND computes the frequency dependent compliance functions for a multi-layered elastic half-space. This code is a proprietary code and was qualified by comparing the results of a sample problem with the results published in the literature.

The computer code KINACT is a proprietary code and is used to compute the translation and rotation time history at the base of the structure from the design time history applied at the free ground surface. This code was qualified by comparing the results of a sample problem to the results of the computer code PLAXLY.

The computer code FRIDAY uses the results of REFUND and KINACT to compute the floor response spectra for each mass point in the mathematical model of the structure. The code is a proprietary program and was qualified by comparing the results of a sample problem with the results of the public domain program STARDYNE.

Additional soil-structure interaction analysis was performed for the Service Building, Safeguards Building, emergency diesel generator rooms, and Containment Spray Pump House to develop in-structure response spectra (ISRS) at certain spectral damping values that were not originally developed for these buildings. A discussion of the methods and criteria used in developing these ISRS was provided to the NRC in Reference 42, as part of the resolution to Generic Letter 87-02 (Reference 39) and Unresolved Safety Issue A-46. These methods and criteria were found adequate and acceptable in the NRC's Safety Evaluation, as indicated in Reference 43. This analysis utilized synthetic time histories as free-field motions. Three synthetic time-histories were developed such that their spectra at 5% damping closely matched the corresponding UFSAR horizontal and vertical ground spectra for Surry, consistent with Figures 2.5-5 and 2.5-6 for OBE and DBE respectively. A very close fit was reached to ensure that no lack of energy occurs at any frequency of interest. The three time histories were statistically independent. Soil and structures were modeled in detail, as discussed below.

The low strain soil properties were obtained from Section 2.4. Industry Standard Code SHAKE was used to perform dynamic analyses of the soil profile to generate the strain compatible soil properties. To account for uncertainties in the soil properties, three low strain soil properties were considered for each seismic input, in accordance with the recommendations in the Standard Review Plan (SRP - NUREG 0800). They are: best estimate, lower bound (shear modulus equal to half the best estimate shear modulus), and upper bound (shear modulus equal to twice the best estimate shear modulus). Thus, three strain compatible soil profiles were developed consistent with soil strains induced by the Housner input.

The structures were modeled as three-dimensional "stick" models with lumped mass and with six degrees of freedom at each node. Eccentricities were explicitly considered at each modeled elevation to account for the effects of torsion and rocking. The damping values were in accordance with Table 15.2-2. For the cases where different portions of the structures were assigned different damping, composite modal damping values were generated based on the strain energy weighted approach.

For each structure, the proper foundation embedment was considered and frequency dependent impedance and scattering functions were calculated for each strain compatible soil case. In addition, the deconvolved time-histories at the foundation levels were verified according to the recommendation of the SRP such that their response spectra (envelop of three soil cases) are not less than sixty percent of the surface spectra. The building models were used together with the proper impedance and scattering functions and for each strain compatible soil case, the three orthogonal time-histories were applied individually. The In Structure Response Spectra (ISRS) in this effort were developed at each elevation for each structure, and peak broadened +15% and -15% to account for uncertainties and variabilities in the structural frequencies, in accordance with Regulatory Guide 1.122.

Additional information on soil-structure interaction can be found in Chapter 2.

15A.4 MOVEMENT OF REACTOR COOLANT SYSTEM COMPONENTS

The criterion for movement of the reactor pressure vessel, under the worst combination of loads, i.e., normal plus the design-basis earthquake plus reactor coolant pipe rupture loads[1], is that the movement of the reactor vessel will not exceed the clearance between a reactor coolant pipe and the surrounding concrete.

The relative motions between reactor coolant system components will be controlled by the structures that are used to support the reactor pressure vessel, steam generators, pressurizer and reactor coolant pumps.

Piping runs that are external to the plant or between buildings and that would affect the health and safety of the public are dynamically stress analyzed. Necessary earthquake stops, constraints, or anchors are judiciously located to withstand motion, but allow for thermal movement.

The dynamic seismic stresses are calculated using the appropriate operational-basis earthquake and design-basis earthquake response spectrum. The design criteria for the analysis of Class I piping systems are in accordance with the code requirements of ANSI B31.1. Pressure, deadload, thermal, and seismic pipe stresses are combined in accordance with the code.

The structures to which the piping is attached are also designed to withstand these loads. Included in the pipe stress analysis are horizontal and vertical differential motion caused by rotation, translation, and flexure of the respective structures assumed to be out of phase with each other, plus the relative motion from earthquake orbital displacement of the founding soil.

1. As discussed in Section 15.6.2, it is no longer necessary to consider the dynamic effects of a postulated rupture of the primary reactor coolant loop piping. However, pipe ruptures of reactor coolant branch lines, the main steam lines are still postulated.

In most cases, piping runs are stress-analyzed by system, thus determining the effect of branch lines joining the main run or other piping.

In the analysis of piping running between structures, and to different elevations within the same structure, consideration has been given to differential motion of the piping supports and anchors.

The building displacements caused by an earthquake, which include rocking and translation of the structures, as well as the relative motion from orbital displacement of the foundation soil, are evaluated at the elevation or elevations at which the piping is supported. These displacements are then applied to the supports and anchors as external movements to the piping system, and stresses are calculated.

For the analysis of piping supported by different structures, an out-of-phase condition is always assumed, and the direction of the displacements applied to the piping supports and anchors are chosen to reflect the out-of-phase condition to yield the most conservative results.

15A.5 TESTS TO DEMONSTRATE THE CONSERVATISM OF THE LIMIT CURVES

Tests performed at Westinghouse Material Testing Laboratory in Pittsburgh demonstrate the conservatism of the limit curves presented in WCAP-5890, Revision 1 (Reference 35). Carbon steel and stainless steel pipes have been tested under various combinations of axial and transverse loads to determine failure loads. Specimens about 1.5 foot long have been cut from 1.5-inch nominal diameter Schedule 160 pipes. The materials employed were SA 106B carbon steel and Type 304 stainless steel. These specimens were kept internally pressurized to 3000 psia for the entire duration of the tests. Tables 15A-3 and 15A-4 summarize the tests that have undergone evaluation and the results of this evaluation.

Standard ASTM tensile specimens have been modeled from pieces of the test pipes and stress-strain curves determined. These curves have been conservatively approximated with trapezoidal stress-strain curves as indicated in WCAP-5890, Revision 1. The limit curves for both SA 106B carbon steel and Type 304 stainless steel for the test conditions have been calculated and are reported in Figures 15A-4 and 15A-5, respectively. The experimental points, i.e., stress intensities versus axial stress as listed in Tables 15A-3 and 15A-4 are shown in Figures 15A-4 and 15A-5. Also shown in these figures are the limit curves as calculated by the use of the trapezoidal stress-strain curves up to the ultimate stress. Comparisons between the experimental points and the design limit curves show the conservatism of the latter.

15A.5.1 Westinghouse Topical Reports

WCAP-5890, Rev. 1, has been replaced by WCAP-7287 (Reference 36). The revisions affected limits for the combination of normal loads plus design-basis earthquake loads plus pipe rupture loads associated with a loss-of-coolant accident. The changes reflected agreement with the staff of the Atomic Energy Commission (AEC) Division of Reactor Licensing on the stress limits for the above-mentioned load combinations. Details of the manner in which the revisions were developed are as follows:

1. Material data used to develop stress-strain curves.

   Typical stress-strain curves of type 304 stainless steel (Figure 15A-6), Inconel 600 (Figure 15A-7) and SA 302B low alloy steel (Figure 15A-8) at 600°F were generated from tests using graphs of applied load versus cross-head displacement as automatically plotted by the recorder of the tensile test apparatus. The scale and sensitivity of the test apparatus recorder ensured accurate measurement of the uniform strain.

   For materials other than these three, stress-strain curves were developed by conservative use of pertinent available material data (i.e., lowest values of uniform strain and initial strain hardening). Where the available data were not sufficient to develop a reliable stress-strain curve, three standard ASTM tensile tests of the material in question were performed at design temperature. These data were conservatively applied in developing a stress-strain curve as described above.

2. The ordinate (stress) of the stress-strain curves was normalized to the measured yield strength.

3. Twenty percent of uniform strain as defined on the curve developed under Item 1 was used as the allowed membrane strain.

4. The normalized stress ratio was established at 20% of uniform strain on the normalized stress-strain curves developed under item 2.

5. The value of the membrane stress limit was established.

6. The normalized stress ratio in item 4 was multiplied by the applicable code yield strength at the design temperature to get the membrane stress limit. The actual physical properties as determined from standard ASTM tensile tests on specimens from the same heats was allowed as an alternate method of determining the membrane stress limit. Sufficient documentation was provided to support the actual material properties used.

7. Limit curves for the combination of local membrane and bending stresses were developed.

   The limit curves were developed by using the analytical approach presented in WCAP-5890, Revision 1, and the stress-strain curve up to the membrane stress limit as developed under item 5. These limit curves were within the limit curves discussed with the staff of the AEC Division of Reactor Licensing during meetings on November 30 and December 1, 1967, for the same materials.

15A.5.2 Framatome Computer Programs (Unit 1 only)

This section describes computer programs that were used by Framatome ANP for the dynamic and static analysis of Class 1 equipment and components during the process of qualifying the Unit 1 replacement reactor vessel closure head to ASME Section III requirements. These computer programs meet the requirements of the Dominion and Framatome ANP software validation programs. The validation program meets the requirements of 10 CFR 50 Appendix B, ASME NQA 1, and ANSI N45.2. The software validation compliance was verified during an onsite quality audit of the replacement closure head vendor. Audit results and objective evidence of the software validation are available in the Framatome ANP audit file. These programs provide results that are essentially the same or more conservative than the analyses of record.

15A.5.2.1 **BWSPAN**

BWSPAN (Reference 63) is designed to perform analysis in accordance with the ASME Boiler and Pressure Vessel Code, Section III Nuclear Power Plant Components and the ANSI B31.1 Power Piping Code. This code has been specifically used for evaluating the configuration of the RVLIS piping routed from the closure head up to and including “RX Vessel Vent Line to RVLIS Isolation Valve,” 1-RC-603, “Rx Vessel Vent Line to RVLIS Isolation Vent Valve,” 1-RC-36 (including associated drain valve 1-RC-186) and to a location in the run of the pipe just upstream of valve 1-RC-185.

15A.5.2.2 **BIJLAARD**

BIJLAARD (Reference 64) is designed to calculate local stresses in a cylindrical or spherical shell induced by a nozzle or support.

15A.5.2.3 **FERMETURE**

FERMETURE (Reference 65) is designed to calculate the loadings used for the closure analysis. FERMETURE calculates the stud load components for a given set of temperature and pressure values. Additionally, FERMETURE verifies the leak tightness of the vessel closure.

15A.5.2.4 **SYSTUS**

SYSTUS (Reference 66) is designed to analyze the thermal-mechanical behavior of beams and solid structures in two or three dimensions.

15A.5.2.5 **RCCM-ASME**

RCCM-ASME Program (Reference 67) is a special postprocessor of SYSTUS that allows manipulation of SYSTUS results for stress analyses in accordance with the rules defined by the ASME Code Section III including stresses linearization, usage factor calculation and thermal ratchet analysis.

15A.6 REACTOR COOLANT LOOP (RCL) PIPING REANALYSIS SUBSEQUENT TO LEAK BEFORE BREAK AND SNUBBER ELIMINATION

Table 15A-5 identifies the maximum level of stress as a percentage of the Code allowable stress for the analysis that was performed for implementation of Leak Before Break (LBB), which allowed for the removal of large snubbers connected to the primary loop piping. Reanalysis of the Reactor Coolant Loop piping and supports was performed subsequent to the implementation of LBB to support implementation of several plant changes and refinement of analytical modeling, which include:

- Measurement Uncertainty Recapture (MUR) power uprate
- Implementation of the 15 x 15 Upgrade Fuel Design
- Nuclear Safety Advisory Letter NSAL-11-2 (Reference 71) concerning the assumed stiffness of the Reactor Vessel Lower Radial Keys.

The resultant updated stresses as a percentage of the Code allowable stress and factors of safety for supports are shown in Table 15A-8 and Table 15A-9 respectively.

In the stress reanalyses performed by Westinghouse, and documented in References 69 and 70, two additional RCL branch line pipe break cases, consisting of RHR Suction and Accumulator Injection line breaks, were added, which were not analyzed previously. Addition of these postulated breaks increased the faulted stresses. However, the recalculated stresses still remain below the code allowable stress of 2.4 S_h. The recalculated stresses for analyzed loading conditions are shown in Table 15A-8. The change only affects the faulted condition evaluation. All the other stresses (Pressure, Deadweight, Thermal, Seismic OBE and DBE) are unchanged. The recalculated margins for pipe supports based upon Shaw calculation 13019801-P-0001 (Reference 71) are shown in Table 15A-9. The stated change affects only the faulted loads due to the two additional pipe break cases analyzed. There is no change in other loads, including seismic OBE and DBE loads.

As noted in Section 15.6.2 and its associated references, the application of Leak-Before-Break was subsequently extended to the Surry Units 1 and 2 Reactor Coolant System branch piping including: the Pressurizer Surge, Residual Heat Removal, Accumulator, Loop Bypass, and Safety Injection piping up to each line’s first pressure isolation valve. The evaluation demonstrated the dynamic effects of the pipe rupture resulting from postulated breaks in the Surge, RHR, Accumulator, Loop Bypass and SI line piping need not be considered in the structural design basis of Surry Units 1 and 2 for the 80 year period of extended plant operations.

15A REFERENCES

1. R. A. Wiesemann, R. E. Tome, and R. Salvatore, *Ultimate Strength Criteria to Ensure No Loss of Function of Piping and Vessels under Earthquake Loadings*, WCAP-5890, Revision 1.

2. TID-7024, Chapter 6.

3. *Seismic Testing of Electrical and Control System Equipment*, WCAP-7397-L.

4. NRC Generic Letter 84-04, *Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops*, dated February 1, 1984.

5. NRC Generic Letter 87-11, *Relaxation In Arbitrary Intermediate Pipe Rupture Requirements,* dated June 19, 1987.

6. Westinghouse Topical Report WCAP 9558, Revision 2, *Mechanistic Fracture Evaluation of Reactor Coolant Pipe Containing a Postulated Circumferential Throughwall Crack*, May 1981.

7. Westinghouse Topical Report WCAP 9787, *Tensile and Toughness Properties of Primary Piping Weld Metal for Use in Mechanistic Fracture Evaluation*, in May 1981.

8. Letter from Vepco to NRC, Subject: *Request for Partial Exemption from General Design Criterion 4,* dated November 5, 1985 (Serial No. 85136).

9. Letter from Vepco to NRC, Subject: *Request for Partial Exemption from General Design Criterion 4 - Supplement,* dated December 3, 1985 (Serial No. 85-136A).

10. Letter from Vepco to NRC, Subject: *Partial Exemption from General Design Criterion 4 - Request for Additional Information,* dated December 27, 1985 (Serial No. 85-136B).

11. Letter from Vepco to NRC, Subject: *Partial Exemption from General Design Criterion 4 - Request for Additional Information,* dated January 14, 1986 (Serial No. 85-136C).

12. *Amendment to General Design Criterion 4 (GDC-4), 10 CFR Part 50, Appendix A,* published in Federal Register 51 FR 12502, effective May 12, 1986.

13. Letter from Vepco to NRC, Subject: *Proposed License Amendment - GDC 4,* dated April 30, 1986 (Serial No. 86-245).

14. Letter from NRC to Vepco transmitting Surry Unit 1 and 2 License Amendments No. 108 and related safety evaluations, dated June 16, 1986.

15. Letter from Vepco to NRC, Subject: Generic Letter 87-11, dated September 12, 1988 (Serial No. 88-371).

16. U.S. Nuclear Regulatory Commission, *Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts*, IE Bulletin 79-02, March 8, 1979 (Revision 1), August 20, 1979 (Revision 2).

17. Teledyne Engineering Services, *Summary Report. Generic Response to USNRC I&E Bulletin No. 79-02*, Base Plate/Concrete Expansion Anchor Bolts, Technical Report TR-3501-1, Revision 1.

18. Letter from Vepco to NRC, Subject: IE Bulletin 79-02, dated December 7, 1979.

19. Letter from W. C. Spencer, Vepco to J. P. O'Reilly, NRC, Subject: *Supplemental Response to IE Bulletin 79-02, Revision 2, Surry Power Station Units 1 and 2,* dated January 30, 1980.

20. Letter from W. C. Spencer, Vepco, to J. P. O'Reilly, NRC, Subject: *Final Report on IE Bulletin 79-02, Revision 2, Surry Power Station Unit 2,* dated August 4, 1980.

21. U.S. Nuclear Regulatory Commission, *Seismic Analyses for As-Built Safety-Related Piping Systems,* IE Bulletin 79-14, July 2, 1979.

22. Letter from H. R. Denton, NRC, to W. L. Proffit, Vepco, Subject: *Show Cause Orders for Surry Power Station, Units 1 and 2,* dated March 13, 1979.

23. Letter from W. C. Spencer, Vepco, to H. R. Denton, NRC, transmitting *Report on the Reanalysis of Safety-Related Piping Systems, Surry Power Station Unit 1*, dated June 5, 1979.

24. Letter from H. R. Denton, NRC, to W. L. Proffit, Vepco, Subject: *Order Lifting the Suspension of Facility Operation Required by the Order to Show Cause Dated March 13, 1979, for the Surry Power Station, Unit 1,* dated August 22, 1979.

25. Letter from W. C. Spencer, Vepco, to H. R. Denton, NRC, transmitting *Report on the Reanalysis of Safety-Related Piping Systems, Surry Power Station Unit 2,* dated February 22, 1980.

26. Letter from H. R. Denton, NRC, to W. L. Proffit, Vepco, Subject: *Order Lifting the Suspension of Facility Operation Required by the Order to Show Cause Dated March 13, 1979, for the Surry Power Station,* Unit 2, March 26, 1980.

27. U.S. Nuclear Regulatory Commission, *Combining Modul Responses and Spatial Components in Seismic Response Analysis,* Regulatory Guide 1.92, February 1976.

28. *Seismic System Analysis*, Standard Review Plan 3.7.2, November 24, 1975.

29. Letter from W. C. Spencer, Vepco, to V. Stello, NRC, Subject: *Response to NRC Information Request on Soil-Structure Interaction,* dated May 2, 1979.

30. Letter from W. C. Spencer, Vepco, to D. G. Eisenhut, NRC, Subject: *Operating-Basis Earthquake Reanalysis of Piping Systems, Surry Power Station Units 1 and 2,* dated September 13, 1979.

31. Letter from NRC to Vepco, Subject: *Soil-Structure Interaction Position,* dated March 25, 1979.

32. Letter from D. G. Eisenhut, NRC, to W. L. Proffit, Vepco, Subject: *Soil-Structure Interaction Conclusions for Surry Power Station Units 1 and 2,* dated November 15, 1979.

33. U.S. Nuclear Regulatory Commission, *Design Response Spectra for Seismic Design of Nuclear Power Plants*, Regulatory Guide 1.60, December 1973.

34. U.S. Nuclear Regulatory Commission, *Damping Values for Seismic Design of Nuclear Power Plants*, Regulatory Guide 1.61, October 1973.

35. WCAP-5890, Revision 1.

36. WCAP-7287.

37. U.S. NRC Bulletin No. 88-11: *Pressurizer Surge Line Thermal Stratification,* USNRC, December 20, 1988.

38. Virginia Power Letters Serial Nos. 89-006A dated May 3, 1989 and 89-006B dated November 13, 1989 to United States Nuclear Regulatory Commission.

39. NRC Generic Letter 87-02, *Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46,* February 19, 1987.

40. *Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment, Revision 3, Updated 05/16/97,* prepared by Seismic Qualification Utility Group (SQUG) and sent to the NRC by letter dated May 16, 1997.

41. Letter from NRC to Vepco, Subject: *Computer Program for Pipe Stress Analysis of ASME Class 2 and 3 Piping,* dated June 16, 1993. (Serial No. 93-395)

42. Letter from W. L. Stewart, Virginia Power, to U.S. Nuclear Regulatory Commission, September 18, 1992, *Virginia Electric and Power Company, Surry Power Station Units 1 and 2, North Anna Power Station Units 1 and 2, Response to Supplement 1 of Generic Letter 87-02 SQUG Resolution of Unresolved Safety Issue A-46,* Serial Number 92-384.

43. NRC letter to Virginia Power, Serial No. 92-763, *Safety Evaluation of NAPS Units 1 and 2 and SPS Units 1 and 2, 120 day response to Supplement No. 1 to Generic Letter 87-02,* November 20, 1992.

44. *Supplemental Safety Evaluation Report No. 2 (SSER No. 2) on Seismic Qualification Utilities Group's Generic Implementation Procedure, Revision 2, Corrected February 14, 1992, for Implementation of GL 87-02 (USI A-46), Verification of Seismic Adequacy of Equipment in Older Operating Nuclear Plants,* U.S. Nuclear Regulatory Commission, May 22, 1992.

45. *Supplemental Safety Evaluation Report No. 3 (SSER No. 3) on the Review of Revision 3 to the Generic Implementation Procedure for Seismic Verification of Nuclear Power Plant Equipment, Updated May 16, 1997,* U.S. Nuclear Regulatory Commission, December 4, 1997.

46. Virginia Power Letter to Document Control Desk (NRC), *Surry Power Station, Units 1 and 2, Summary Report for Resolution of Unresolved Safety Issue (USI) A-46,* November 26, 1997.

47. NRC letter to Virginia Power, *Surry Power Station, Units 1 and 2 - Request for Additional Information Regarding Seismic Qualification of Mechanical and Electrical Equipment (GL 87-02),* February 23, 1998.

48. Virginia Power letter to NRC, *Surry Power Station, Units 1 and 2 - Response to Request dated February 23, 1998 for Additional Information on USI A-46 Summary Report (GL 87-02),* April 22, 1998.

49. NRC letter to Virginia Power, *Surry Power Station, Units 1 and 2 - Request for Additional Information Regarding Seismic Qualification of Mechanical and Electrical Equipment (GL 87-02),* September 11, 1998.

50. Virginia Power letter to NRC, *Surry Power Station, Units 1 and 2 - GL 87-02 - Response to Request for Additional Information dated September 11, 1998 on USI A-46 Summary Report,* January 5, 1999.

51. Virginia Power Letter to Document Control Desk (NRC), *Surry Power Station, Units 1 and 2, Completion of Outlier Resolution - USI A-46 Program, GL 87-02 - Verification of Seismic Adequacy of Mechanical and Electrical Equipment,* February 4, 2000.

52. NRC Letter to Virginia Power, Serial Number 00-398, transmitting Safety Evaluation by the Office of Nuclear Reactor Regulation Evaluation of Virginia Electric and Power Company Response to Supplement No. 1 to Generic Letter 87-02, Surry Units 1 and 2, July 25, 2000.

53. NRC (Brian Sheron) letter to SQUG (Neil Smith), *Clarification of the Staff's Position Regarding Incorporation of the GIP Method as a Revision to the Plant Licensing Basis,* June 19, 1998.

54. NRC letter to SQUG, *Review of Seismic Qualification Utility Group's Report on the Use of the Generic Implementation Procedure for New and Replacement Equipment and Parts,* June 23, 1999.

55. *Implementation Guidelines for Seismic Qualification of New and Replacement Equipment/Parts (NARE) Using the Generic Implementation Procedure (GIP), Revision 4,* Prepared for EPRI and SQUG by MPR Associates, July 2000.

56. *Guideline for the Seismic Technical Evaluation of Replacement Items (STERI) for Nuclear Power Plants*, EPRI Report NP-7484, February 1993.

57. *Generic Seismic Technical Evaluations of Replacement Items (GSTERI) for Nuclear Power Plants*, EPRI Report TR-104871, May 1995.

58. *Generic Seismic Technical Evaluations of Replacement Items for Nuclear Power Plants - Item Specific Evaluations, including Supplement 1,* EPRI Report SU-105849, September 1997.

59. *Critical Characteristics for Acceptance of Seismically Sensitive Items (CCASSI),* EPRI Report TR-112579, September 2000.

60. EPRI NP-6041-SL, Revision 1, *A Methodology for Assessment of Nuclear Plant Seismic Margin",* August 1991.

61. BNL 52361, *Seismic Design and Evaluation Guidelines for the Department of Energy High Level Waste Storage Tanks and Appurtenances,* Brookhaven National Laboratory, Upton, New York, October 1995.

62. Dominion General Engineering Nuclear Standard STD-GN-0038, *Seismic Qualification of Equipment*.

63. *BWSPAN - Pipe Stress Analysis,* Version 10.2 (2A-4 Rev. T), Users Manual, Developed by Framatome ANP.

64. *BIJLAARD - Local Shell Stress Calculation,* Version 1.0, Developed by Framatome ANP.

65. *FERMETURE - Closure Analysis,* Version AXP 2.2, Developed by Framatome ANP.

66. *SYSTUS - General Finite Element System,* Developed by Framatome ANP Module SYSNUKE Version 233 AXP 3 for Closure Head Stress and Fatigue Analysis Module NUKE Version 1.03 SGI for Adapter Tube and Vent Pipe Stress and Fatigue Analysis.

67. *RCCM-ASME - Pressure Retaining Boundary Analysis,* according to ASME Code Developed by Framatome ANP, Version AXP 2.3.12 for Closure Head Stress and Fatigue Analysis Version 2.3.13 SGI and 2.3.14 SGI for Adapter Tube and Vent Pipe Stress and Fatigue Analysis.

68. *PIPESTRESS Computer Software,* DST Computer Services S.A.

69. *Surry 1 and 2 RCL Piping Stress Analysis and Surge Stratification Analysis for RTSR*, Westinghouse Calculation No. CN-PAFM-10-36, Rev. 1, January 2013.

70. *Factor of Safety for Primary Components and Supports with Reduced Snubber Configuration, Calculations No. 14937.24-NMB-333-GA, Rev. 0, Addendum 00B, August 2013*

71. *Impact of Change in Lower Radial Key Stiffness Value, Westinghouse Nuclear Safety Advisory Letter NSAL-11-2, June 2011.*

Table 15A-1
LOADING CONDITIONS AND STRESS LIMITS

Pressure Vessels

Loading Conditions	Stress Limits	
1. Normal conditions	a. $P_m \leq S_m$	
	b. P_m(or P_L)+$P_B \leq 1.5S_m$	(Note 1)
	c. P_m(or P_L)+P_B+$Q \leq 3.0S_m$	(Note 2)
2. Upset conditions	a. $P_m \leq S_m$	
	b. P_m (or P_L)+$P_B \leq 1.5S_m$	(Note 1)
	c. P_m(or P_L)+P_B+$Q \leq 3.0S_m$	(Note 2)
3. Emergency conditions	a. $P_m \leq 1.2S_m$, or $P_m \leq S_y$, whichever is larger	
	b. P_m (or P_L)+$P_B \leq 1.5(1.2S_m)$, or P_m (or P_L)+$P_B \leq 1.5$ (S_y) whichever is larger	(Note 3) (Note 3)
4. Faulted conditions	Design limit curves of WCAP-5890, Rev. 1, as modified by Section 15A.5.1	(Note 4)

where:

P_m = primary general membrane stress intensity
P_L = primary local membrane stress intensity
P_B = primary bending stress intensity
Q = secondary stress intensity
S_m = stress intensity value from ASME B&PV Code, Section III, Nuclear Vessels
S_y = minimum specified material yield

Pressure Piping (Note 6)

Loading Conditions	Stress Limits	
1. Normal conditions	$P_m \leq S$	
2. Upset conditions	$P_m \leq 1.2S$	
3. Emergency conditions	$P_m \leq 1.8S$	
4. Faulted conditions	Design limit curves of WCAP-5890, Revision 1, as modified by Section 15A.5.1	(Note 4)

where

P_m = principal stress
S = Allowable stress from USAS B31.1, Code for Power Piping

7	Equipment Supports
1. Normal conditions	Within working limits
2. Upset conditions	Within working limits

Table 15A-1 (CONTINUED)
LOADING CONDITIONS AND STRESS LIMITS

	Equipment Supports (continued)	
3. Emergency conditions	Within material yield strength after load redistribution	(Note 5)
4. Faulted conditions	Within material yield strength after load redistribution	(Note 5)

Note 1: The limits on local membrane stress intensity ($P_L \leq 1.5Sm$) and primary membrane plus primary bending stress intensity (P_M (or P_L) + $P_B \leq 1.5S_m$) need not be satisfied at a specific location if it can be shown by means of limit analysis or by tests that the specified loadings do not exceed 2/3 of the lower bound collapse load as per paragraph N-417.6(b) of the ASME B&PV Code, Section III, Nuclear Vessels.

Note 2: In lieu of satisfying the specific requirements for the local membrane ($P_L \leq 1.5Sm$) or the primary plus secondary stress intensity ($P_L + P_B + Q \leq 3S_m$) at a specific location, the structural action may be calculated on a plastic basis and the design will be considered to be acceptable if shakedown occurs, as opposed to continuing deformation, and if the deformation which occur prior to shakedown do not exceed specified limits, as per paragraph N-417.6(a)(2) of the ASME B&PV Code, Section III, Nuclear Vessels.

Note 3: The limits on local membrane stress intensity ($P_L \leq 1.5S_m$) and primary membrane plus primary bending stress intensity (P_m (or P_L) + $P_B \leq 1.5S_m$) need not be satisfied at a specific location if it can be shown by means of limit analysis or by test that the specified loadings do not exceed 120% of 2/3 of the lower bound collapse load as per paragraph N-417.10(c) of the ASME B&PV Code, Section III, Nuclear Vessels.

Note 4: As an alternate to the design limit curves that represent a pseudo plastic instability analysis, a plastic instability analysis may be performed in some specific cases considering the actual strainhardening characteristics of the material, but with the yield strength adjusted to correspond to the tabulated value at the appropriate temperature in Table N-424 or N-425, as per paragraph N-417.11c of the ASME B&PV Code, Section III, Nuclear Vessels. These specific cases will be justified on an individual basis.

Note 5: Higher stress values can be adopted if a valid limit or plastic instability analysis of the support and supported component/system is performed.

Note 6: As required by NRC Bulletin 88-11, pressurizer surge line is re-evaluated in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, 1986 with addenda through 1987 incorporating high cycle fatigue.

Table 15A-2
MINIMUM MARGINS OF SAFETY

	Loading Conditions		
Material	Upset Conditions	Emergency Conditions	Faulted Conditions (Note 1)
SA302 Grade B	200%	150%	27%
Inconel 600	228%	172%	43%
316 SST	222%	169%	60%
A212 Grade B	346%	272%	55%

Note: Based upon the limit curves computed using Section 15A.5.1.

Table 15A-3

TESTS AND TEST RESULTS ON SA 106B CARBON STEEL PIPE SPECIMENS

(INTERNAL PRESSURIZATION = 3000 PSIA)

	Pseudo-elastic Axial Stress Normalized to the Yield Stress	Pseudo-elastic Bending Stress Normalized to the Yield Stress	Pseudo-elastic Stress Intensity Normalized to the Yield Stress	Strain Percent (gauge length)
Pure tension (no weld)	1.736	0.0	1.770	22.61% (12 in.)
	1.840	0.0	1.847	22.32% (12 in.)
Pure bending [a]	0.10	>2.348	2.382	>35.4X (1 in.)
Tension + bending (no weld)	>1.375	>1.030	2.440	>7.75% (6 in.)
	>1.585	>0.565	2.180	--
	>1.845	>0.266	2.145	--
Compression + bending (no weld)	>1.130	1.08	2.410	--
Pure tension (circumf. weld)	1.852	0.0	1.886	20.05% (12 in.)
Pure bending (circumf. weld)	0.10	>2.580	2.614	>30.19X (1.5 in.)
Pure bending [b] (rejected circumf. weld)	0.10	2.460	2.494	14.51% (2 in.)

a. The limit capability of the test apparatus has been reached before failure of these specimens was approached.

b. This test was performed on a welded pipe specimen that has been rejected by the inspector prior to the test for gross lack of penetration in weld. This was the only test in which the weld failed. The specimen exhibited substantial ductility prior to failure.

Table 15A-4
TESTS AND TEST RESULTS ON 304 STAINLESS STEEL SPECIMENS
(INTERNAL PRESSURIZATION = 3000 PSIA)

	Pseudo-elastic Axial Stress Normalized to the Yield Stress	Pseudo-elastic Bending Stress Normalized to the Yield Stress	Pseudo-elastic Stress Intensity Normalized to the Yield Stress	Strain Percent (gauge length)
Pure tension (no weld)	2.495	0.0	2.53	52. 12 (12 in.)
Pure bending [a]	+0.10	>2.91	>2.945	>30.0% (1 in.)
Tension + bending (no weld)	>+2.09	>0.42	>2.55	--
Pure bending (circumf. weld)	+0.10	>3 27	>3.30	>25.0% (1.5 in.)
Pure tension (circumf. weld)	+2.46	0.0	2.49	44.6% (12 in.)

a. The limit capability of the test apparatus has been reached before failure of these specimens was approached.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 15A-5

LEVEL OF STRESS AS A PERCENTAGE OF CODE ALLOWABLE STRESS

Loading	Hot Leg	Crossover Leg	Cold Leg	Code Allowable Stress
Thermal	38.6%	15.6%	7.4%	S_A
Pressure + Deadweight	68.0%	48.7%	53.3%	$1.0S_h$[a]
Pressure + Deadweight + OBE	65.5%	65.0%	60.0%	$1.2S_h$[a]
Pressure + Deadweight + DBE	49.6%	51.1%	48.9%	$1.8S_h$[a]

In addition, the pipe Stresses in the primary reactor coolant loop piping under combined accident loadings from pressure, deadweight, plus SRSS of design-basis earthquake and controlling pipe ruptures are less than $1.8S_h$, which is conservative both respect to the allowables per Section 15A.5 and to $2.4S_h$ which is permitted by the current ASME Code.

a. S_h =15 Ksi

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 15A-6

FACTORS OF SAFETY FOR COMPONENT SUPPORTS UNDER DESIGN-BASIS SEISMIC AND NORMAL OPERATING LOADS SURRY UNITS 1 AND 2

Component	Factor of Safety[a]		
	Original Design[b]	Modified Design[c]	Final Design[d]
Steam Generator Shell	>20.0	>20.0	>20.0
Steam Generator Upper Support			
Component	19.2	15.9	13.7
Upper Guide	7.3	4.6	3.3
Snubber	14.2	14.2	6.3
Steam Generator Lower Support			
Hanger Rod	1.8	1.8	1.8
Swivel End Coupling	16.3	13.4	12.2
Steam Generator Foot			
Vertical Force	2.7	2.8	2.8
Tangential Force	16.0	12.4	12.4
Reactor Coolant Pump Foot			
Vertical Force	5.5	5.2	5.3
Tangential Force	15.4	15.8	15.9
Radial Force	15.4	15.0	12.8
Reactor Coolant Pump Support			
Upper Vertical	5.5	5.0	5.0
Upper Horizontal	5.0	5.0	5.0
Lower Vertical	3.6	3.6	3.6
Lower Diagonal	4.6	4.6	4.6

a. Factor of Safety - (Allowable Load)/(TotaL Load of Deadweight, Pressure, Thermal and DBE)

b. Original design incorporated ten large-bore snubber per loop for primary reactor coolant system pipe rupture loads.

c. Modified design implemented elimination of six large-bore snubbers based on “leak-before-break”; n the four remaining large-bore snubbers were required to carry loads of main steam line rupture.

d. Final design incorporates only two large-bore snubbers on Steam Generator, following elimination of lateral loads due to postulated AIB of Main Steam Line.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 15A-7

FACTORS OF SAFETY FOR COMPONENT SUPPORTS UNDER COMBINED ACCIDENT LOADS SURRY UNITS 1 AND 2

Component	Factor of Safety[a]		
	Original Design[c]	Modified Design[d]	Final Design[e]
Steam Generator Shell	2.5	2.4	8.3
Steam Generator Upper Support			
Component	2.8	2.8	7.5
Upper Guide	1.1	1.1	2.6
Snubber	1.3	1.4	1.9
Steam Generator Lower Support			
Hanger Rod	1.7	1.7	1.7
Swivel End Coupling	2.3	2.3	2.3
Steam Generator Foot[b]			
Vertical Force	4.0	4.2	4.3
Tangential Force	7.4	7.2	7.3
Reactor Coolant Pump Foot[b]			
Vertical Force	11.9	11.3	10.9
Tangential Force	>20.0	>20.0	>20.0
Radial Force	>20.0	>20.0	>20.0
Reactor Coolant Pump Support			
Upper Vertical	4.5	4.3	4.2
Upper Horizontal	5.3	4.8	4.6
Lower Vertical	3.8	3.5	3.5
Lower Diagonal	3.0	3.0	3.0

a. Factor of Safety - (Allowable Load)/[TotaL Load of Deadweight, Pressure, Thermal and SRSS (DBE+Pipe Rupture)].

b. Allowable loads from Westinghouse specification are higher for pipe rupture case; this results in higher normal factors of safety for some components for this case compared with factors of safety for design basis seismic loads only (Table 15A-4).

c. Original design incorporated ten large-bore snubber per loop for primary reactor coolant system pipe rupture loads.

d. Modified design implemented elimination of six large-bore snubbers based on “leak-before-break”; n the four remaining large-bore snubbers were required to carry loads of main steam line rupture.

e. Final design incorporates only two large-bore snubbers on Steam Generator, following elimination of lateral loads due to postulated AIB of Main Steam Line.

Table 15A-8
CALCULATED STRESS AS PERCENTAGE OF CODE ALLOWABLE STRESS
(REFERENCE 69)

Loading	Hot Leg	Crossover Leg	Cold Leg	Code Allowable Stress
Thermal	38.6% (unchanged)	15.6% (unchanged)	7.4% (unchanged)	S_A
Pressure + Deadweight	68.0% (unchanged)	48.7% (unchanged)	53.3% (unchanged)	1.1 S_h[a]
Pressure + Deadweight + OBE	65.5% (unchanged)	65.0% (unchanged)	60.0% (unchanged)	1.2 S_h[a]
Pressure + Deadweight + DBE	49.6% (unchanged)	51.1% (unchanged)	48.9% (unchanged)	1.8 S_h[a]
Pressure + Deadweight + $\{(DBE)^2 + (LOCA/Pipe Rupture)^2\}^{1/2}$	50.8%	53.9%	98.1%	2.4 S_h[b, c]

a. S_h = 15 ksi

b. The faulted case maximum calculated stress which includes maximum stress for worst case LOCA/pipe break is compared against ASME code allowable stress of 2.4 S_h. This is acceptable under current industry practice and widely used by Westinghouse in the reanalysis of RCL piping for their plants. Based upon the material test data performed by Westinghouse, documented in WCAP-5890, Rev. 1 which was later replaced by WCAP-7287 and shown summarily in Tables 15A-3 plus 15A-4 and Figures 15A-4 plus 15A-5, the design limit curves are conservative compared to test results shown.

c. RCL LOCA analysis has been revised and upgraded to incorporate ELBB (Extended Leak Before Break) technology resulting in significant reduction in pipe support loads and pipe stresses. As a result, LOCA loads and stress values shown in the above table will be significantly reduced once these tables are revised.

Table 15A-9
FACTORS OF SAFETY FOR STEAM GENERATOR AND REACTOR COOLANT PUMP SUPPORTS (REFERENCE 70)

Component	**Factor of Safety**
Steam Generator Upper Support:	
Component	7.5
Upper Guide	2.5
Snubber	1.5
Steam Generator Lower Support:	
Hanger Rod	1.2
Swivel End Coupling	1.7
Reactor Coolant Pump Support:	
Upper Vertical	3.1
Upper Horizontal	3.4
Lower Vertical	2.6
Lower Diagonal	2.2

a. RCL LOCA analysis has been revised and upgraded to incorporate ELBB (Extended Leak Before Break) technology resulting in significant reduction in pipe support loads and pipe stresses. As a result, LOCA loads shown in the above table will be significantly reduced once this table is revised.

Figure 15A-1
ENVELOPE FOR 0.5% DAMPING GROUND RESPONSE SPECTRA-AVERAGE G_{max}

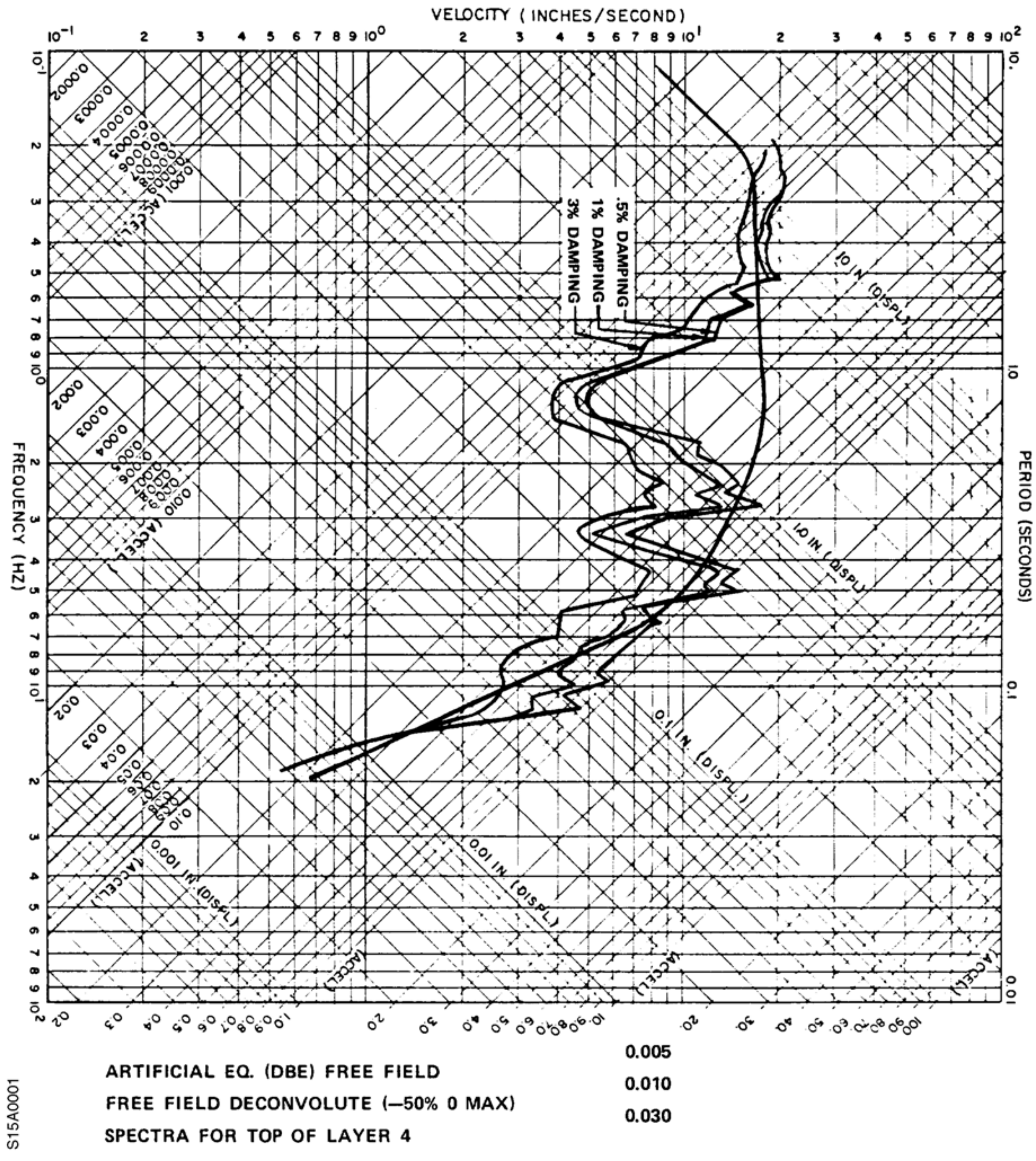
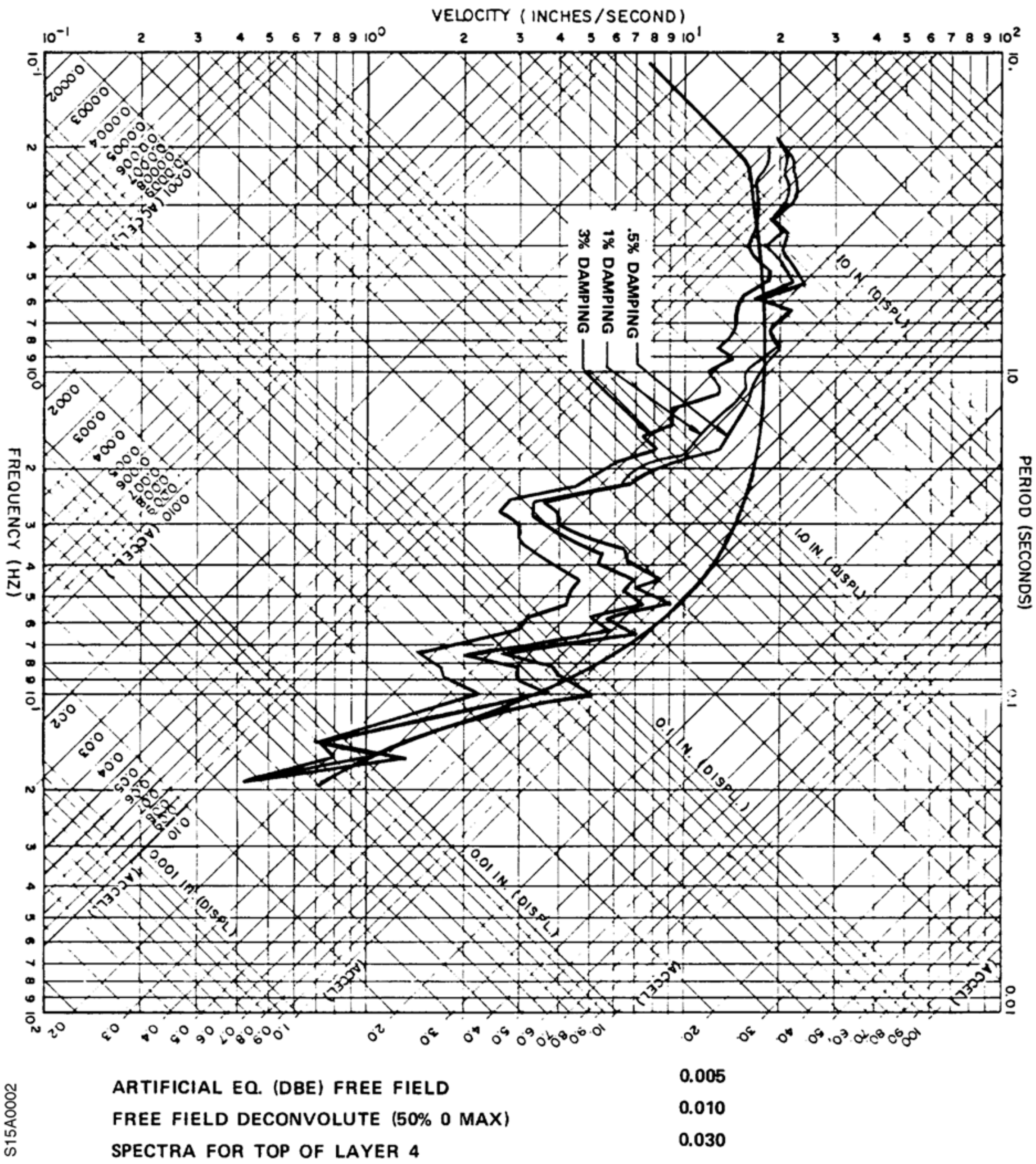
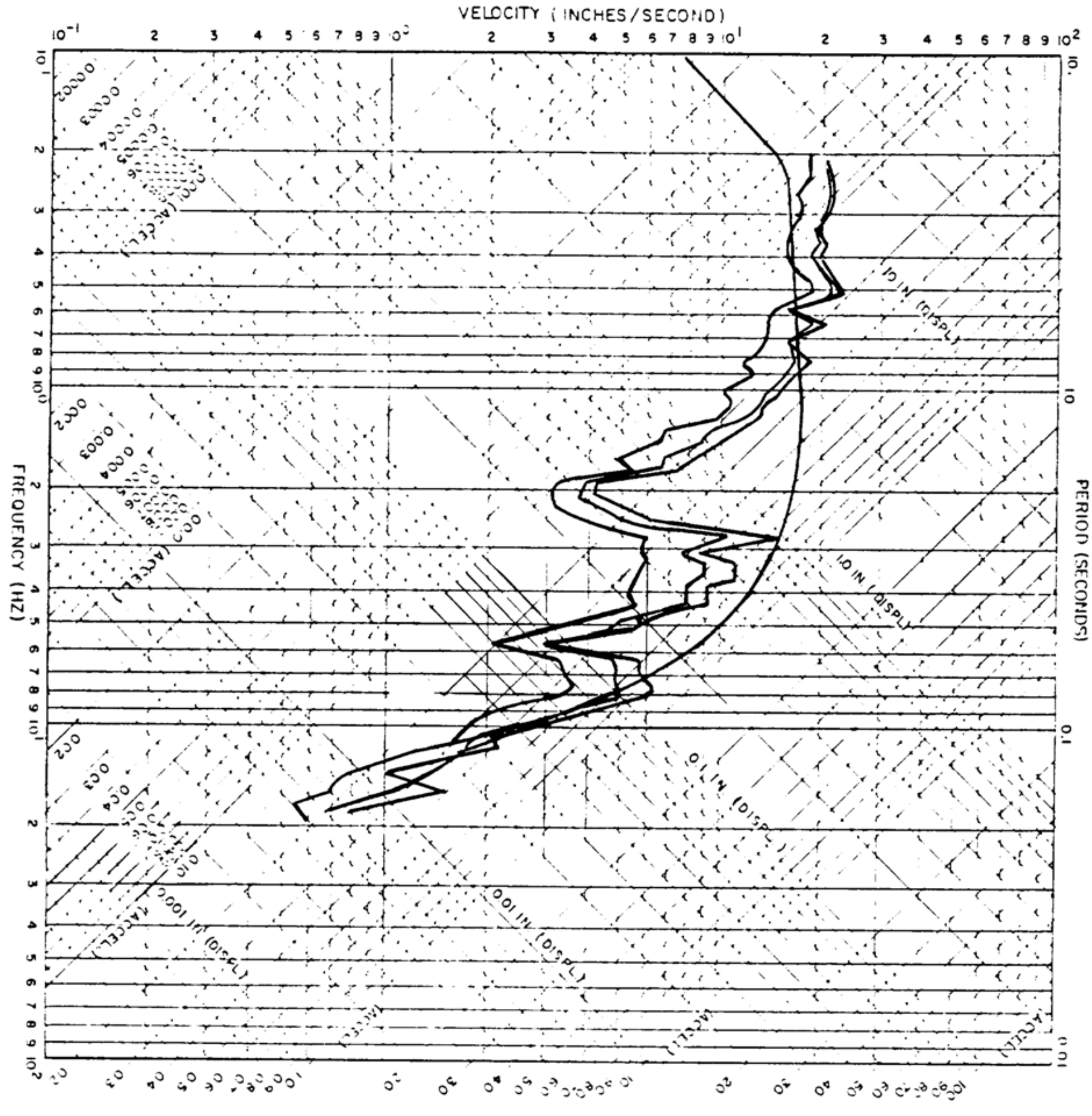


Figure 15A-2
ENVELOPE FOR 0.5% DAMPING
GROUND RESPONSE SPECTRA-AVERAGE G_{max} + 50%



ARTIFICIAL EQ. (DBE) FREE FIELD	0.005
FREE FIELD DECONVOLUTE (50% 0 MAX)	0.010
SPECTRA FOR TOP OF LAYER 4	0.030

Figure 15A-3
ENVELOPE FOR 0.5% DAMPING
GROUND RESPONSE SPECTRA-AVERAGE G_{max} -50%



ARTIFICIAL EQ. (DBE) FREE FIELD	0.006
FREE FIELD DECONVOLUTE (0 MAX)	0.010
SPECTRA FOR TOP OF LAYER 4	0.030

Figure 15A-4
DESIGN LIMITS COMPARED TO EXPERIMENTAL POINTS,
SA 106B CARBON STEEL

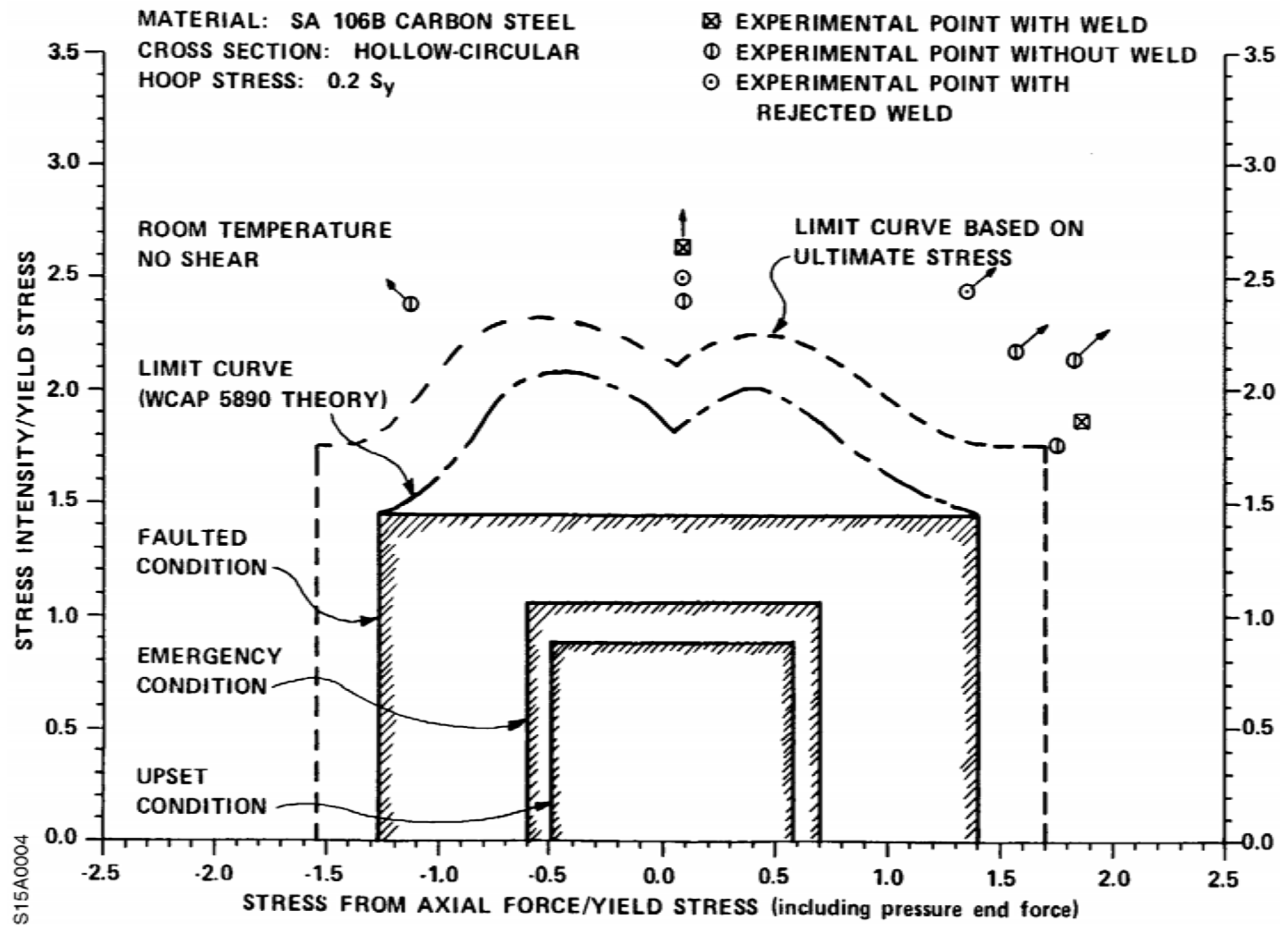


Figure 15A-5
DESIGN LIMITS COMPARED TO EXPERIMENTAL POINTS, 304 STAINLESS STEEL

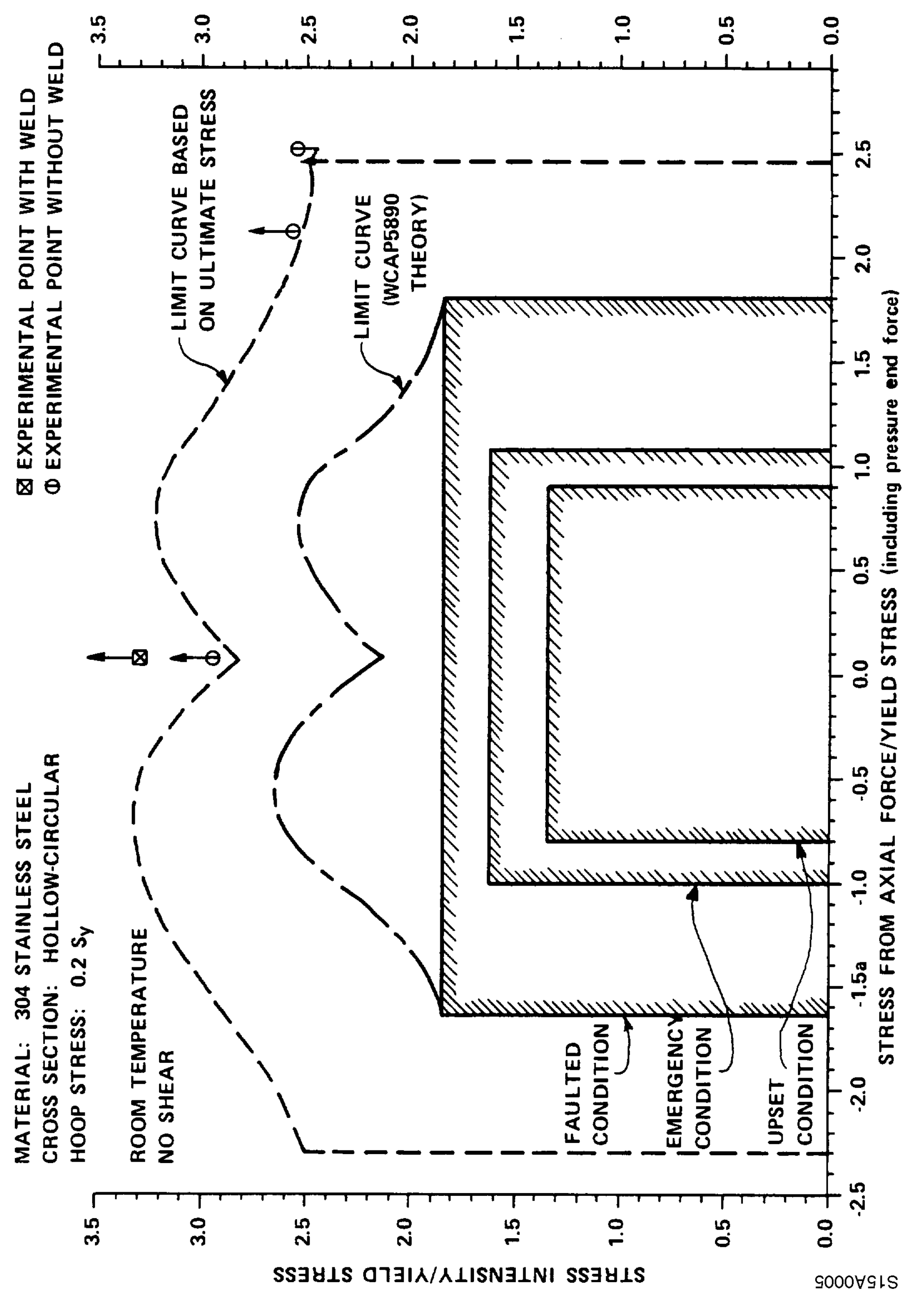


Figure 15A-6
TYPICAL STRESS-STRAIN CURVE, 304 STAINLESS STEEL

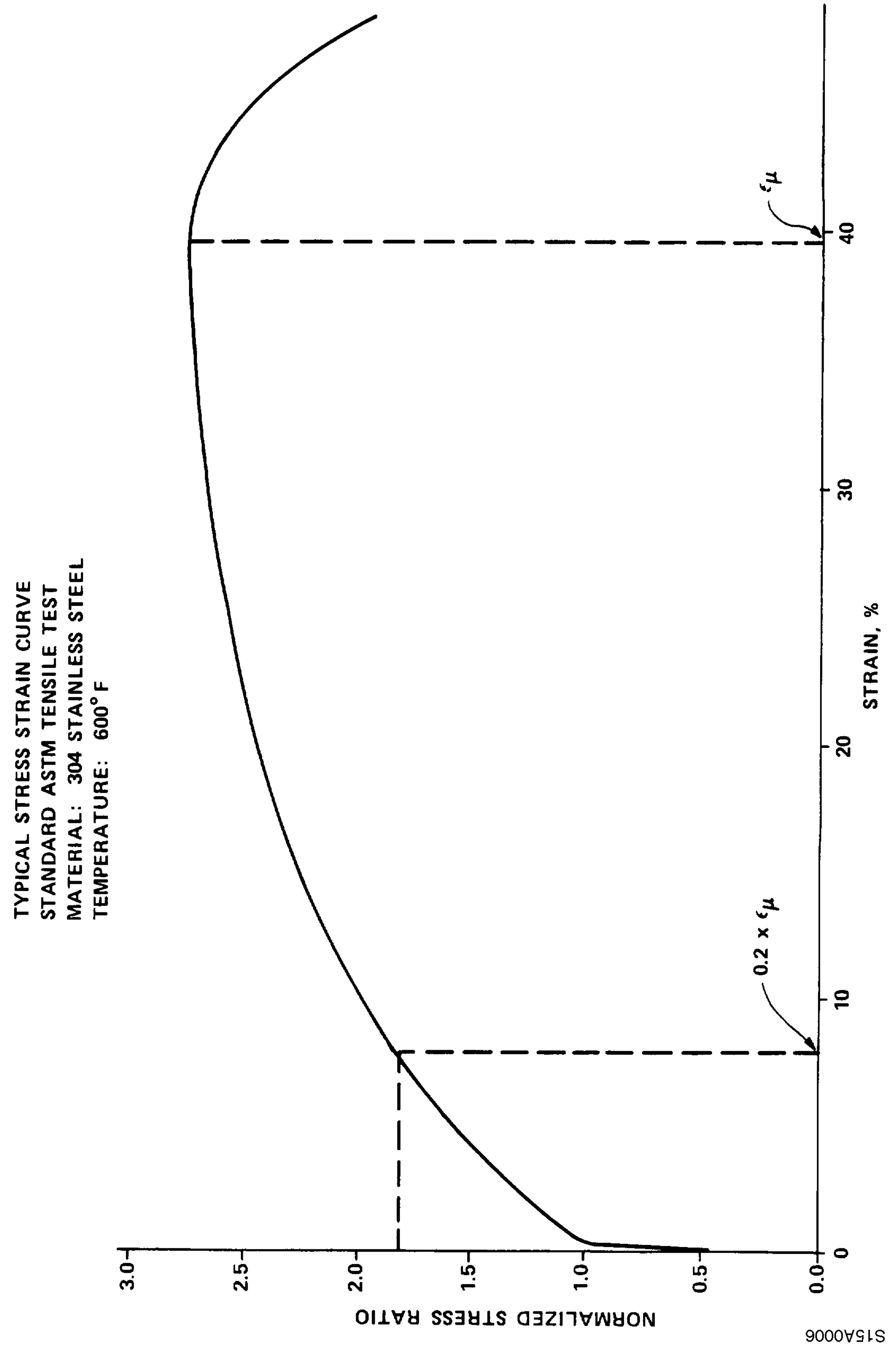


Figure 15A-7
TYPICAL STRESS-STRAIN CURVE, INCONEL 600

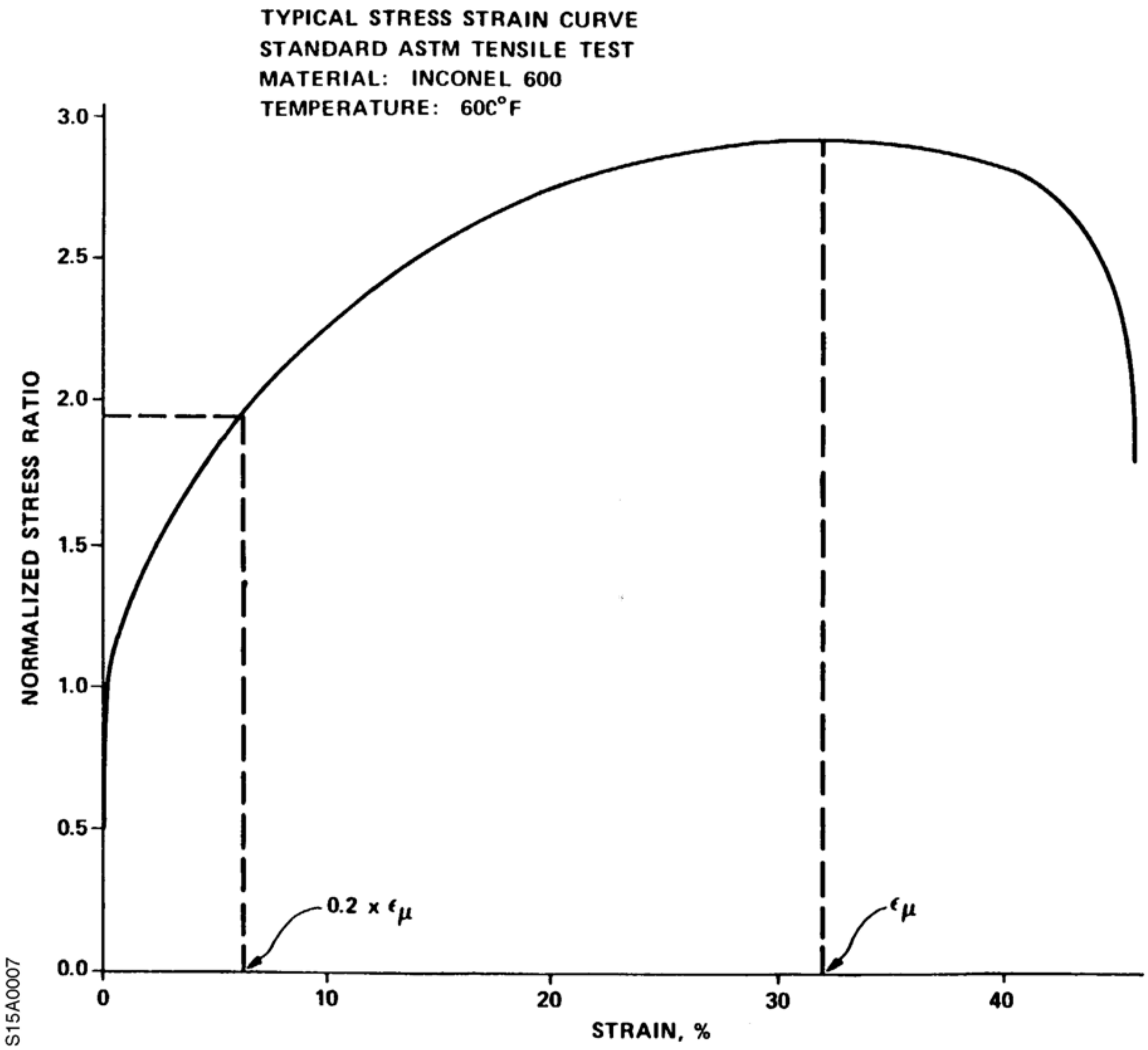
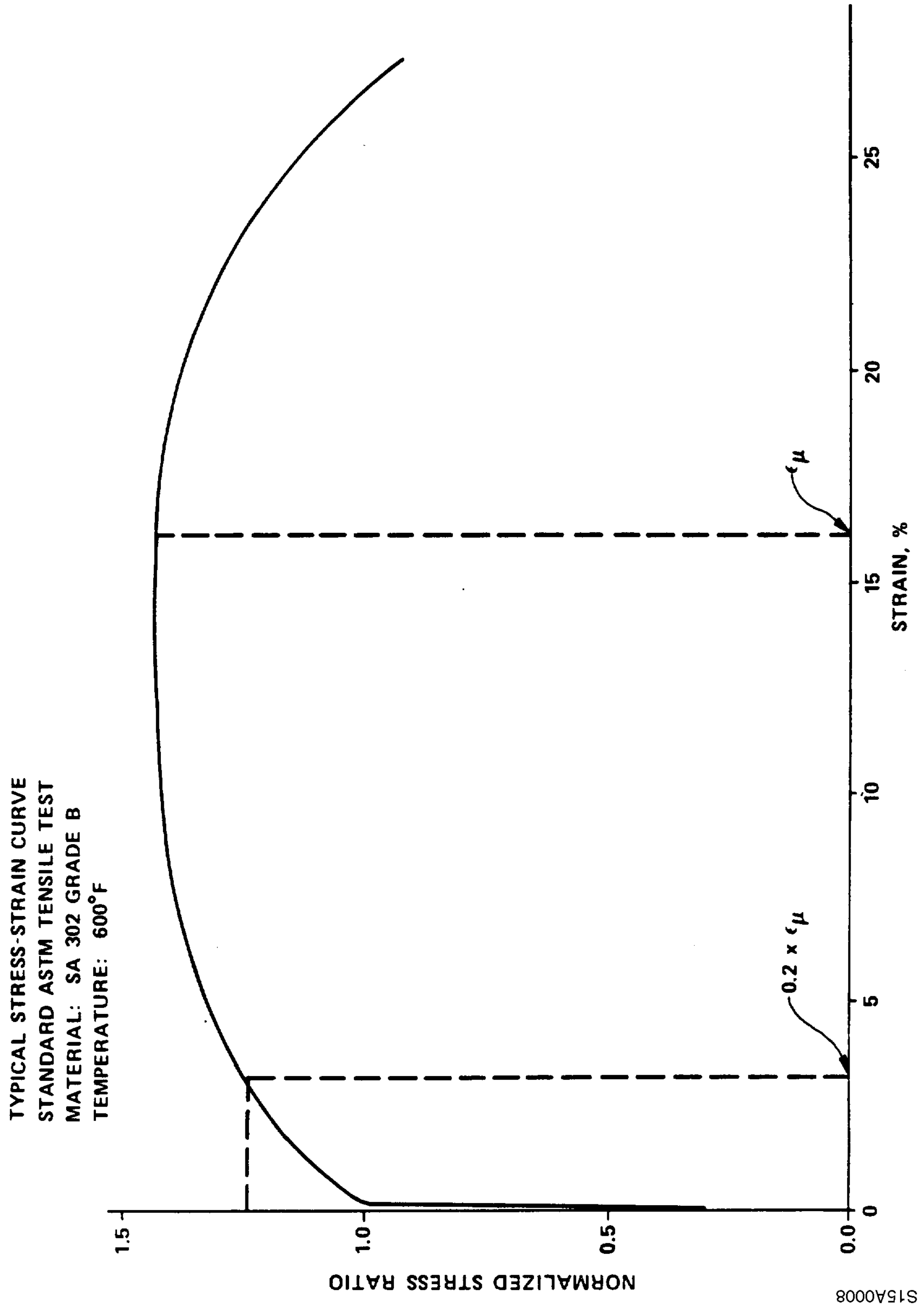


Figure 15A-8

TYPICAL STRESS-STRAIN CURVE, SA 302 GRADE B



Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 16

Intentionally Blank

Chapter 16: Technical Specifications and Technical Requirements
Table of Contents

Intentionally Blank

CHAPTER 16 TECHNICAL SPECIFICATIONS AND TECHNICAL REQUIREMENTS

16.1 TECHNICAL SPECIFICATIONS

Technical Specifications were proposed in accordance with 10 CFR 50.36 during the initial licensing of the plant. The Technical Specifications now reside in Appendix A of the Operating License for each unit.

Technical Specifications define plant variables, operating conditions, surveillance requirements, and administrative controls that are considered necessary to ensure the health and safety of the public.

Intentionally Blank

16.2 TECHNICAL REQUIREMENTS

The Technical Requirements Manual (TRM) contains requirements for plant operation and surveillance of systems formerly contained in the Technical Specifications, along with other selected items. Some requirements were removed from the Technical Specifications as part of NRC and industry efforts to simplify Technical Specifications.

The TRM is controlled by station procedure, and a 10 CFR 50.59 review is required to change the TRM. Changes to the TRM may be made without prior NRC approval, provided that the changes do not involve a license amendment as defined in 10 CFR 50.59. Changes to the TRM that are implemented without prior NRC approval are reported to the NRC in accordance with 10 CFR 50.59. Proposed changes that involve a license amendment are reviewed and approved by the NRC prior to implementation.

Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 17

Intentionally Blank

CHAPTER 17 QUALITY ASSURANCE

The Quality Assurance Program is described in Topical Report DOM-QA-1, Dominion Nuclear Facility Quality Assurance Program Description (QAPD). This topical report provides the QAPD for Dominion's nuclear power stations and independent spent fuel storage installations. The Dominion QAPD conforms to applicable regulatory requirements, such as 10 CFR 50, Appendix B, and approved industry standards, including equivalent alternatives, where identified. This program applies to activities during design, construction, operation, and decommissioning as well as siting. The Dominion QAPD is incorporated by reference and describes how 10 CFR 50, Appendix B requirements are met.

Intentionally Blank

Surry Power Station
Updated Final Safety Analysis Report

Chapter 18

Intentionally Blank

Chapter 18: Programs and Activities That Manage the Effects of Aging
Table of Contents

Chapter 18: Programs and Activities That Manage the Effects of Aging
Table of Contents (continued)

Chapter 18: Programs and Activities That Manage the Effects of Aging
Table of Contents (continued)

Chapter 18: Programs and Activities That Manage the Effects of Aging
Table of Contents (continued)

Chapter 18: Programs and Activities That Manage the Effects of Aging

List of Tables

Intentionally Blank

CHAPTER 18 PROGRAMS AND ACTIVITIES THAT MANAGE THE EFFECTS OF AGING

The following sections provide summary descriptions of the aging management programs (AMPs), which Surry is crediting for the purposes of complying with the license renewal rule, necessary to manage TLAAs and aging of various station systems, structures, and components through the subsequent period of extended operation. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” or require enhancements. Commitments for program additions and enhancements are identified in Section 18.5.

Evaluation summaries of TLAAs applicable to the subsequent period of extended operation are provided in Section 18.3.

This Chapter also includes a discussion on quality assurance and operating experience related to aging management programs.

18.1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

The results of the integrated plant assessment and evaluation of time-limited aging analyses (TLAA) identified new and existing aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) through the subsequent period of extended operation. Section 18.1 and Section 18.2 describe these programs.

Evaluation summaries of TLAAs for the subsequent period of extended operation are provided in Section 18.3.

The U.S. Nuclear Regulatory Commission (NRC) Safety Evaluation Report (SER) (Reference 1) for the Surry subsequent renewed operating licenses identified commitments associated with the future development and enhancement of various aging management programs and activities used to manage aging effects for structures and components for the subsequent period of extended operation. These commitments are compiled and listed in Appendix A of the SER and are listed in Section 18.5, Table 18-1, Subsequent License Renewal Commitments. The associated implementation schedules and a reference to the source(s) are provided for each commitment.

Quality Assurance for Aging Management Process

The Quality Assurance (QA) Program is described in Topical Report DOM-QA-1, “Dominion Energy Nuclear Facility Quality Assurance Program Description,” which implements the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” The QA Program is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position

IQMB-1)," of NUREG-2192. The QA Program provides the basis for the corrective actions, confirmation process, and administrative controls elements of aging management programs (AMPs). The scope of the existing QA Program is expanded to also include safety-related and non safety-related structures and components (SCs) subject to AMPs.

Consideration of Operating Experience in Aging Management Programs (AMPs)

Operating experience (OE) from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the QA Program, which meets the requirements of 10 CFR 50, Appendix B, and the OE program, which meets the requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff."

The Dominion OE program interfaces with and relies on active participation in the INPO OE program, as endorsed by the NRC. In accordance with these programs, all incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development is also reviewed. Items so identified are further evaluated and the AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed. Training on age-related degradation and aging management is provided to those personnel responsible for implementing the AMPs and to those who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry OE. Plant-specific OE associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the Dominion OE program.

18.1.1 ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is an existing condition monitoring program that manages cracking, loss of fracture toughness, and loss of material. The program consists of periodic volumetric, surface, and/or visual examinations and leakage tests of ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, identification of signs of degradation, and establishment of corrective actions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is implemented in accordance with 10 CFR 50.55a and ASME Code, Section XI. The ASME Code, Section XI, edition and addenda used will be consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation. Additional examinations associated with the ASME Code, Section XI, Inservice Inspection program are identified in the Augmented Inspection program, and are included in the ISI Schedule, for the following components:

- Sensitized stainless steel [Class 1, Class 2, and Containment and Recirculation Spray]
- High energy lines outside of Containment [Main Steam and Feedwater lines]

- Component supports [the first seismic restraint beyond the defined ASME functional isolation boundary]
- Steam generator feedwater nozzles [feedwater piping welds from the steam generators to the first elbow]
- Pressurizer instrument connections
- Pressurizer surge line
- MRP-146 thermal stratification inspections

Inspections for three other aspects of the Augmented Inspection program are included in non-ISI programs. Inspections of Reactor Vessel Incore Detector Thimble Tubes are described in the Flux Thimble Tube Inspection program (18.1.24). Inspections of the Reactor Vessel Head are described in the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components program (18.1.5). Inspections of the PWR vessel internals are described in the PWR Vessel Internals program (18.1.7).

18.1.2 Water Chemistry

The Water Chemistry program is an existing preventive program that manages loss of material, cracking, reduction of heat transfer, and wall thinning of components exposed to a reactor coolant, steam, treated borated water, and treated water environment.

The scope of the Primary Water Chemistry program includes monitoring and control of the chemical environment in the reactor coolant system and related pressurized water reactor interfacing systems. The Primary Water Chemistry program is consistent with Electric Power Research Institute (EPRI) Report 3002000505, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” Revision 7.

The scope of the Secondary Water Chemistry program includes monitoring and control of the chemical environment in the steam generator secondary side and the secondary cycle systems. The Secondary Water Chemistry program is consistent with EPRI Report 3002010645, “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” Revision 8.

The primary and secondary water chemistry control strategies are set forth in strategic plans and implemented by procedures. The programmatic control of the chemical environment ensures that the aging effects due to contaminants (e.g., chloride, fluoride, and sulfate) are limited. The methods used to manage both the primary and secondary chemical environments rely on the principles of: (1) limiting the concentration of chemical species known to cause corrosion and (2) addition of chemical species known to inhibit material degradation by their influence on pH and dissolved oxygen levels.

The One-Time Inspection program (18.1.20) verifies the effectiveness of the Water Chemistry program.

18.1.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting program is an existing condition monitoring program that manages cracking and loss of material for the reactor head closure stud assembly (which includes the closure studs, nuts and washers) and for the threads in the reactor vessel flange.

The Reactor Head Closure Stud Bolting program is implemented through procedures based on the examination requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1 and preventive measures to mitigate cracking. The program relies on preventive measures to address reactor head closure stud bolting degradation consistent with those identified in NRC Regulatory Guide 1.65, Revision 1, “Material and Inspection for Reactor Vessel Closure Studs.”

18.1.4 Boric Acid Corrosion

The Boric Acid Corrosion program is an existing condition monitoring program that manages loss of material due to leaking borated water on structures and components (including electrical equipment / junction boxes) within the scope of subsequent license renewal that are susceptible to boric acid corrosion. The program provides for identification of leakage through inspection and examination. When leakage is identified, a visual inspection is performed that identifies the leakage pathway and any boric acid residue on adjacent structures, components, and supports so that leakage clean-up can be initiated, and corrective actions can be implemented as necessary. This program includes provisions to initiate evaluations and assessments when leakage is discovered by activities not associated with the program, such as routine plant walkdowns and surveys. When it is determined that an evaluation is necessary, it is performed in a timely manner.

The Boric Acid Corrosion program relies in part on NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. The program is consistent with Section 7 of WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors.” Additionally, the program includes examinations conducted during inservice inspection pressure tests performed in accordance with ASME Code, Section XI, requirements.

18.1.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

The Cracking of Nickel-alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program is an existing condition monitoring program that manages loss of material and cracking due to primary water stress corrosion cracking (PWSCC) for components or welds constructed from Alloy 600/82/182 and exposed to pressurized water reactor primary coolant at elevated temperatures. Initiation and growth of PWSCC cracks can occur as a function of variables which include, but are not limited to temperature, stress, microstructure, time, and water chemistry. This program is used in conjunction with the Water Chemistry program (18.1.2).

The Cracking of Nickel-alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program is patterned after the industry guidance document, “Materials Reliability Program: Generic Guidance for Alloy 600 Management,” (MRP-126). Bare-metal visual, surface, and volumetric examinations are used to detect the presence of PWSCC. Inspections are performed periodically.

The nickel-alloy components that are inspected due to susceptibility to PWSCC include the reactor vessel bottom-mounted instrumentation nozzles and J-groove welds (ASME Code Case N-722, as incorporated by reference in 10 CFR 50.55a). Other nickel-alloy components that are inspected, but are resistant to PWSCC, include the reactor vessel head penetration nozzles and J-groove welds (ASME Code Case N-729, as incorporated by reference in 10 CFR 50.55a). There are no susceptible nickel-alloy branch line connections that would require a baseline volumetric or inner diameter surface inspection in accordance with ASME Code Case N-770, as incorporated by reference in 10 CFR 50.55a. The Cracking of Nickel-alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program inspects components that are susceptible to corrosion due to boric acid leakage from nearby or adjacent nickel-alloy components previously described.

18.1.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program is an existing condition monitoring program that manages loss of fracture toughness of cast austenitic stainless steel reactor coolant pressure boundary components with service conditions above 250 °C (Celsius) [482 °F (Fahrenheit)].

The program determines the susceptibility of CASS piping and piping components in reactor coolant pressure boundaries with regard to thermal aging embrittlement based on the casting method, molybdenum content, and ferrite percentage.

Aging management of potentially susceptible piping and piping components is accomplished through a component-specific flaw tolerance evaluation in accordance with the ASME Code, Section XI. Based on the completed flaw tolerance evaluation in WCAP-18258, “Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2,” flaw crack growth remains acceptable for the subsequent period of extended operation.

For valve bodies, screening for significance of thermal aging embrittlement is not required. The existing ASME Code, Section XI visual inspection requirements are adequate for valve bodies. The existing ASME Code, Section XI visual inspection requirements are also adequate for managing the aging effects of reactor coolant pump casings because the original flaw tolerance evaluation performed as part of Code Case N-481 remains bounding and is applicable for the subsequent period of extended operation as described in Section 18.3.7.6, Reactor Coolant Pump Code Case N-481.

18.1.7 PWR Vessel Internals

The PWR Vessel Internals program is an existing condition monitoring program that manages cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of pre-load for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking, primary water stress corrosion cracking, irradiation-assisted stress corrosion cracking, and cracking due to fatigue/cyclic loading. Degradation due to loss of material can be induced by wear, and loss of fracture toughness is the result of thermal aging and neutron irradiation embrittlement. Potential causes for the aging effect of changes in dimensions are void swelling or distortion, and loss of pre-load can result from thermal and irradiation-enhanced stress relaxation or creep.

The PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in Electric Power Research Institute (EPRI) Technical Report 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)," and EPRI Technical Report 1016609, "Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals (MRP-228)," to manage the aging effects on the reactor vessel internal components, as supplemented by a gap analysis. The gap analysis includes integration of EPRI Technical Report 3002005349, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," (MRP-227, Revision 1), which is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, "Guideline for the Management of Materials Issues". MRP-227, Revision 1, includes one "mandatory" and four "needed" NEI 03-08 implementation requirements for the PWR Vessel Internals program. The guidelines listed in MRP-227, Revision 1, provide an appropriate aging management methodology for the RVI components. The gap analysis also integrates the interim guidance from MRP 2018-022, "Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants". The inspections of the RVI components are implemented in accordance with EPRI Report 3002005386, "Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2015 Update (MRP-228, Rev. 2)".

The Safety Evaluation Report that the NRC issued for the approved version (i.e., MRP-227-A) of MRP-227, Revision 0, dated December 16, 2011, included eight Applicant/Licensee Action Items (A/LAI) that required resolution. Six of those items are applicable for Westinghouse reactors. The six items that require resolution for SPS have been addressed such that no open items exist for the PWR Vessel Internals program in preparation for the subsequent period of extended operation.

18.1.8 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Erosion monitoring is performed for the internal surfaces of metallic piping and components to manage the aging effect of wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The program is consistent with the Virginia Electric and Power Company response to NRC Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning,” and relies on implementation of EPRI guidelines listed in NSAC-202L, Revision 4, “Recommendations for an Effective Flow Accelerated Corrosion Program.” The erosion activity implements the recommendations of EPRI 3002005530, “Recommendations for an Effective Program Against Erosive Attack.”

The program includes (a) identifying all flow accelerated corrosion (FAC)-susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analyses of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC modeling.

The program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ software. The CHECWORKS-SFA™ model is evaluated and updated as required to reflect any significant changes in plant operating parameters such as power uprates. Wall thinning information available from the CHECWORKS-SFA™ software is one of the tools used to determine the scope and required schedule for inspections of FAC-susceptible components.

In addition to planned inspections performed for the Flow-Accelerated Corrosion program, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation.

18.1.9 Bolting Integrity

The Bolting Integrity program is an existing condition monitoring program that manages cracking, aging by performing periodic visual inspections for indications of cracking, loss of material due to, general, pitting, and crevice corrosion, microbiologically-influenced corrosion, wear and loss of preload as evidenced by leakage for safety-related and non safety-related closure bolting on pressure-retaining components within the scope of subsequent license renewal.

The program refers to NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants”. NUREG-1339 includes guidance from EPRI report NP-5067, “Good Bolting Practices Volume 1 (Large Bolt Manual),” and from EPRI report NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants”.

The listing for EPRI NP-5769 mentions an exception noted in NUREG-1339 for safety-related bolting. That exception is applicable for bolting used in pressure-retaining applications, and indicates that experimentally–verified fastener material properties and fracture mechanics evaluations should be used to ensure that safety-related fasteners are unlikely to be susceptible to stress corrosion cracking. EPRI Report 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” is applicable for the Bolting Integrity program, and states that applicable material properties should be confirmed with the fastener manufacturer. EPRI Report 1015336 includes guidance for preventing or mitigating stress corrosion cracking by the proper selection of bolting. Table B-1 of EPRI Report 1015336 lists appropriate bolting, and is a reference for the bolting design standard at SPS.

The program includes guidance provided by EPRI reports 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” and 1015337, “Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints,” for assembling bolted connections, and for performing visual examinations of pressure-retaining closure bolting. Preventive measures to preclude or mitigate cracking and loss of preload include proper selections of bolting material and lubricant, and proper application of preload. The absence of high-strength pressure-retaining closure bolting precludes the need for volumetric inspections.

The program addresses management of age-related degradation for applicable submerged bolting, and for piping systems that contain compressed air, hydrogen gas, nitrogen gas, and carbon dioxide.

The ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD program (Section 18.1.1) includes inspections of closure bolting within the scope of ASME Code, Section XI, and supplements this Bolting Integrity program. The reactor vessel closure head studs are addressed in the Reactor Head Closure Stud Bolting program (Section 18.1.3). The following aging management programs for SPS manage aging effects associated with safety-related and non safety-related structural bolting:

- ASME Section XI, Subsection IWE program (Section 18.1.29)
- ASME Section XI, Subsection IWF program (Section 18.1.31)
- Structures Monitoring program (Section 18.1.34)
- Inspection of Water-Control Structures Associated With Nuclear Power Plants program (Section 18.1.35)
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program (Section 18.1.13)

The External Surfaces Monitoring of Mechanical Components program (Section 18.1.23) describes the inspections for non-ASME pressure-retaining bolting.

18.1.10 Steam Generators

The Steam Generators program is an existing condition monitoring program that manages the aging effects of cracking, loss of material (e.g., wall thinning), and reduction of heat transfer for the steam generators. The scope of the program includes primary-side components (e.g., U-tubes [tubes], plugs, sleeves, channel head divider plate, channel head, tubesheet, etc.), and secondary-side components that are contained within the steam generator. The program uses volumetric inspections for the tubes, and visual inspections for the other primary-side and secondary-side components. The visual inspections of the primary-side components listed above are performed in accordance with the Degradation Assessment (DA) that is prepared as each steam generator is scheduled for examination. Tube-to-tubesheet welds do not require aging management because the H* alternate repair criteria have been permanently approved to eliminate those hot-leg and cold-leg welds as reactor coolant pressure boundaries.

Provisions in the Steam Generators program address reporting criteria, inspection scope and frequency, assessments, plugging criteria, and water chemistry monitoring to maintain consistency with established requirements. NEI 97-06, Revision 3, “Steam Generator Program Guidelines” and associated EPRI guidelines provide a generic industry program to implement Technical Specifications.

As stated in the steam generator DA, tubing and primary-side inspections typically are performed every other refueling outage for each steam generator, thus satisfying the guidance for visual inspections to be performed at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections.

The Steam Generators program includes preventive measures to mitigate aging related to corrosion phenomena through foreign material exclusion as a means to inhibit tube degradation due to wear. Identification of deposits on the secondary-side of the steam generator, and the subsequent removal of sludge deposits help avoid tube degradation.

The Technical Specifications include the following requirements which are included in the Steam Generators program:

- Conducting condition monitoring assessments for each refueling outage during which steam generator tubes are inspected or plugged.
- Maintaining steam generator tube integrity by meeting performance criteria for tube structural integrity, accident-induced leakage, and operational leakage.
- Installing plugs in tubes found by inservice inspection to contain flaws that exceed acceptance criteria.

- Performing periodic inspections of steam generator tubes. Inspection scope, methods, and interval, ensure that tube integrity is maintained until the next planned inspection.
- Monitoring primary-to-secondary leakage.
- Monitoring secondary water chemistry to ensure controls are in place to inhibit steam generator tube degradation.

18.1.11 Open-Cycle Cooling Water System

The Open Cycle Cooling Water System program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages loss of material, reduction of heat transfer, flow blockage, cracking, and loss of coating or lining integrity, for the piping, piping components, and heat exchangers identified by the Dominion Energy responses to NRC Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to NRC GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. This program includes enhancements to the guidance in NRC GL 89-13 that address operating experience such that aging effects are adequately managed.

System and component testing, visual inspections, nondestructive examination (e.g., ultrasonic testing, eddy current testing and acoustic impact tap examination), and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained. Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the Virginia Electric and Power Company commitments to GL 89-13 to verify heat transfer capabilities.

The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (18.1.28) will manage the aging effects of internal surface coatings except those of metallic surfaces lined with Carbon Fiber Reinforced Polymer that is used as a pressure boundary.

18.1.12 Closed Treated Water Systems

The Closed Treated Water Systems program is an existing program that manages loss of material, cracking, and reduction of heat transfer for components exposed to a closed treated water environment.

This is a mitigation program that also includes a condition monitoring program to verify the effectiveness of the mitigation activities. The program consists of: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion are minimized; (b) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. The program uses as applicable, EPRI Report 3002000590, “Closed Cooling Water Chemistry Guideline”. Microbiological testing is performed as a diagnostic chemistry parameter for selected system water treatments.

18.1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program is an existing condition monitoring program that manages cracking, loss of material due to corrosion and wear, and loss of preload on bolted connections for cranes and hoists within the scope of subsequent license renewal. The program includes periodic visual inspections to detect degradation of bridge, rail, and trolley structural components and indications of loss of preload on bolted connections. This program relies on the guidance in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” ASME B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” ASME B30.11, “Monorail Systems and Underhung Cranes,” and ASME B30.16, “Overhead Hoists (Underhung).”

For those cranes or hoists associated with Time-Limited Aging Analyses, the effects of past and future usage, including the number and magnitude of lifts, are evaluated in Section 18.3.7.1, Crane Load Cycle Limits.

18.1.14 Compressed Air Monitoring

The Compressed Air Monitoring program is an existing preventive and condition monitoring program that manages loss of material. The Compressed Air Monitoring program includes monitoring of air moisture content and contaminants such that specified limits are maintained, and performance of opportunistic inspections of components for indications of loss of material.

This program is based on the Surry response to NRC GL 88-14, “Instrument Air Supply Problems;” and utilizes guidance and standards provided in EPRI TR 108147 “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079,” and ANSI/ISA-S7.3-1975, “Quality Standard for Instrument Air.” The Compressed Air Monitoring program activities implement the moisture content and contaminant criteria of ANSI/ISA-S7.3-1975 (incorporated into ISA-S7.0.01-1996).

Program activities include air quality checks at various locations to ensure that dew point, particulates, and hydrocarbons are maintained within the specified limits. Opportunistic inspections of the internal surfaces of select compressed air system components for signs of loss of material will be performed.

18.1.15 Fire Protection

The Fire Protection program is an existing condition and performance monitoring program comprised of functional tests and visual inspections. The program manages:

- loss of material for fire-rated doors, fire damper assemblies, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- loss of material (spalling) or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- loss of material, change in material properties, cracking/delamination, and separation for non-elastomer fire barrier penetration seals, fire stops, fire wraps, and coatings cracking/delamination, and separation
- loss of material and cracking for aluminum seismic gap covers

This program includes fire barrier inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, fire damper assemblies, and periodic visual inspection and functional tests of fire-rated doors to demonstrate that their operability is maintained. The program also includes periodic inspections and functional tests of the halon systems and low-pressure carbon dioxide systems.

18.1.16 Fire Water System

The Fire Water System program is an existing condition monitoring program that manages cracking, loss of material, flow blockage due to fouling, and loss of coating integrity for in-scope water-based fire protection systems. This program manages aging effects by conducting periodic visual inspections, flow testing, and flushes consistent with provisions of the 2011 Edition of National Fire Protection Association (NFPA) 25. Testing of sprinklers that have been in place for 50 years is performed consistent with NFPA 25, 2011 Edition. With exception of two locations, portions of the water-based fire protection system that have been wetted but are normally dry have been confirmed to drain and are not subjected to augmented testing and inspections.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed and the source is detected and corrected. Non-code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard.

18.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The Outdoor and Large Atmospheric Metallic Storage Tanks program is an existing condition monitoring program that manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program is a condition monitoring program that manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), emergency condensate storage tanks (ECSTs), and the emergency condensate makeup tanks (ECMTs). This program also manages aging of the fire protection/domestic water storage tanks (FWSTs) bottom surfaces exposed to soil. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. The RWSTs are insulated and rest on a concrete foundation covered with an oil sand cushion. Caulking is used at t he concrete-component interface of the RWSTs. The ECSTs and ECMTs are internally coated and protected by concrete missile barriers. Weep holes, located around the circumference of the ECSTs where the concrete missile shield meets the concrete foundation, allow drainage of leakage or condensation to the outside perimeter of the ECSTs. The weep holes will be inspected for water leakage once each refueling cycle. The CATs are skirt supported and insulated with sprayed-on rigid polyurethane foam.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Surface exams of external tank surfaces are conducted to detect cracking on the stainless steel tanks. Inspections of RWST caulking are supplemented with physical manipulation. Thickness measurements of the tanks bottoms are conducted to ensure that significant degradation is not occurring. The external surfaces of insulated tanks are periodically sampling-based inspected. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions.

The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (18.1.28) will manage the internally coated surfaces of the ECSTs and ECMTs. Internal surfaces of the RWSTs and CATs will be managed by the One-Time Inspection program (18.1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs and ECMTs will be managed by the Structures Monitoring program (18.1.34).

18.1.18 Fuel Oil Chemistry

The Fuel Oil Chemistry program is an existing mitigative and condition monitoring and preventive program that manages loss of material and reduction of heat transfer from tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

The fuel oil tanks within the scope of subsequent license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the Technical Requirements Manual, and ASTM standards such as ASTM D 975, D 1796, D 6217, and D 4057. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil.

Fuel oil tanks are periodically drained of water and accumulated sediment, cleaned, and internally inspected when accessible. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks are performed in lieu of cleaning and internal inspection. Tanks that cannot be cleaned and internally inspected, and are physically inaccessible for bottom thickness measurements, are monitored for leakage consistent with the current licensing basis.

18.1.19 Reactor Vessel Material Surveillance

The Reactor Vessel Material Surveillance program is an existing condition monitoring program that manages reduction of fracture toughness of the ferritic reactor vessel beltline materials, in accordance with the version of ASTM E-185 available and used during fabrication of the reactor vessels. The program provides sufficient material to monitor reduction of fracture toughness due to neutron irradiation embrittlement until the end of the subsequent period of extended operation, and determine the need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence.

The Reactor Vessel Material Surveillance program was developed by Westinghouse Electric Company prior to 10CFR50 Appendix H. The Reactor Vessel Material Surveillance program consists of two elements. The first element is related to the number of capsules, location of capsules, and content of specimens. The second element is related to the test methods and schedule for testing. For the first element, related to the design of the program, WCAP-7723, “Virginia Electric and Power Co. Surry Unit No. 1 Reactor Vessel Radiation Surveillance Program” and WCAP-8085, “Virginia Electric and Power Co. Surry Unit No. 2 Reactor Vessel Radiation Surveillance Program” for Units 1 and 2, documented the program. The Reactor Vessel Material Surveillance program for Unit 1 meets either ASTM E 185-66 or ASTM E 185-70. WCAP-8085 states that the Unit 2 Reactor Vessel Material Surveillance program meets ASTM E-185-70. Initially, the requirements relating to the testing method was not mandated by the NRC through a particular version of ASTM E185. Therefore, when a capsule was removed from the reactor vessel, it was customary at the time to document which version of ASTM E185 was used for testing. Overtime, the NRC began the process of approving various editions of ASTM E185 for testing. To date, for testing and schedule considerations, the NRC has approved three editions of ASTM E185-73, -79, and -82. Currently, the Reactor Vessel Material Surveillance program complies with ASTM E-185-82 for testing and scheduling. Since the withdrawal schedule in Table 1 of ASTM E 185-82 is based on plant operation during the original 40-year initial license term, standby capsules have been incorporated to ensure appropriate monitoring during the subsequent period of extended operation. The Reactor Vessel Material Surveillance program includes removal and testing of at least one capsule, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criteria has not been tested previously, then at least one capsule will be removed and tested during the subsequent period of extended operation (or earlier) to meet this criterion.

Data from the Reactor Vessel Material Surveillance program is used to monitor neutron irradiation embrittlement of the reactor vessel, and is provided as input to the neutron embrittlement time-limited aging analyses described in Section 18.3.2, Reactor Vessel Neutron Embrittlement Analysis.

In accordance with 10 CFR Part 50, Appendix H, all surveillance capsules, including those previously removed from the reactor vessel, meet the test procedures and reporting requirements of ASTM E 185-82, to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including the conversion of standby capsules into the Appendix H program and extension of the surveillance program for the subsequent period of extended operation, are submitted for approval by the Nuclear Regulatory Commission (NRC) prior to implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future insertion. If one or more capsules will not be maintained in such a way as to permit future insertion, then the NRC will be notified of the change.

The Reactor Vessel Material Surveillance program is also used in conjunction with the Neutron Fluence Monitoring program (18.2.2) which monitors neutron fluence for reactor vessel components and reactor vessel internal components.

18.1.20 One-Time Inspection

The One-Time Inspection program is a new condition monitoring program that will manage loss of material, cracking, and reduction of heat transfer of components containing reactor coolant, treated borated water, secondary water, fuel oil, or lubricating oil environments.

The One-Time Inspection program will conduct one-time inspections of susceptible locations to verify the effectiveness of the Water Chemistry program (18.1.2), the Fuel Oil Chemistry program (18.1.18), and Lubricating Oil Analysis program (18.1.26). The program will verify either no unacceptable age-related degradation is occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the subsequent period of extended operation. For steel components exposed to environments that do not include corrosion inhibitors, the One-Time Inspection program will verify that long-term loss of material will not result in a loss of intended function.

The elements of the One-Time Inspection program will include: (a) determination of sample size for the components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the subsequent period of extended operation.

This program will not be used for components with known age-related degradation mechanisms, or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Periodic inspections will be conducted in those cases.

ASME Code components and non-ASME Code components will be inspected using procedures consistent with the ASME Code.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

18.1.21 Selective Leaching

The Selective Leaching program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc or greater than 8% aluminum).

One-time inspections for components exposed to closed-cycle cooling water or treated water environments will be conducted when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. Visual inspections coupled with mechanical examination techniques such as chipping or scraping will be conducted. Periodic destructive examinations of components for physical properties (i.e., degree of de-alloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments or for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments.

Inspections and tests will be conducted to determine whether loss of material will affect the ability of the components to perform their intended function for the subsequent period of extended operation. Inspections are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures will include requirements for items such as lighting, distance, offset, and surface conditions. When the acceptance criteria are not met such that it is determined that the affected component be replaced prior to the end of the subsequent period of extended operation, additional inspections will be performed.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

18.1.22 ASME Code Class 1 Small-Bore Piping

The ASME Code Class 1 Small-Bore Piping program is a new condition monitoring program that will manage cracking in ASME Code Class 1 small-bore piping that is defined as greater than or equal to one inch nominal pipe size (NPS) and less than four inches NPS. This program will utilize volumetric examination techniques demonstrated to be capable of detecting cracking, or destructive examinations to augment the visual examinations (VT-1) required by the ASME Code, Section XI. One-time inspections will determine the presence of cracking for locations within the scope of the ASME Code Class 1 Small-Bore Piping program. With the exception of socket welds for the seal injection line attachments to the reactor coolant pump (RCP) thermal barrier casings at the seal injection nozzles, there is no operating experience of age-related cracking. Therefore, except for those seal injection socket welds, inspection samples will be selected consistent with NUREG-2191 Section XI.M35, Table XI.M35-1, Category A. One-time inspection samples will consist of 3% of the total population in each unit (up to ten maximum) for susceptible butt welds and susceptible socket welds. Each socket weld subject to destructive examination can be credited twice toward the total number of examinations.

For the socket welds on the seal injection lines to the RCP thermal barrier casings, Category B from NUREG-2191, Section XI.M35, Table XI.M35-1 is applicable due to the cracking that occurred in 1998. However, an exception will be taken for the volumetric inspections. As a result of exceedingly limited space in the area of the seal injection line to the thermal barrier casing, a meaningful volumetric examination is not feasible. Volumetric examination could be performed only if the RCP assembly is disassembled for maintenance which could provide for an opportunistic volumetric examination. In lieu of a volumetric examination, a liquid penetrant (LP) examination, that can be performed when sufficient accessibility exists, will provide an acceptable level of information regarding the integrity of the weld. The LP examination for the seal injection line weld at one of the three RCPs will be performed prior to the subsequent period of extended operation. Examinations for the seal injection line welds at the two remaining RCPs will be performed, one per ISI interval, during the subsequent period of extended operation.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

18.1.23 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components program is an existing condition monitoring program that manages loss of material, cracking, and reduction of heat transfer of metallic components; hardening or loss of strength, loss of material, and cracking or blistering of polymeric components; loss of preload of HVAC closure bolting; and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) are conducted. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual inspections conducted under this program.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel, aluminum and copper alloy (>15% Zn or >8% Al) components.

A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), are periodically inspected every ten years during the subsequent period of extended operation. Following insulation removal, surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect loss of material and cracking of the component surfaces.

Non-ASME Code inspection procedures include inspection parameters such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

The external surfaces of components that are buried or in underground environments are inspected by the Buried And Underground Piping And Tanks program (18.1.27). The external surfaces of outdoor tanks and indoor large volume metallic storage tanks (capacity >100,000 gallons) are inspected by the Outdoor and Large Atmospheric Metallic Storage Tanks program (18.1.17). Loss of material due to boric acid corrosion is managed by the Boric Acid Corrosion program (18.1.4).

18.1.24 Flux Thimble Tube Inspection

The Flux Thimble Tube Inspection program is an existing condition monitoring program that manages loss of material due to wear by inspecting for the thinning of flux thimble tube walls. Flux thimble tubes provide a path for the in-core neutron flux monitoring system detectors and forms part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel (RV) where flow-induced fretting causes wear at discontinuities in the path from the RV instrument nozzle to the fuel assembly instrument guide tube. The thimble tube design is a double-walled, asymmetrical configuration to accommodate thermocouple leads located in the annulus between the inner and outer flux thimble tubes. The outer tube is the component that is most susceptible to wear due to its contact with the discontinuities. The inner tube through which the incore detector travels is the reactor coolant system pressure boundary. The double wall design significantly reduces the potential for wear of the inner tube pressure boundary. Periodic eddy current examinations are performed to confirm the integrity of the inner flux thimble tube, and are consistent with the recommendations of NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.”

18.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is an existing condition monitoring program that manages loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, gas, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) within the scope of the Open-Cycle Cooling Water System program (18.1.11), Closed Treated Water Systems program (18.1.12), and Fire Water System program (18.1.16) are not managed by this program. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel, aluminum, copper alloy (>15% Zn), and Grade 2 titanium components.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of nineteen components per population at each unit is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service and severity of operating conditions. Opportunistic inspections continue in each period, even if the minimum number of inspections has been conducted.

Inspections are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures include requirements for items such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions.

18.1.26 Lubricating Oil Analysis

The Lubricating Oil Analysis program is an existing preventive program that ensures that loss of material and reduction of heat transfer is not occurring by maintaining the quality of the lubricating oil or hydraulic oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits. Testing activities include sampling and analysis of lubricating oil for contaminants. Oil testing that indicates the presence of water results in the initiation of corrective action that may include evaluating for in-leakage.

18.1.27 Buried and Underground Piping and Tanks

The Buried and Underground Piping and Tanks program is an existing condition monitoring program that manages loss of material, blistering, and cracking on external surfaces of components in soil or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of steel, stainless steel, copper alloys, fiberglass reinforced plastic, and concrete. Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include electrochemical verification of the effectiveness of CP, nondestructive evaluation of pipe or tank wall thicknesses, performance monitoring of fire mains, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the fuel oil system for emergency electrical power system is protected by an active CP system. Monthly periodic inspections confirm CP system availability and annual CP surveys are conducted to assess the effectiveness of the CP system. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

Five years prior to entering the subsequent period of extended operation, each unit’s buried carbon steel piping within the scope of subsequent license renewal will be cathodically protected.

This will include the buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building and the 24-inch service water piping at the Low Level Intake Structure on each unit.

Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of subsequent license renewal is not corrosive for the installed material types.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation, the sample size is increased.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the Fire Water System program (18.1.16).

18.1.28 Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is an existing condition monitoring program that manages loss of coating integrity of the internal coatings/linings of the in-scope components, exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, and air-dry environments, that can lead to loss of base material or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.

Periodic visual inspections are conducted of each coating/lining material and environment combinations applied to the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s).

For tanks, heat exchangers, and piping, all accessible surfaces are inspected. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, “Service Level I, II and II Protective Coatings Applied to Nuclear Power Plants,” including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections.

Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.

18.1.29 ASME Section XI, Subsection IWE

The ASME Section XI, Subsection IWE program is an existing condition monitoring program that manages cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness. This program is in accordance with ASME Section XI, Subsection IWE, consistent with 10 CFR 50.55a “Codes and standards,” with supplemental recommendations. The ASME Section XI, Subsection IWE program includes periodic visual, surface, and volumetric examinations, where applicable, of the metallic pressure-retaining components of the concrete containment for signs of degradation, damage, irregularities including discernible liner plate bulges, and for coated areas distress that might be indicative of degradation of the underlying metal shell or liner, and corrective actions. Acceptability of inaccessible areas of the concrete containment steel liner is evaluated when conditions found in accessible areas, indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

This program also includes surface examination for the detection of cracking of structural bolting. In addition, the program includes supplemental surface or enhanced examinations to detect cracking for specific pressure-retaining components. Containment penetrations were not analyzed for cyclic fatigue and will require surface examinations in addition to visual examinations to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading. A one-time volumetric examination of metal liner surfaces that are inaccessible from one side will be performed if triggered by plant-specific operating experience. Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side. Inspection results will be compared with prior recorded results in acceptance of components for continued service.

In conformance with 10 CFR 50.55a(g)(4)(ii), the Containment inservice inspection program will be updated during each successive 120 month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified 12 months before the start of the inspection interval.

18.1.30 ASME Section XI, Subsection IWL

The ASME Section XI, Subsection IWL program is an existing condition monitoring program that manages the following aging effects for containment concrete:

- Cracking
- Cracking; Loss of material

- Cracking and distortion
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking

Qualified inspectors identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, evaluations are performed which consider the potential for ASR development in concrete that is within the scope of the ASME Section XI, Subsection IWL program (18.1.30), the Structures Monitoring program (18.1.34), or the Inspection of Water-Control Structures Associated With Nuclear Power Plants program (18.1.35).

The design of the reinforced concrete containment does not utilize prestressing tendons. This program consists of periodic visual inspection of concrete surfaces for reinforced concrete containments for signs of degradation, assessment of damage, and corrective actions. The Subsection IWL requirements are supplemented to include quantitative acceptance criteria for concrete surfaces based on the “Evaluation Criteria” provided in Chapter 5 of ACI 349.3R-02.

In conformance with 10 CFR 50.55a(g)(4)(ii), the Containment inservice inspection program will be updated during each successive 120 month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified 12 months before the start of the inspection interval.

18.1.31 ASME Section XI, Subsection IWF

The ASME Section XI, Subsection IWF program is an existing condition monitoring program that manages loss of material, cracking, loss of preload, and loss of mechanical function for supports of Class 1, 2, and 3 components. There are no Class MC supports at SPS. This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. This program recommends additional inspections beyond the inspections required by the 10 CFR Part 50.55a ASME Section XI, Subsection IWF program. This includes a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. For high-strength bolting with an actual yield strength equal to or greater than 150 ksi in sizes greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 are performed to detect cracking in addition to the VT-3 examination. If a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

18.1.32 10 CFR Part 50, Appendix J

The 10 CFR Part 50, Appendix J program is an existing performance monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload and loss of sealing. Leakage rates through the Containment pressure boundary are monitored, including the Containment liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the Containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. Leakage rate testing is performed in accordance with the regulations and guidance provided in 10 CFR Part 50 Appendix J, Option B; Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program;" NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J;" and subject to the requirements of 10 CFR Part 54.

18.1.33 Masonry Walls

The Masonry Walls program is an existing condition monitoring program that is implemented as part of the Structures Monitoring program (18.1.34) and manages loss of material, cracking, and loss of material (spalling and scaling) that could impact the intended function of the masonry walls.

The Masonry Walls program consists of inspections, consistent with Inspection and Enforcement Bulletin (IEB) 80-11 and plant-specific monitoring proposed by Information Notice (IN) 87-67, for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained. The inspections of the masonry walls within the scope of subsequent license renewal are conducted by qualified personnel at a frequency not to exceed five years.

18.1.34 Structures Monitoring

The Structures Monitoring program is an existing condition monitoring program that monitors the condition of structures and structural supports that are within the scope of subsequent license renewal to manage the following aging effects:

- Cracking
- Cracking and distortion
- Cracking, loss of material
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Loss of material
- Loss of material, loss of form

- Loss of material, change in material properties
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

This program consists of periodic visual inspection and monitoring the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in ACI 349.3R, ACI 201.1R, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Inspections also include seismic joint fillers, elastomeric materials; and steel edge supports and steel bracings associated with masonry walls, and periodic evaluation of groundwater chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative acceptance criteria of ACI 349.3R-02, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." The inspection of structural components, including masonry walls and water-control structures, are performed at intervals not to exceed five years, except for wooden poles, which are inspected on a frequency not to exceed every eight years.

Qualified inspectors identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the Structures Monitoring program (18.1.34), the ASME Section XI, Subsection IWL program (18.1.30), or the Inspection of Water-Control Structures Associated With Nuclear Power Plants program (18.1.35).

ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel and aluminum components.

18.1.35 Inspection of Water-Control Structures Associated With Nuclear Power Plants

The Inspection of Water-Control Structures Associated with Nuclear Power Plants program is an existing condition monitoring program, which is implemented as part of the Structures Monitoring program (18.1.34), and manages the following aging effects:

- Cracking
- Cracking; blistering
- Cracking; blistering; loss of material
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material; loss of form

This program consists of inspection and surveillance of raw-water control structures associated with emergency cooling systems or flood protection, which are the Discharge Canal, Intake Canal, Discharge Tunnel and Seal Pit, High Level Intake Structure, and the Low Level Intake Structure. The program also includes structural steel and structural bolting associated with water-control structures. In general, parameters monitored are consistent with Section C.2 of Regulatory Guide 1.127, Revision 1 (March 1978), "Inspection of Water-Control Structures Associated with Nuclear Power Plants," and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. The inspections of the water control structures within the scope of subsequent licensing renewal are conducted by qualified personnel at a frequency not to exceed five years. In order to evaluate the potential of water to cause degradation of concrete, samples of groundwater are taken at intervals not to exceed five years. The water chemistry is evaluated, and should the results of water testing indicate potentially harmful levels of substances such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, inaccessible areas are assessed for aging and opportunistically inspected when excavated. Plant operating experience has not identified any structural degradation due to aggressive water chemistry.

18.1.36 Protective Coating Monitoring and Maintenance

The Protective Coating Monitoring and Maintenance program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. The program maintains and monitors the aging of Service Level 1 coatings consistent with RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear

Power Plants". The program consists of guidance for selection, application, inspection, and maintenance of protective coatings.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside Containment (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) will serve to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination, but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liner and components. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems (ECCS) suction strainers.

The program also provides controls over the amount of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the ECCS suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits to support the post-accident operability of the ECCS.

18.1.37 Electrical Insulation For Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of the accessible electrical cable and connection insulation material subject to an adverse localized environment.

The program performs a plant walkdown of in-scope structures to visually inspect for accessible cables and connections located in an adverse localized environment. If an adverse localized environment is observed, accessible electrical cables and connections installed within that environment will be visually inspected for the aging mechanisms associated with jacket surface and connection covering anomalies, such as embrittlement, discoloration, cracking, melting, swelling or surface contamination. These anomalies may indicate signs of reduced electrical insulation resistance.

A review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation will be performed.

Additionally, visual inspection findings may necessitate testing. Should testing be deemed necessary based on the unacceptable visual indications of surface anomalies, a sample of each cable and connection insulation material type found within the adverse localized environment will be tested. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the procedures.

The visual inspection frequency is based on engineering evaluation and will be performed at least once every ten years.

18.1.38 Electrical Insulation For Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program is an existing performance monitoring program that manages the aging effects of reduced electrical insulation resistance of the electrical cables and connections (cable system) insulation material subject to sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

The program applies to the containment high range radiation monitor system, the post-accident neutron monitoring system, and the excore neutron monitoring system.

The containment high range radiation monitor system cables are connected during calibration. Therefore, the calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation material aging degradation. The reviews are completed prior to the subsequent period of extended operation and at least every ten years thereafter.

The excore neutron monitoring system cables are disconnected during calibration. The program performs a proven cable test for detecting deterioration of the cable system insulation material. The test frequency is based on engineering evaluation and is performed at least once every ten years.

The post-accident neutron monitoring system cables are disconnected during calibration. The program will perform a proven cable test for detecting deterioration of the cable system insulation material. The tests will be completed prior to the subsequent period of extended operation and at least every ten years thereafter.

18.1.39 Electrical Insulation For Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of inaccessible medium-voltage cables (operating voltages of 2kV to 35kV) exposed to significant moisture.

The program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ medium-voltage power cables within the scope of subsequent license renewal exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function.

Periodic actions are taken to prevent non-EQ inaccessible medium-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. This inspection and water removal is performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding).

In-scope non-EQ inaccessible medium-voltage power cables routed through manholes and duct banks are tested to detect reduced electrical insulation resistance of the cable's insulation system. Testing that is appropriate to the application at the time of the testing is performed. Cable testing includes one or more proven testing methods (such as dielectric loss [dissipation factor (Tan-Delta)/power factor], AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis). Cable testing acceptance criteria are defined prior to each test. Cables are tested at least once every six years. More frequent testing may occur based on test results and operating experience.

There are no submarine cables or other cables designed for continuous wetting or submergence currently in the scope of this program. Future installed cables of this design would be considered for inclusion in this program.

18.1.40 Electrical Insulation For Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance leading to electrical failure of in-scope non-EQ inaccessible instrument and control cables.

This program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ instrument and control cable, within the scope of subsequent license renewal that are exposed to significant moisture, including cables designed for continuous wetting or submergence. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function.

Periodic actions will be taken to prevent inaccessible instrument and control cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. This inspection and water removal will be performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding).

Inaccessible instrument and control cables that are exposed to significant moisture, or are found to be degraded during a periodic inspection, are evaluated to determine if testing is required. If testing is required, the cables will be tested using one or more proven tests for detecting reduced insulation resistance.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

18.1.41 Electrical Insulation For Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance of inaccessible low-voltage power (operating voltage less than 2kV) cables exposed to significant moisture.

The program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ low-voltage power cables, within the scope of subsequent license renewal that are exposed to significant moisture, including cables designed for continuous wetting or submergence. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function.

Periodic actions will be taken to prevent inaccessible low-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. This inspection and water removal will be performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding).

Inaccessible low-voltage power cables that are exposed to significant moisture, or are found to be degraded during a periodic inspection, are evaluated to determine if testing is required. If testing is required, the cables will be tested using one or more proven tests for detecting reduced insulation resistance.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

18.1.42 Metal Enclosed Bus

The Metal Enclosed Bus program is an existing condition monitoring program that manages the aging effect of degradation of electrical insulating material, reduced electrical insulation resistance, cracking, and loss of continuity or increased contact resistance of the bolted connections for metal enclosed bus (MEB) and internal components. Bus enclosure assemblies (internal and external), bus bar insulation, bus bar insulating supports, and bus bar bolted connections are included.

Visual inspection of accessible metal enclosed bus internal surfaces is performed to detect age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. Accessible metal enclosed bus insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, swelling, discoloration, or surface contamination, which may indicate overheating or aging degradations. The accessible internal bus insulating supports are visually inspected for structural integrity and signs of cracks. Accessible metal enclosed bus external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion.

Accessible elastomers (e.g., gaskets, boots, and sealants) are inspected for degradation, including surface cracking, crazing, scuffing, and changes in dimensions (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening and loss of strength. A sample of accessible bolted connections is inspected for increased resistance of connection by measuring connection resistance using a micro-ohmmeter.

The first inspection, including measuring connection resistance, is completed prior to the subsequent period of extended operation and at least every twelve years thereafter for emergency buses and every ten years thereafter for non-emergency buses, with the exception of MEB associated with transfer bus F. If internal inspections of metal enclosed bus associated with either transfer bus D or E identify degradation that would result in a loss of intended function, MEB associated with transfer bus F will be scheduled for inspection and testing. An opportunistic inspection of MEB associated with transfer bus F will also be performed if a dual unit outage of at least ten days duration occurs and transfer bus F can be deenergized without a significant safety impact to the units.

18.1.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new condition monitoring program that will manage the aging effect of increased electrical resistance of electrical cable connections (metallic parts).

This program will perform a one-time inspection, on a representative sampling basis, to confirm the absence of loosening of connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation. The following factors will be considered for sampling: application (medium and low voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.).

Non-EQ electrical cable connections (metallic parts) associated with cables within the scope of subsequent license renewal will be tested prior to the subsequent period of extended operation to provide an indication of the integrity of the cables connections. The specific type of test to be performed will be determined based on the type of connection and will be a proven method for detecting loose connections, such as thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation such as heat shrink tape, sleeving, or insulating boots, etc.

Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting components under test will be included as part of the program's documentation.

A sample of cable connections within the scope of subsequent license renewal will be tested on a one-time test basis or at least once every five years if only visual inspection is used to provide an indication of the integrity of the cable connections. Depending on the findings of the one-time test, subsequent testing may have to be performed within ten years of initial testing. The first visual inspections or tests for license renewal are to be completed prior to the subsequent period of extended operation.

As an alternative to testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination may be implemented. When this alternative visual inspection is used to check cable connections, the inspection will be completed prior to the subsequent period of extended operation, and repeated at least every five years, thereafter. The basis for performing only the alternative visual inspection to monitor age-related degradation of cable connections will be documented.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

18.1.44 High-Voltage Insulators

The High-Voltage Insulators program is a new condition monitoring program that will manage loss of material and reduced electrical insulation resistance for high-voltage insulators that are credited for recovery of offsite power.

High Voltage insulator surfaces will be visually inspected to detect reduced electrical insulation resistance aging effects including cracks, foreign debris, excessive salt, dust, fog, and industrial effluent contamination. Metallic parts of the insulator will be visually inspected to detect loss of material due to mechanical wear or corrosion.

The high-voltage insulators within the scope of the High-Voltage Insulators program will be visually inspected at least once every two years initially with the frequency adjusted based on plant specific operating experience. For high-voltage insulators that are coated, the visual inspection will be performed at least once every five years.

The first inspections will be completed prior to the subsequent period of extended operation.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

18.2 SUMMARY DESCRIPTIONS OF TIME-LIMITED AGING ANALYSIS AGING MANAGEMENT PROGRAMS

18.2.1 Fatigue Monitoring

The Fatigue Monitoring program is an existing preventive program that manages cycle-based fatigue of the mechanical or structural components with a fatigue time-limited aging analysis (TLAA) or other analysis that depends on the number of occurrences and severity of transient cycles.

This program is used to accept fatigue or other types of cyclical loading TLAAs in accordance with the acceptance criterion in 10 CFR 54.21(c)(1)(iii). The aging management program monitors and tracks the number of occurrences and severity of design basis transients assessed in the applicable fatigue or cyclical loading analyses, including those in applicable cumulative usage factor (CUF) analyses, environmental-assisted fatigue analyses (CUFen analyses), maximum allowable stress range reduction/expansion stress analyses for ANSI B31.1 and ASME Code Class 2 and 3 components, ASME III fatigue waiver analyses, and cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses.

The program manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the applicable structures and components through performance of activities that monitor one or more relevant analysis parameters, such as CUF values, CUFen values, design transient cycle limit values, or predicted flaw size values. The program also sets applicable acceptance criteria (limits) on these parameters. Therefore, the program has two aspects, one to verify the continued acceptability of existing analyses through cycle counting or parameter monitoring and the other to provide periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits.

The program also implements appropriate corrective actions (e.g., reanalysis, component or structure inspections, or component or structure repair or replacement activities) when acceptance limits are approached.

18.2.2 Neutron Fluence Monitoring

The Neutron Fluence Monitoring program is an existing condition monitoring program that manages loss of fracture toughness due to neutron fluence of the reactor pressure vessel (RPV) regions for which neutron fluence is projected to exceed 1 x 10^{17} n/cm^2 (E>1MeV) during the subsequent period of extended operation to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analysis will remain within their applicable limits.

This program has two aspects, one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB).

Monitoring is performed in accordance with neutron flux determination methods and neutron fluence projection methods that are defined for the CLB in NRC-approved reports. For fluence monitoring activities that apply to components located in the beltline region of the RPVs, the monitoring methods are performed in a manner that is consistent with the monitoring methodology guidelines in Regulatory Guide (RG) 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” Neutron fluence monitoring methods that are applied to RPV locations outside of the beltline region of the RPVs were justified and are consistent with NRC-approved methodology.

This program's results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for RPV components. This includes but is not limited to the neutron fluence inputs for the RPV upper-shelf energy analyses and equivalent margin analyses, pressure-temperature analyses, and low temperature overpressure protection (LTOP) that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements, and safety analyses that are performed to demonstrate adequate protection of the RPVs against the consequences of pressurized thermal shock (PTS) events, as required by 10 CFR 50.61 and applicable to the CLB. Comparisons to the neutron fluence inputs for other analyses (as applicable to the CLB) includes those for RT_{NDT}.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the Reactor Vessel Material Surveillance program (18.1.19) provides inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G; 10 CFR 50.55a; and the PTS requirements in 10 CFR 50.61, as applicable for the CLB.

18.2.3 Environmental Qualification of Electric Equipment

The Environmental Qualification of Electrical Equipment program manages equipment thermal, radiation, and cyclical aging through the use of aging evaluations based on qualification methods given in 10 CFR 50.49. This program implements the EQ requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform applicable safety functions in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

As required by 10 CFR 50.49, environmentally qualified equipment not qualified for the current license term is refurbished or replaced, or has its qualified life extended through reanalysis or ongoing qualification prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for environmentally qualified equipment that specify a qualified life of at least 40 to 60 years are time-limited aging analyses (TLAAs) for subsequent license renewal.

The Environmental Qualification of Electrical Equipment program is consistent with the guidance of 10 CFR 50.49; Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment”; “Guidelines for Evaluation of Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors” (DOR Guidelines); and IEEE Standard 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

Reanalysis of an aging evaluation to extend the qualification of equipment qualified under the program requirements of 10 CFR 50.49(e) is performed as part of the EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The identification of excess conservatism in electrical equipment service conditions (for example, temperature, radiation, and cycles) used in the prior aging evaluation is the primary method used for a reanalysis. A reanalysis demonstrates that adequate margin is maintained consistent with the original analysis in accordance with 10 CFR 50.49 requiring certain margins and accounting for the unquantified uncertainties established in the EQ aging evaluation of the equipment. Reanalysis of an aging evaluation can be used to extend the environmental qualification of the equipment. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or requalified prior to exceeding the current qualified life.

When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g., extending qualified life) of environmentally qualified equipment, the use of on-going qualification techniques including condition monitoring or condition based methodologies may be implemented. Ongoing qualification is an alternative means to provide reasonable assurance that equipment environmental qualification is maintained for the subsequent period of extended operation. Ongoing qualification of electric equipment within the scope of the EQ program involves the inspection, observation, measurement, or trending of one or more indicators, which can be correlated to the condition or functional performance of the environmentally qualified equipment.

18.3 EVALUATION SUMMARIES OF TIME-LIMITED AGING ANALYSES

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of Time-Limited Aging Analyses (TLAAs) for the subsequent period of extended operation be provided. The following TLAAs, as defined in 10 CFR 54.3, have been identified and evaluated to meet this requirement.

18.3.1 Identification of Time-Limited Aging Analyses

10 CFR 54.21(c)(2) requires that the application for a renewed license include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based upon TLAAs as defined in 10 CFR 54.3. It also requires an evaluation that justifies the continuation of these exemptions for the subsequent period of extended operation. There were no exemptions to 10 CFR 50.12 identified that are currently in effect that are based upon or are associated with a TLAA.

The following TLAAs have been identified and evaluated to meet 10 CFR 54.21(c) requirements. Summaries of the TLAAs applicable to the subsequent period of extended operation are included in the following sections:

- Reactor Vessel Neutron Embrittlement Analysis (Section 18.3.2)
- Metal Fatigue (Section 18.3.3)
- Environmental Qualification of Electric Equipment (Section 18.3.4)
- Concrete Containment Tendon Prestress (Section 18.3.5)
- Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis (Section 18.3.6)
- Other Plant-Specific Time-Limited Aging Analyses (Section 18.3.7)

18.3.2 Reactor Vessel Neutron Embrittlement Analyses

10 CFR 50.60 requires that all light water reactors meet the fracture toughness, P-T limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The Reactor Head Closure Stud Bolting program is described in Section 18.1.19. The ferritic materials of the reactor pressure vessel (RPV) are subject to embrittlement due to high energy ($E > 1.0$ MeV) neutron exposure. Embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness

associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). Since these neutron embrittlement analyses are calculated based on plant life, they are identified as TLAAs. The following RPV neutron embrittlement TLAAs have been identified and evaluated to meet 10 CFR 54.21(c) requirements:

- Neutron Fluence Projections
- Upper-Shelf Energy
- Pressurized Thermal Shock
- Adjusted Reference Temperature
- Pressure Temperature Limits
- Low Temperature Overpressure Protection

18.3.2.1 Neutron Fluence Projections

Updated neutron fluence evaluations were performed and documented in WCAP-18028-NP, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Power Station Units 1 & 2.” RPV beltline and extended beltline fast neutron fluences (E > 1.0 MeV) at the end of 80 years of operation were calculated for Units 1 and 2. The analyses methodologies used to calculate the Units 1 and 2 RPV fluences satisfy the guidance set forth in Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” These methodologies have been approved by the NRC and are described in detail in WCAP-14040, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” and are documented in UFSAR Section 4.1.7.3, “Calculation of Integrated Fast Neutron (E Greater than 1.0 MeV) Flux at the Irradiation Samples.” The fluence analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.2.2 Upper-Shelf Energy

Appendix G of 10 CFR 50, Paragraph IV.A.1.a, indicates that reactor pressure vessel (RPV) beltline materials must have Charpy upper-shelf energy of no less than 75 ft-lb initially, and must maintain Charpy upper-shelf energy throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code, “Fracture Toughness Criteria for Protection Against Failure”. For materials outside the beltline, a minimum value of 30 ft-lbs at 10 °F was specified by ASTM E208 at the time of the initial design of Units 1 and 2. The upper shelf energy (USE) analyses for the ferritic steel components (i.e., RPV shell plates or forgings, nozzle plates or forgings, and associated pressure retaining welds) in the beltline region of the RPV have been updated based on component neutron fluence values that have been projected to the end of the subsequent period of extended operation and the current RPV surveillance test data for the facility. Based on WCAP-18242-NP, Surry Power Station Units 1 and 2 Time Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal, the materials that exceeded the 1.0×10^{17} n/cm^2 (E > 1.0 MeV) threshold at 68 EFPY are considered to be the Units 1 and 2 extended beltline materials and were evaluated to determine their impact on the subsequent period of extended operation. The forgings and welds corresponding to the Units 1 and 2 Inlet Nozzles 1, Inlet Nozzles 3, and Outlet Nozzles 3 are predicted to experience neutron fluence greater than 1.0×10^{17} n/cm^2 at the end of the period of extended operation. However, for conservatism all of the Units 1 and 2 inlet and outlet nozzle materials are considered part of the extended beltline.

For Unit 1, the limiting USE value at 68 EFPY is 32 ft-lb; this value corresponds to the Intermediate to Lower Shell Circumferential Weld (Heat # 72445). For Unit 2, the limiting USE value at 68 EFPY is 41 ft-lb; this value corresponds to the Upper to Intermediate Shell Circumferential Weld (Heat # 4275).

The NRC has previously approved the use of the equivalent margins analysis (EMA) BAW-2494, Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Surry Power Station Units 1 and 2 for Extended Life through 48 Effective Full Power Years to qualify all of the materials currently projected to drop below 50 ft-lb USE at 68 EFPY. The EMAs for these materials are updated for the subsequent period of extended operation under ANP-3679NP, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80 Years” and ANP-3680NP, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80 Years” The updated EMA is based upon the provisions outlined in NRC Regulatory Guide 1.161 and Section XI of the ASME Code, Appendix K. The EMAs were submitted with the subsequent license renewal application.

The following Units 1 and 2 materials are addressed by EMAs in ANP-3679NP and ANP-3680NP for the subsequent period of extended operation:

Unit 1:

- Upper to Intermediate Shell Circumferential Weld, Heat # 25017 (J726)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 8T1554
- Intermediate to Lower Shell Circumferential Weld, Heat # 72445
- Lower Shell Longitudinal Weld L1, Heat # 8T1554
- Lower Shell Longitudinal Weld L2, Heat # 299L44
- Inlet Nozzle to Shell Welds, Heat # 299L44 and # 8T1762; (Projected USE > 50 ft-lbs at 68 EFPY)

- Outlet Nozzle to Shell Welds, Heat # 8T1762 and # 8T1554B; (Projected USE > 50 ft-lbs at 68 EFPY)

Unit 2:

- Upper to Intermediate Shell Circumferential Weld, Heat # 4275 (J737)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 72445
- Intermediate Shell Longitudinal Weld L4, Heat # 8T1762
- Intermediate to Lower Shell Circumferential Weld, Heat # 0227
- Lower Shell Longitudinal Weld L1 and L2, Heat # 8T1762
- Inlet Nozzle to Shell Welds, Heat # 8T1762; (Projected USE not projected > 50 ft-lbs at 68 EFPY)
- Outlet Nozzle to Shell Welds, Rotterdam Weld; (Projected USE > 50 ft-lbs at 68 EFPY)

Note that as a conservative measure, an EMA has been completed for Units 1 and 2 Inlet and Outlet Nozzle to Shell Welds even though these materials are not projected to drop below 50 ft-lbs through 68 EFPY. The inlet and outlet nozzle welds are the only materials included in ANP-3679NP and ANP-3680NP that were not previously addressed by EMA. The EMA is applicable to Units 1 and 2 nozzle to shell welds which exceed the fluence criterion of 1.0×10^{17} n/cm^2 before 68 EFPY. These materials include those listed below.

- Unit 1 Outlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 3 to Upper Shell Weld
- Unit 2 Outlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 3 to Upper Shell Weld

For Unit 1, the limiting USE value for materials not requiring an EMA at 68 EFPY is 54 ft-lb; this value corresponds to the Inlet Nozzle to Upper Shell Welds (Heat # 299L44). For Unit 2, the limiting USE value for materials not requiring an EMA at 68 EFPY is also 54 ft-lb; this value corresponds to the Outlet Nozzle to Upper Shell Welds (Rotterdam). Except for the materials listed above, all of the beltline and extended beltline materials in Units 1 and 2 RPVs are projected to remain above the USE screening criterion value of 50 ft-lb (per 10 CFR 50, Appendix G) through the subsequent period of extended operation (68 EFPY).

The USE TLAA has been projected to the end of the subsequent period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.2.3 **Pressurized Thermal Shock**

10 CFR 50.61(b)(1) provides rules for protection against pressurized thermal shock (PTS) events for pressurized water reactors and requires the reference temperature RTPTS for reactor pressure vessel (RPV) beltline materials to be less than the PTS screening criteria at the expiration date of the operating license unless otherwise approved by the NRC. All of the beltline and extended beltline materials in the Units 1 and 2 RPV are below the RTPTS screening criteria values of 270 °F for base metal and/or longitudinal welds, and 300 °F for circumferentially oriented welds through 68 EFPY. The PTS analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.2.4 **Adjusted Reference Temperature**

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. 10 CFR 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. Regulatory Guide 1.99 provides the methodology for determining the ART of the limiting material. RTNDT was evaluated in accordance with PWROG-16045-NP. The limiting ART values at 48 EFPY and 68 EFPY are less than the limiting ART values used to develop the existing P-T limit curves. The ART analyses have been projected to the end of the period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.2.5 **Pressure-Temperature Limits**

10 CFR 50 Appendix G requires that the RPV be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RPV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RPV fluence.

According to NUREG-2192, Section 4.2.2.1.4, the P-T limits for the subsequent period of extended operation need not be submitted as part of the subsequent license renewal application since the P-T limits are required to be updated through the 10 CFR 50.90, “Application for Amendment of License, Construction Permit, or Early Site Permit,” licensing process when necessary for P-T limits that are located in the Technical Specifications. The P-T limit curves for normal heatup and cooldown of the primary reactor coolant system for Units 1 and 2 were previously developed in WCAP-14177.

The Reactor Vessel Material Surveillance program (18.1.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the current terms of applicability for Units 1 and 2. Since the P-T limits will be updated through 10 CFR 50.90 at a later, appropriate date, the effects of aging on the intended function(s) of the RPVs will be adequately managed for the period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

18.3.2.6 **Low Temperature Overpressure Protection**

The Units 1 and 2 low temperature overpressure protection (LTOP) system is required by Technical Specification Limited Condition for Operation 3.1.G. Two pressurizer power operated relief valves (PORV) are used to provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the reactor coolant system pressure from exceeding the pressure temperature limit curves based on 10 CFR 50, Appendix G.

The LTOP enabling temperature has been determined for 68 EFPY. Using Code Case N-514, the LTOP enabling temperature is 283°F. Using Code Case N-641, the LTOP enabling temperature can be either 273°F or 262°F. The Surry Technical Specification 3.1.G.1.c (4) specifies an arming temperature of 350°F which is conservative and remains valid for the subsequent period of extended opeation.

In WCAP-18242-NP, "Surry Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal," the maximum allowable Low Temperature Overpressure Protection System (LTOPS) pressurizer PORV setpoint was calculated to be 399.6 psig for the subsequent period of extended operation. The calculation was performed in accordance with the WCAP-14040-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit," methodology using critical LTOPS input parameters and the limiting axial flaw steady state Appendix G limits calculated for 68 EFPY. The evaluation showed that the current Technical Specification value of ≤ 390.0 psig is bounding and will remain valid for the subsequent period of extended operation.

The LTOP system licensing and design basis analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.3 Metal Fatigue

Fatigue analyses are required on components designed to ASME Code, Section III, Class 1. Also, certain other codes such as ASME Code, Section III, Class 2 and 3, USAS (ANSI) B31.1, and ASME Code, Section VIII, Division 2, may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. NUREG-2192 also provides examples of components that are likely to have fatigue TLAAs within the current licensing basis (CLB) that would require evaluation for the subsequent period of extended operation. Searches were performed to identify these and any other potential fatigue TLAAs within the current licensing bases for Units 1 and 2. Each of the potential TLAAs were evaluated against the six

TLAA screening criteria specified in 10 CFR 54.3. Those that were identified as fatigue TLAAs are evaluated in the following Subsections:

- Transient Cycle Projections for 80 years (Section 18.3.3.1)
- ASME Code, Section III, Class 1 Fatigue Analyses (Section 18.3.3.2)
- ANSI B31.1 Allowable Stress Analyses (Section 18.3.3.3)
- Environmental- Assisted Fatigue (Section 18.3.3.4)
- Reactor Vessel Internals Fatigue Analyses (Section 18.3.3.5)

18.3.3.1 **Transient Cycle Projections for 80 years**

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients. UFSAR Table 4.1-8 and Section 18.4.1 provides a listing of design transients and associated design cycles. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. The existing fatigue analyses are based upon the original number of design cycles (40 years) and are postulated to bound 60 years of service. Since the fatigue analyses are based upon a number of cycles postulated to bound sixty years of service for the current license basis, these analyses constitute a TLAA.

Baseline cycle counts were projected to an 80-year operating life based on the actual accumulation history over the 10-year period from June 30, 2006 to June 30, 2016. Since most nuclear power plants, including SPS Units 1 and 2, have experienced a significant declining trend in accumulation of transients over time, transient projections based on recent operating experience provide an appropriate basis for future projections. Therefore, each monitored design transient was evaluated to determine if the recent 10-year trend had a consistent cycle accumulation rate. The 10-year rate was used to extrapolate the projected number of future occurrences beginning June 30, 2016 and ending at 80 years of plant operation. The end of 80-year life is June 2052 for Unit 1 and March 2053 for Unit 2. The projected cycles for 80 years of plant operation were less than the 40-year design cycles (CLB cycles) used in the fatigue analyses. Therefore, the fatigue analyses for ASME Code, Section III components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the ASME Code, Section III fatigue analyses, the Fatigue Monitoring program (Section 18.2.1) will track cycles for significant fatigue transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits. A Condition Report will be initiated based upon an administrative limit of 90% of the fatigue cycles.

18.3.3.2 **ASME Code, Section III, Class I Fatigue Analyses**

Fatigue analyses are performed per ASME Code, Section III. Each analysis is required to demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the Code design limit 1.0 when the component is exposed to all postulated transients.

The following ASME Code, Section III components were assessed for impact on fatigue:

- Control Rod Drive Mechanism (CRDM)
- Pressurizer
- Reactor Coolant Pump
- Reactor Vessel
- Steam Generator
- Pressurizer Surge Line
- Charging and Accumulator Piping

In addition, a detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements per ASME Code, Section III. These fatigue waivers depend on the numbers of anticipated transients over the life of the plant and therefore constitute TLAAs.

The 40-year design cycles (CLB cycles) were postulated to bound 80 years of plant operations. Therefore, the fatigue analyses and fatigue waivers remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the fatigue analyses and fatigue waivers, the Fatigue Monitoring program (Section 18.2.1) will track cycles for significant fatigue transients listed in the UFSAR, Table 4.1-8 and Section 18.4.1, and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

The effects of fatigue on the intended function(s) of ASME Code, Section III components will be adequately managed by the Fatigue Monitoring program (Section 18.2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.3.3.3 **ANSI B31.1 Allowable Stress Analyses**

The reactor coolant system's primary loop piping and the balance-of-plant piping in scope for subsequent license renewal are analyzed to the requirements of ANSI B31.1, "Power Piping." There are two aspects of note that pertain to fatigue for the ANSI B31.1 piping. The first aspect is discussed below and is related to the design of the piping which does not utilize fatigue usage factors. The second aspect deals with the concern of environmental effect which is discussed in Section 18.3.3.4.

For piping systems designed in accordance with ANSI B31.1, explicit analyses of cumulative fatigue usage are not required. Instead, cyclic loading is considered in a simplified manner in the design process. Allowable thermal stresses are reduced using a stress range reduction factor based on the number of anticipated thermal cycles expected during the component operating lifetime. Stress range reduction factors are specified in ANSI B31.1, Table 102.3.2(c). No reduction of allowable stresses is required for piping that is subjected to less than 7,000 equivalent full temperature cycles during plant service. The stress range reduction factor for higher numbers of fatigue cycles is less than 1.0 and is gradually reduced until a range of 100,000 cycles is reached. For piping anticipated to experience 100,000 or more equivalent full temperature cycles, the allowable stress range would be reduced to half of the maximum nominal allowable stress. The evaluations for required stress reduction factors are implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component, therefore they are TLAAs requiring evaluation for the subsequent period of extended operation.

ANSI B31.1 systems are generally subject to continuous steady state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or during periodic testing. Portions of piping systems designed in accordance with ANSI B31.1 requirements that are attached to the reactor coolant system or other power cycle related systems are subject to a similar number or fewer cycles as the reactor coolant system. These include generator nitrogen, main steam, blowdown, feedwater, condensate, chemical and volume control, extraction steam, residual heat removal, and safety injection. Portions of some of these systems are normally isolated from the normal power cycle and would experience fewer cycles than those portions at the system boundary. For example, residual heat removal system cycles twice per shutdown/start up and therefore has fewer cycles than the residual heat removal system piping at the boundary with the reactor coolant system. The expected transients for these systems are much less than 7,000 cycles for 80 years of plant operation.

Portions of the following systems, designed in accordance with ANSI B31.1 requirements, are affected by thermal and pressure transients that are different than the reactor coolant and power cycles discussed above: auxiliary steam, boron recovery, containment vacuum and leakage monitoring, emergency diesel generator (engine exhaust), alternate AC diesel generator (engine exhaust), security diesel (engine exhaust), fire protection (fire pump diesel exhaust), heating steam, recirculation spray, sampling system, and steam drains. The basis for cycle projections have been reviewed for these systems to validate that the projected cycles for 80 years of operation remains less than 7,000 cycles. The number of cycles for each of these piping systems is projected to be less than 7,000 for 80 years of plant operation.

The ANSI B31.1 allowable stress analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21 (c)(1)(i).

18.3.3.4 **Environmental- Assisted Fatigue**

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on cumulative usage factor (CUF) must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260.

Additional limiting locations were identified through an environmental fatigue screening evaluation. The environmentally-assisted fatigue (EAF) screening evaluation reviewed the CLB fatigue evaluations for all ASME Code, Section III reactor coolant pressure boundary components and ANSI B31.1 piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

The sentinel locations are listed below:

- CRDM head adapters (J-groove weld) - replacement RV closure heads
- RV outlet nozzles and support pads (NUREG/CR-6260 location)
- RV inlet nozzles (NUREG/CR-6260 location)
- RV bottom head-to-shell juncture (NUREG/CR-6260 location)
- CRDM upper latch housing and rod travel housing – upper latch housing
- CRDM upper joint – Canopy
- Pressurizer spray nozzle
- Pressurizer spray nozzle – Piping
- Pressurizer
- Upper shell
- Pressurizer Safety and Relief nozzles
- Pressurizer lower head at heater penetration
- Hot leg surge nozzle - bounding location (NUREG/CR-6260 location)
- Pressurizer surge piping
- Pressurizer surge nozzle to safe end weld
- Charging nozzle (NUREG/CR-6260 location)
- Safety injection nozzle (NUREG/CR-6260 location)
- Residual heat removal piping (NUREG/CR-6260 location)
- Steam generator tubes
- Accumulator piping NUREG/CR-6260 location)

For sentinel ASME Code, Section III components with environmentally-assisted fatigue usage (CUF_{en}) greater than 1.0, ASME Code, Section III, NB-3200 calculations were prepared to remove conservatisms used in the analysis of record, thereby reducing the CUF_{en} to less than 1.0. The effects of fatigue on the intended functions of these ASME Code, Section III components will be managed by the Fatigue Monitoring program (Section 18.2.1) through the use of cycle counting.

For sentinel piping locations, Dominion has elected to manage the effects of fatigue by application of the ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD program (Section 18.1.1) during the subsequent period of extended operation based on results of flaw tolerance evaluation conducted per the guidance of ASME Code, Section XI, Non-mandatory Appendix L. NUREG-2192 permits inspections as a management method for fatigue as long as a flaw tolerance evaluation is performed to determine the acceptable time between inspections. The ASME Code, Section XI, Appendix L crack growth evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location. For a postulated initial flaw, crack growth is simulated until the flaw has reached the allowable flaw depth or the end of the subsequent period of extended operation, whichever comes first.

In-service inspections of the Appendix L piping will be performed at a 10-year inspection frequency. Each weld in the inspection population will be ultrasonically inspected once prior to turning on the clock for the re-inspection schedule associated with the Appendix L evaluations. Going forward after the first ultrasonic inspection, one weld in each of the six groups will be ultrasonically inspected every ten years.

Fatigue of the steam generator tubes will be managed by the Steam Generators program (Section 18.1.10).

The effects of fatigue on the intended functions of ASME Code, Section III components and piping that contact reactor coolant will be managed by the Fatigue Monitoring program (Section 18.2.1), the ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD program (Section 18.1.1) and the Steam Generators program (Section 18.1.10) through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.3.3.5 **Reactor Vessel Internals Fatigue Analyses**

The RV internals were designed before ASME Code, Section III, Division 1, Subsection NG was established. Therefore, no CUF values were calculated as part of the original RV internals design. However, as part of engineering evaluations to support Units 1 and 2 operations at MUR power uprate conditions, updated structural evaluations were performed for the upper and lower core plates to demonstrate that they would maintain their structural integrity at proposed power uprate conditions. The lower and upper core plates are not part of the reactor coolant system pressure boundary. As part of the structural evaluations, fatigue analyses of the upper and lower core plates were performed to the 1989 edition of ASME Code, Section III, Division 1, Subsection NG. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The analysis of record fatigue CUF results are less than 1.0.

The 40-year design cycles (CLB cycles) were postulated to bound 80 years of plant operations. Therefore, the reactor vessel internals fatigue analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.3.4 Environmental Qualification of Electric Equipment

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs). The NRC nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49 require that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments is qualified to perform applicable safety functions in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a loss-of-coolant accident (LOCA), high energy line break (HELB) or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The Environmental Qualification of Electric Equipment program (18.2.3) will manage the effects of aging for EQ equipment through the subsequent period of extended operation in accordance with 10 CFR 50.49(c)(1)(iii). The program meets the requirements of 10 CFR 50.49 for the applicable electrical equipment important to safety. Reanalysis of an aging evaluation to extend the qualifications of equipment is performed on a routine basis as part of the EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, ongoing qualification, and corrective actions if acceptance criteria are not met.

If the qualification cannot be extended by reanalysis, the equipment must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the equipment if the reanalysis is unsuccessful.

The EQ program was evaluated against the DOR Guidelines and the basis for equipment qualification is Inspection and Enforcement Bulletin (IEB) 79-01B (IEB 79-01B), "Environmental Qualification of Class 1E Equipment," and IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," as codified by 10 CFR 50.49.

The Environmental Qualification of Electrical Equipment program ensures that the aging effects will be managed and that EQ equipment will continue to perform its intended function for the subsequent period of extended operation. Aging effects addressed by the EQ program will therefore be managed for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

Accessible passive EQ electrical equipment within the scope of subsequent license renewal will be inspected at least once every ten years to identify EQ electrical equipment subjected to an adverse localized environment with the first inspection performed prior to the subsequent period of extended operation.

18.3.5 Concrete Containment Tendon Prestress

Not applicable

18.3.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis

18.3.6.1 Containment Liner Plate

The accumulated fatigue effects of all applicable liner loading conditions are evaluated based on cycles of operating pressure variations, cycles of operating temperature variations, and design earthquake cycles. The anticipated operating pressure variations were extrapolated for 80 years of operation and determined to be acceptable. The number of design cycles was conservatively increased to account for the subsequent period of extended operation. Therefore, the Containment liner is adequate for an 80-year operating period as currently designed. The analyses associated with the Containment liner plate have been revised and projected to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.6.2 Metal Containments

Not applicable

18.3.6.3 Containment Penetrations Fatigue Analysis

There are no TLAAs for Containment penetrations. The penetrations are designed for a one-time load, which is equal to the collapse loads of the pipe. The stresses due to the normal operating conditions are within the endurance limit. Therefore, the penetrations will not fail for a large number of operating cycles. No time-limited aging analysis has been performed for the penetrations.

18.3.7 Other Plant-Specific Time-Limited Aging Analyses

18.3.7.1 Crane Load Cycle Limits

The design standard number of full-capacity lifts far exceeds the number expected of each machine for a 80-year life, even with a significant number of unforeseen lifts. The lifting machine designs therefore remain valid for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

18.3.7.2 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis

Fatigue crack initiation and growth in reactor coolant pump (RCP) flywheels was evaluated for the subsequent period of extended operation and documented in PWROG-17011-NP, “Update for Subsequent License Renewal: WCAP-14535A, “Topical Report on Reactor Coolant Pump

Flywheel Inspection Elimination," and WCAP-15666-A, "Extension of Reactor Coolant Pump Motor Flywheel Examination," Revision 0," which confirms that the analysis of WCAP-14535A and WCAP-15666-A remains appropriate. The fatigue crack growth calculations assumed 6000 cycles of RCP start/stop for 80 years of plant life which bounds the projected cycle count of 1158. The RCP fatigue analysis remains valid for the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

18.3.7.3 **Leak-Before-Break**

10 CFR 50 General Design Criterion 4 allows use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in PWRs. WCAP-15550-NP, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation," demonstrated compliance with leak-before-break (LBB) technology for the reactor coolant system piping for an 80-year plant life based on a plant specific analysis that showed all LBB conditions and margins are satisfied. It is therefore concluded that dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis. The LBB analysis has been projected to the end of the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

The Leak-Before-Break (eLBB) methodology currently applied to the Reactor Coolant System main piping was extended to the Reactor Coolant System branch piping listed below for the 80 year extended period of plant operations. Details related to the RCS branch line Leak-Before-Break analysis and associated references are included in UFSAR Section 15.6.2.

1. Pressurizer Surge Line
2. Residual Heat Removal Line
3. Accumulator Line
4. Loop Bypass Line
5. Safety Injection Line

18.3.7.4 **Spent Fuel Pool Liner Fatigue Analysis**

A design calculation has been identified which documents that the spent fuel pool liner design meets general industry criteria. A revised calculation includes a fatigue analysis based on the number of thermal cycles corresponding to an 80-year plant operating term. The thermal stresses in the spent fuel pool liner due to conservatively assumed temperature gradients and thermal cycles during an 80-year plant operating term satisfy ASME Code fatigue criteria. Therefore, the revised calculations are projected through the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.7.5 **Piping Subsurface Flaw Evaluations**

Piping subsurface flaws were detected during original plant construction. Flaw tolerance conclusions of the piping subsurface flaws evaluations have been projected to the end of the subsequent period of extended operation. The piping flaw TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.7.6 **Reactor Coolant Pump Code Case N-481**

ASME Code Case N-481 allows the replacement of volumetric examinations of primary loop pump casings with fracture mechanics-based integrity evaluations supplemented by specific visual examinations. The fracture mechanics integrity assessment in PWROG-17033 -NP, "Update for Subsequent License Renewal: WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems," Revision 0," which updated the analysis in WCAP-13045, demonstrated that the visual inspections, in lieu of volumetric inspections, for pump casings remain valid for an 80-year life and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

18.3.7.7 **Cracking Associated With Weld Deposited Cladding**

Reactor vessel underclad cracking involves cracks in base metal forgings immediately beneath austenitic stainless steel cladding which are created as a result of the weld-deposited cladding process. PWROG-17031-NP, "Update for Subsequent License Renewal: WCAP-15338-A, "A Review of Cracking Associated with Weld Deposited Cracking in Operating PWR Plants," Revision 0," updated the 60-year fatigue crack growth analysis in WCAP-15338-A and confirmed the analysis remains appropriate for 80 years of operation. The crack growth analysis has been projected to the end of the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.7.8 **Steam Generator Tube High Cycle Fatigue Evaluation**

WCAP-18379-P, "Surry Units 1 and 2 Steam Generator U-Bend Tube Vibration and Fatigue Assessment" evaluated the SG tubes that are unsupported by an AVB which is contrary to the design requirements, or tubes that are subject to significant flow peaking due to non-uniform insertion of the AVBs, to determine if they are subject to possible fatigue related failure during the planed 80 years of plant life.

The new fatigue analysis demonstrates that all unsupported tubes are acceptable without remediation through 80 years. This evaluation is projected through the subsequent period of extended operation and this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.7.9 **Steam Generator Tube Wear Evaluation**

WCAP-18341-P, "Resolution of Surry Power Station Units 1 & 2 Time-Limited Aging Analyses for Subsequent License Renewal," shows that for the increase the operating term from 60 years to 80 years, the calculated tube wear remains acceptable. The steam generator tube wear will be managed by the Steam Generators program (18.1.10) using the existing steam generator eddy current inspection consistent with NEI 97-06, “Steam Generator Program Guidelines”

The wear evaluation for operation under MUR power uprate conditions demonstrates wear of the steam generator tubes will be acceptable through 80 years of plant operation. The steam generator tube wear will be managed by the Steam Generators program (18.1.10) in accordance with 10 CFR 54.21(c)(iii).

18.4 TLAA SUPPORTING ACTIVITIES

18.4.1 Transient Cycle Counting

During normal, upset, and test conditions; reactor coolant system pressure boundary components are subjected to transient temperatures, pressures, and flows, resulting in cyclic changes in internal stresses in the equipment. The cyclic changes in internal stresses cause metal fatigue. Class 1 reactor coolant system components have been designed to withstand a number of design transients without experiencing fatigue failures during their operating life. The purpose of the Transient Cycle Counting is to record the number of normal, upset, and test events, and their sequence that the station experiences during operation. Design transients are counted to provide reasonable assurance that plant operation does not occur outside the design assumptions.

The Transient Cycle Counting activities are applicable to the reactor coolant system pressure boundary components for which the design analysis assumes a specific number of design transients. A summary of reactor coolant system design transients for which transient cycle counting is performed is listed below:

- Heatups/Cooldowns < 100°F/Hr.
- Step load increase/decrease of 10%
- Large load reduction of 50%
- Loss of load > 15%
- Loss of AC power
- Loss of flow in one loop
- Full power reactor trip
- Inadvertent auxiliary pressurizer spray

The aging effect that is managed by counting transient cycles is cracking due to metal fatigue. The Transient Cycle Counting activities monitor transient cycles that have been experienced by each unit and compare the actual number of cycles to a design assumption. Any concerns related to fatigue are mitigated, as long as the number and magnitude of transient cycles are less than the design assumptions. Approaching a design limit may indicate a situation that is adverse to quality, and would initiate the Corrective Action System. Subsequently, an engineering analysis will determine the design margin remaining, taking credit for the actual magnitude of transients and their sequence to confirm that the allowable factor has not been exceeded. If warranted, component repair or replacement would be initiated.

18.5 SUBSEQUENT LICENSE RENEWAL COMMITMENTS

Table 18-1
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program	The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspections be performed for welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix L for the following auxiliary lines: • Safety injection • Residual heat removal • Spray • Charging • Accumulator • Surge	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2
2	Water Chemistry program	The Water Chemistry program is an existing preventive program that is credited.	Ongoing	SLRA, Appendix A, Table A4.0-1	2
3	Reactor Head Closure Stud Bolting program	The Reactor Head Closure Stud Bolting program is an existing condition monitoring program that will be enhanced as follows: 1. Procurement documents for reactor head closure studs will be revised to incorporate guidance from RG 1.65, Revision 1 and NUREG-2191, Section XI.M3, to add a limit for the maximum measured yield strength of 150 ksi and a limit for maximum tensile strength of 170 ksi. 2. Procedures will be revised to require the performance of a one-time visual inspection of the bottom plates in Unit 2 vessel flange closure stud holes #36 and #37 to confirm that no corrosion, cracking, or degradation is occurring.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	
4	Boric Acid Corrosion program	The Boric Acid Corrosion program is an existing condition monitoring program that is credited.	Ongoing	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
5	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components program	The Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components program is an existing condition monitoring program that is credited.	Ongoing	SLRA, Appendix A, Table A4.0-1	2
6	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program	The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program is an existing condition monitoring program that is credited.	Ongoing	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
7	PWR Vessel Internals program	The PWR Vessel Internals program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised for each reload to summarize the average power density, the heat generation figure-of-merit, and the dimensional parameter for the distance between the active fuel and the upper core plate. 2. Procedures will be revised to require the visual inspection (EVT-1) of the control rod guide tube (CRGT) lower flange weld to require that the inspection include 100% of the outer CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal. 3. Procedures will be revised to require the visual inspection (VT-3) of the accessible surfaces for the control rod guide tube support pins and support pin nuts for Unit 1 only (plant-specific component). 4. Procedures will be revised to require the addition of a note indicating that a bolting inspection can be credited only if at least 75% of the total bolt population is examined. 5. Procedures will be revised to require visual inspection (VT-3) for 100% of the baffle-edge bolts that are accessible from the core side. 6. Procedures will be revised to require volumetric (UT) examinations for 100% of accessible baffle-former bolts (including corner bolts) at least every 10 years. MRP-2017-009 states that baseline volumetric (UT) examinations shall be performed no later than 30 EFPY for NSAL 16-1 Tier 2 plants, including the Surry units. The guidance further states that initial baseline UT exams performed prior to 1/1/2018 are acceptable. Examinations were performed in 2010 for Unit 1 and in 2011 for Unit 2. For the Surry units with the down-flow configuration that have <3% indications and no clustering, subsequent UT examinations are performed on a 10-year interval.	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 First Annual Amendment and Supplement to SLRA: Change Notice 4 Supplement to SLRA: Change Notice 7	2,10, 13

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
7 cont'd		7. Procedures will be revised to address expansion criteria when degradation occurs for clusters of baffle-former bolts. MRP 2018-002 identifies expansion criteria as a Needed requirement (per NEI 03-08) to include one-time visual (VT-3) examination of barrel-former bolts if large clusters of baffle-former bolts are found during the initial volumetric (UT) examination. Confirmation that one or more large clusters of baffle-former bolts with unacceptable indications are detected by the UT inspection of the baffle-former bolts shall require a visual (VT-3) inspection of the accessible barrel-former bolts adjacent to the large cluster of baffle-former bolt indications within three refueling cycles. A large cluster is defined (MRP 2018-002, Item 3.b) as any group of adjacent baffle-former bolts at least 3 rows high by at least 10 columns wide, or at least 4 rows high by at least 6 columns wide where 80% or greater of the baffle-former bolts have unacceptable UT indications or are visibly degraded.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
7 (cont'd)		The barrel-former bolts adjacent to the cluster include: • Barrel-former bolts in the same area as the cluster of baffle-former bolts with indications if that area is projected radially onto the core barrel. • Barrel-former bolts on the two rows above and the two rows below the projected area. • Barrel-former bolts on each of the two columns of bolts that are circumferentially adjacent to the projected area. Confirmation that more than 5% of the lower support column bolts actually examined contain unacceptable UT indications shall require UT inspection of the accessible barrel-former bolts within three refueling cycles of identifying lower support column bolts with unacceptable UT indications. 8. Procedures will be revised to require visual examinations (EVT-1) for 100% of one side (ID or OD) of the circumference for the core barrel upper flange weld, and 3/4" of adjacent base metal (minimum 50% examination coverage) (Primary component) 9. Procedures will be revised to require visual examinations (EVT-1) for 100% of the OD surface of the core barrel lower flange weld and 3/4" adjacent base metal (minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld). (Expansion component)			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
7 (cont'd)		10. Procedures will be revised to perform inspections of control rod guide tube (CRGT) thermal sleeves as indicated in MRP 2018-027. MRP 2018-027 refers to the Westinghouse NSAL 18-1 recommendation that, based on operating experience (OE) from international PWR plants related to wear of reactor vessel closure head control rod drive mechanism (CRDM) thermal sleeve flanges resulting in control rod stoppage during plant restart operations, a visual inspection should be performed during the next refueling outage after issuance of the NSAL, and during each subsequent refueling outage, for the tops of the CRGTs to determine whether any thermal sleeves have lowered significantly or are in a failed state. For the Surry plants, the guidance is to look for shiny marks on the top edge of the upper guide tube enclosure. Also, during the next under-head inspection, the guidance is to perform a visual inspection of the bottom of the thermal sleeve guide funnels to look for any shiny surfaces on the bottom surface of the guide funnel that would indicate that the thermal sleeve guide funnels have dropped to a point where they are in contact with the top of the guide tube. A visual inspection of thermal sleeve guide funnel elevations is recommended to identify whether any sleeves are noticeably lower than others (Primary component). 11. Procedures will be revised to require visual examinations (VT-3) for the following: a. Top and bottom edges of baffle plates to identify misalignment (Primary component). b. General condition of the baffle plates to identify warping or void swelling (Primary component). c. Surfaces of the upper internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component). d. Surfaces of the lower internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component). e. Clevis insert bolts and clevis insert dowels (Primary component).			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
7 (cont'd)		12. Procedures will be revised for contingency tasks to require inspection of the following expansion components if necessitated by relevant indications being found for associated primary components: a. Remaining control rod guide tube lower flange welds not inspected as Primary component (EVT-1) b. Control rod guide tube (CRGT) continuous section sheaths and C-tubes in accordance with the requirements of WCAP-17451-P, Revision 2. c. Bottom-mounted instrumentation column bodies (100% of BMI column bodies for which difficulty is detected during flux thimble insertion / withdrawal; VT-3) d. Lower support column bodies (25% of column bodies as visible from above the core plate; VT-3) e. Barrel-former bolts (100% of accessible bolts, minimum of 75% of the total population; UT) f. Lower support column bolts (100% of accessible bolts, minimum of 75% of the total population; UT) 13. Procedures will be revised to require that the inspections for the radial support keys and clevis inserts are to include the Stellite wear surfaces (Primary component, MRP 2018-022). 14. Procedures will be revised to require visual inspections (VT-3) of the guide cards in at least 37 of the 48 control rod guide tubes, and will include associated acceptance criteria. Guidance from WCAP-17451-P, "Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections," and MRP 2018-07, "Transmittal of NEI 03-08 Needed Guidance to Address Accelerated Guide Card Wear Operating Experience (OE) Discussed in NSAL-17-1," will be included for the inspection of control rod guide cards.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
7 (cont'd)		15. Procedures will be revised to require visual examinations (EVT-1), and will include associated acceptance criteria, for 100% of the accessible weld length of the OD of the LGW and 3/4" of adjacent base metal (minimum 50% examination coverage). (Primary component) 16. Procedures will be revised for contingency tasks to inspect the following expansion components if necessitated by relevant indications being found for associated primary components, and will include associated acceptance criteria: a. Core barrel upper, middle, and lower axial welds (100% of weld length and 3/4" of adjacent base metal - minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld; EVT-1) • A one-time enhanced visual (EVT-1) examination of the core barrel middle axial weld (MAW) and lower axial weld (LAW) will be performed during the sixth inservice inspection interval (i.e., a "50-year inspection") no later than six months prior to the subsequent period of extended operation. The examination will include coverage for 100% of the accessible weld lengths from the core barrel OD and 3/4" of base metal on each side the weld AND a vertical zone on each side of the inaccessible portion of the barrel containing the known location of the axial weld. Each vertical zone shall be a minimum of 3/4" wide and cover the full distance parallel to the inaccessible height of the weld. b. Core barrel upper girth weld (100% of weld length and 3/4" of adjacent base metal –minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld; EVT-1) c. Lower support forging (25% of bottom (non-core side) surface; VT-3) d. Upper core plate (25% of core-side surfaces; VT-3) 17. A procedure for visual examinations will be revised to identify the examiner qualifications which are applicable for EVT-1 examinations.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
8	Flow-Accelerated Corrosion program	The Flow-Accelerated Corrosion program is an existing condition monitoring program that will be enhanced as follows: 1. An engineering evaluation will be performed for systems that have been excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time. The purpose of the engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The engineering evaluation and modeling changes for the FAC program will be completed prior to entering the subsequent period of extended operation. 2. A re-evaluation of the erosion susceptibility determination that identified plant systems in the scope of subsequent license renewal that were previously excluded from monitoring will be performed to re-affirm that the appropriate basis for exclusion either is in-service operational and testing time less than 100 hours per year, or is a technical evaluation specifically developed to exclude a system. 3. A re-evaluation will be performed to determine whether plant conditions (e.g., valve throttling) have changed such that susceptibility to erosion has increased for plant systems within the scope of subsequent license renewal. 4. Procedure will be revised to confirm that inspection scope expansions include the items noted below and to confirm that independent reviews of inspection scope expansions are independently reviewed by a qualified FAC engineer. • Any component within two pipe diameters downstream of the component displaying significant wear, or within two pipe diameters upstream if that component is an expander or expanding elbow. • The two most susceptible components from the CHECWORKS relative wear rate ranking in the same train containing the piping component displaying significant wear	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2 Response to RAIs - Set 2 Response to RAIs - Set 3 & 4 Correction to Response to RAIs - Set 3 & 4	2,4, 7,8,9

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
8 (cont'd)		• Corresponding components from other trains. • Inspections of additional components until no additional components with significant wear are detected.			
9	Bolting Integrity program	The Bolting Integrity program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to provide inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet to four feet (or less) will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. 2. Procedures will be revised for inspections of pressure-retaining closure bolting in locations that preclude detection of joint leakage, such as in submerged environments or where the piping system contains air for which leakage is difficult to detect. The inspections will be performed to detect loss of material. A requirement will be included to inspect bolt heads when made accessible, and bolt threads if joints are disassembled. At a minimum, in each 10-year interval during the subsequent period of extended operation, inspections shall be completed for a representative sample of at least 20% of the population, up to a maximum of nineteen, for each material/environment combination.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
9 (cont'd)		3. A new procedure will be developed to provide guidance for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination is not corrected by repair or replacement, thus requiring that additional inspections be performed. The number of additional inspections will be determined in accordance with the Corrective Action Program; however no fewer than five additional (or 20%, whichever is less) inspections of different components having the same material/environment/aging effect combination are required for each inspection that did not meet the acceptance criterion. For a two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same material, environment, and aging effect combination. The additional inspections are to be completed within the same interval (e.g., refueling outage or 10-year inspection interval). If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the Corrective Action Program.			
10	Steam Generators program	The Steam Generators program is an existing condition monitoring program that is credited.	Ongoing	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
11	Open-Cycle Cooling Water program	The Open-Cycle Cooling Water program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that will be enhanced as follows: 1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program. 2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation. 3. The internal lining of 30 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation. 4. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement. 5. Procedures will be revised to provide guidance for internal inspection of carbon fiber reinforced polymer piping for aging effects such as voids, blistering, bubbles, cracking, crazing and delamination. 6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the Structures Monitoring program (B2.1.34) that are consistent with the requirements of ACI 349.3R.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 1 Response to RAIs - Set 1 Response to RAIs - Set 2 Response to RAIs - Set 3 & 4 Correction to Response to RAIs - Set 3 & 4 First Annual Amendment and Supplement to SLRA: Change Notice 4 Supplement to SLRA: Change Notice 5	2,3,6, 7,8,9 10, 11

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
11 (cont'd)		7. Procedures will be revised to require personnel who perform visual inspections and evaluation of carbon fiber reinforced polymer piping to be VT-1 qualified consistent with IWA-2300 of ASME Section XI and Mandatory Appendix II of ASME Code Case N-871. Examination procedures and personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI and section 5400 of ASME Code Case N-871. 8. Procedures will be revised to require installed CFRP linings be 100% visually examined in accordance with ASME Code Case N-871 section 5213 during an inspection period between three and six years following return of the repaired area to service; and a minimum of once per 10 year inservice inspection interval thereafter in the same inspection period of each succeeding inspection interval. 9. Procedures will be revised to require accessible surfaces of the CFRP linings at each terminal end to be acoustically impact tap examined in accordance with Mandatory Appendix V, "Inservice Examination", Section V-2500, ASME Code Case N-871 section 5250(a), section 5250(c), and Section 5350. The acoustic examination of terminal ends will be capable of detecting and sizing delaminations and voids in any composite or bonding layer with dimensions equal to or less than those permitted by Section 4390(b)(3). The acoustic impact tap examination procedure sections will also be enhanced to add Section 5111(d), that provides consideration of the impact of in-situ ambient noise levels on application of the procedure and qualification of procedures and personnel. The qualification testing will be conducted in an area where the ambient noise level is equal to or higher than the noise level where the in-situ testing will be performed. The expansion rings need not be removed for this examination provided examinations of adjacent surfaces do not indicate the presence of new unacceptable indications that could extend beneath the rings.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
11 (cont'd)		10. Procedures will be revised to periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. 11. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering. 12. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results. 13. Procedures will be revised to require all areas previously documented in accordance with ASME Code Case N-871 Section V-1100(b) shall be re-examined, measured, and compared with the previous inspection records. Any indications of flaw growth will be required to be repaired consistent with ASME Code Case N-871. Documentation of the repair, location and dimensions will be required. Any new flawed areas shall be evaluated consistent with ASME Code Case N-871. 14. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses. 15. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions. 16. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing "hoop" bands or rust staining from such reinforcing elements.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
11 (cont.'d)		17. Procedures will be revised to include the following CFRP defect inspection acceptance criteria for air voids, bubbles, blisters, delaminations and other defects (such as cracking and crazing): <u>Air Voids</u> For embedded air voids of area less than or equal to 25 square inches that have been visually detected in layers beneath the topcoat, they shall be repaired in accordance with ASME Code Case N-871 section 4390 (b)(1) and (b)(2) unless otherwise specified in the design documents. All other defects and all voids larger greater than 25 square inches shall be rejected, and a repair designed to maintain water tightness of the system. <u>Bubbles, blisters or other defects</u> If bubbles or blisters with major dimension exceeding one inch are detected anywhere within the protective epoxy topcoat, they shall be removed and repaired in accordance with ASME Code Case N-871 Section 4380(d). <u>Delaminations or Voids</u> Unless permitted by design documents, acceptance criteria for acoustic tap examination of terminal ends shall be consistent with ASME Code Case N-871 section 5350 (a) and (b)			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
11 (cont'd.)		18. Procedures will be revised to include the following defect repair criteria as part of the corrective actions.: For air void defects Repairs shall be consistent with ASME Code Case N-871 section 4390 (b)(3) and (b)(4) For bubbles, blisters or other surface defects Repairs shall be consistent with ASME Code Case N-871 section 4390 (d) For all other defects and all voids larger than 25 square inches A repair shall be designed to maintain water-tightness of the system consistent with ASME Code Case N-871 section 4390 (d) A final visual inspection shall be performed to verify the CFRP system has achieved the percentage of cure corresponding to achievement of required mechanical properties before placing the repaired piping back in service. In no case shall the system be placed in service before achieving 85% cure. 19. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation. 20. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.		

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
12	Closed Treated Water Systems program	The Closed Treated Water Systems program is an existing condition monitoring and mitigation program that will be enhanced as follows: 1. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For component internal inspections, accessible surfaces will be inspected, subject to a minimum 20% surface area examination coverage. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed as necessary to allow for a meaningful examination. The surface to be examined should be clean and free of corrosion products, slag, dirt, grease, and scale, loose or cracked paint or any foreign material that interferes with examination results. If protective coatings are present, the condition of the coating will be documented. 2. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, water treatment program, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
12 (cont'd.)		3. A new procedure will be developed to specify that, where practical, the rate of any degradation is evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 4. A new procedure will be developed to specify that additional inspections will be performed if any inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.			
13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program	The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to specify visual inspections for the effects of general corrosion, deformation, cracking, and wear on the rails in the rail system. 2. Procedures will be revised to specify visual inspections for general corrosion, deformation, cracking, wear and loose or missing fasteners and other conditions indicative of loss of bolting preload for the new fuel transfer elevator.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
14	Compressed Air Monitoring program	The Compressed Air Monitoring program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to perform opportunistic visual inspections of internal surfaces of compressed air system components downstream of the dryers to verify the effectiveness of the compressed air system control of moisture (dewpoint) and particulate. Visual inspection results will be compared to previous results to ascertain if adverse long-term trends exist. Deficiencies will be documented in the Corrective Action Program and evaluations performed for test or inspection results that do not satisfy established criteria as defined in the applicable procedures.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
15	Fire Protection program	The Fire Protection program is an existing condition and performance monitoring program that will be enhanced as follows: 1. Procedures will be enhanced to require fire damper assemblies (rather than fire damper housings) to be visually inspected for loss of material and determined to be acceptable if there are no signs of degradation that could result in loss of fire protection capability due to loss of material. 2. Carbon dioxide and halon systems air flow testing procedures will be enhanced to trend air flow test data. In addition, procedures will be enhanced to specify that inspection results for the halon and CO2 systems meet the acceptance criteria if there are no indications of excessive loss of material. 3. Procedures will be revised to require an assessment for additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. If degradation is detected within the inspection sample of penetration seals, the scope of the inspection is expanded to include additional seals in accordance with the plant's corrective action program. Additional inspections would be 20% of each applicable inspection sample; however, additional inspections would not exceed five. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Response to RAIs - Set 2	2,7

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
16	Fire Water System program	The Fire Water System program is an existing condition monitoring program that will be enhanced as follows: 1. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner. For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. At each unit, a sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population. 2. Procedures will be revised to specify: a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow. b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action. c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer environment, and aging effect combination. d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 1 Supplement to SLRA: Change Notice 2 Supplement to SLRA: Change Notice 3 Response to RAIs - Set 3 & 4 Correction to Response to RAIs - Set 3 & 4	2,3,4, 5,8,9

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
16 (cont'd)		3. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected. b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 4. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
16 (cont'd)		5. Prior to the subsequent period of extended operation, the insulation on the exterior surfaces of the fire water storage tanks (FWSTs) will be permanently removed. Wall thickness measurements will be performed on external tank areas exhibiting unexpected degradation. Refurbishment/recoating will be performed consistent with the severity of the degradation identified and commensurate with the potential for loss of intended function. Inspections of external tank surfaces will be on a refueling cycle frequency. 6. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. 7. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. 8. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage. As part of the drainage reconfiguration, visual inspections and wall thickness measurements will be performed on the Unit 1 hydrogen seal oil system deluge sprinkler pipe that does not drain. In addition, wall thickness examination of the Unit 1 main transformer deluge sprinkler piping that does not allow drainage will also be performed as part of the drainage reconfiguration. Piping with unexpected degradation will be replaced.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
16 (cont'd)		9. The program will be revised to require inspections and tests be performed by personnel qualified in accordance with site procedures and programs for the specified task. 10. Procedures will be revised to require when degraded coatings are detected by internal coating inspections, acceptance criteria and corrective action recommendations consistent with the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks program are followed in lieu of NFPA 25 section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7(3) in vicinity of the loss of material. Vacuum box testing as stated in NFPA 25 Section 9.2.7(5) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds. 11. The activity of the jockey pump will be monitored consistent with the "detection of aging effects" program element of NUREG-2191, Section XI.M41. 12. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
17	Outdoor and Large Atmospheric Metallic Storage Tanks program	The Outdoor and Large Atmospheric Metallic Storage Tanks program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require periodic visual inspections of the refueling water storage tanks (RWSTs) be performed at each outage to confirm that the insulation caulking/sealant at the RWST concrete foundation is intact. The visual inspections of caulking/sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the caulking/sealant will be repaired or replaced and follow-up examination of the tank's surfaces conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWST external insulation is removed and sampled for external surface visual examinations. 2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs and CATs be performed to identify any loss of material or cracking. A minimum of either 25, one square foot sections or 20% of the surface area of insulation will be required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation.	Program will be implemented and inspections or tests begin 10 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Response to RAIs -Set 2	2,7

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
17 (cont'd)		3. Procedures will be revised to require emergency condensate storage tank (ECST) weep holes be inspected for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed. Accessible external metallic tank surfaces visible from inside the ECST piping penetration house will also require inspection once each refueling cycle as an indication of external ECST surface condition. Volumetric examination thickness measurements of the bottom of both emergency condensate makeup tanks (ECMTs) (100% of the surface exposed to soil) and both emergency condensate storage tanks will be performed and will occur during each 10-year period starting ten years before the subsequent period of extended operation. Results will be forwarded to engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates. One-time thickness measurements of a sample of the ECSTs vertical wall will be performed prior to the subsequent period of extended operation (SPEO) to assess potential degradation due to removable access plug leakage. The sample will examine the ECST vertical steel shell region between the three weep holes at the tank bottom associated with removable access plug leakage and vertically from that tank bottom junction to a distance of six feet along the vertical shell at the tank as a region potentially most susceptible to degradation. The inspection results will be projected to end of the SPEO to confirm the ECSTs intended functions will be maintained throughout the SPEO based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
17 (cont'd)		4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of both FWSTs and both RWSTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates 5. For the carbon steel tanks (FWST, ECST, ECMT), procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, and surface conditions. The revised procedure will require the inspector confirm adequate lighting is available at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less is recommended. For distant surface inspections, viewing aids such as binoculars may be used. For internal inspections, accessible surfaces will be inspected. Cleaning will be performed as necessary to allow for a meaningful examination. If protective coatings are present, the condition of the coating will be noted. 6. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191. If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
17 (cont'd)		b. For other sampling based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit. The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
18	Fuel Oil Chemistry program	The Fuel Oil Chemistry program is an existing mitigative and condition monitoring and preventive program that will be enhanced as follows: 1. Procedures will be revised to include the emergency diesel generator (EDG) fuel oil base tanks within the scope of the Fuel Oil Chemistry program. 2. Existing procedures will be revised to include a requirement for quarterly sampling of the EDG auxiliary fuel oil tanks and EDG fuel oil base tanks for particulates and water. 3. Procedures will be revised to require the following fuel oil storage tanks within the scope of subsequent license renewal be drained, cleaned, and the internal surfaces visually inspected for degradation within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation: • Underground fuel oil storage tanks • AAC diesel generator fuel oil tank If degradation is found during the internal visual inspection, bottom thickness measurements will be performed. Visual and volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute. 4. Procedures will be developed to perform periodic bottom thickness measurements of the following tanks within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation: • EDG auxiliary fuel oil tanks • Diesel fire pump fuel oil tank • Emergency service water pump fuel oil tank Volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute.	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2	2,4

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
18 (cont'd)		5. Procedures will be developed to require an engineering evaluation be performed to document, evaluate, and trend visual and volumetric (as applicable) inspection results for the following fuel oil storage tanks: • Underground fuel oil storage tanks • AAC diesel generator fuel oil tank • EDG auxiliary fuel oil tanks • Diesel fire pump fuel oil tank • Emergency service water pump fuel oil tank The procedures will require unacceptable inspection results, as determined in the engineering evaluation, be documented in the Corrective Action Program. Bottom thickness measurements will be required to be evaluated against the design thickness and corrosion allowance. The frequency of future inspections will not be allowed to be reduced if bottom thickness measurements indicate the corrosion allowance will be exceeded prior to the next scheduled inspection. If a tank does not have a stated corrosion allowance, the tank will be evaluated for acceptability in the engineering evaluation. The engineering evaluation will evaluate the need to reduce the time period between future inspections based on inspection results. 6. Prior to the subsequent period of extended operation, a one-time inspection will be performed on the accessible internal surfaces on one EDG fuel oil base tank at Surry. Inspection will be limited due to the restricted accessibility through the tank sampling port. A visual inspection will be performed using a boroscope or equivalent instrument which will provide an acceptable level of information regarding tank degradation on the accessible internal surfaces. 7. Procedures will be revised to require a biocide be added when biological activity is detected or if there is evidence of tank internal corrosion.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
19	Reactor Vessel Material Surveillance program	The Reactor Vessel Material Surveillance program is an existing condition monitoring program that will be enhanced as follows: 1. The RV Material Surveillance program for Unit 1 will be amended for Capsule Y to be pulled during the subsequent period of extended operation. Capsule Y will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. 2. The RV Material Surveillance program for Unit 2 will be amended for Capsule T to be pulled during the subsequent period of extended operation. Capsule T will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.	Program and SLR enhancements will be implemented 6 months prior to the subsequent period of extended operation. This program includes removal and testing of at least one capsule during the subsequent period of extended operation, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
20	One-Time Inspection program	The One-Time Inspection program is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an aging management program that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action. The One-Time Inspection program will perform a magnetic particle test inspection of the continuous circumferential transition cone closure weld on each steam generator (essentially 100% examination coverage of each weld) prior to the subsequent period of extended operation. Industry and plant-specific operating experience will be evaluated in the development of this program.	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Response to RAIs -Set 1	2,6

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
21	Selective Leaching program	The Selective Leaching program is a new condition monitoring program that will monitor components constructed of materials which are susceptible to selective leaching. The selective leaching program includes a one-time inspection for susceptible components exposed to closed cycle cooling water and treated water environment since plant-specific operating experience has not revealed selective leaching in these environments, as well as opportunistic and periodic inspections for susceptible components exposed to raw water, waste water, and soil (which may include groundwater) environments. Industry and plant-specific operating experience will be evaluated in the development of this program.	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
22	ASME Code Class 1 Small-Bore Piping program	The ASME Code Class 1 Small-Bore Piping program is a new condition monitoring program that augments the existing ASME Code, Section XI requirements and is applicable to ASME Code Class 1 small-bore piping and systems with a NPS diameter less than 4 inches and greater than or equal to 1 inch. This program provides for volumetric examination of a sample of full penetration (butt) welds and partial penetration (socket) welds in Class 1 piping to manage cracking due to stress corrosion cracking or thermal or vibratory fatigue loading. Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. The extent and schedule for volumetric examination is based on plant-specific operating experience and whether actions have been implemented that effectively mitigate the cause(s) of any past cracking. The program provides for a one-time inspection of a sample of the population of welds (butt welds or socket welds) for plants that have not experienced cracking or have experienced cracking but have implemented corrective actions, such as a design change, to effectively mitigate the cause(s) of the cracking. The program provides for periodic inspection of a sample of the population of welds (butt welds or socket welds) that have experienced cracking and have not implemented corrective actions to effectively mitigate the cause(s) of the cracking. Industry and plant-specific operating experience will be evaluated in the development of this program.	Program will be implemented and inspections are completed within 6 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
23	External Surfaces Monitoring of Mechanical Components program	The External Surfaces Monitoring of Mechanical Components program is an existing condition monitoring program that will be enhanced as follows: 1. The Engineering walkdown procedure will be revised to include an item in the walkdown checklist to inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture. 2. The Engineering walkdown procedure will be revised to add the following requirements: a. Metallic Components • No surface imperfections, loss of wall thickness, flaking, or oxide coated surfaces • No blistering of protective coating • No evidence of leakage (for detection of cracks) on the surfaces of stainless steel, aluminum, and copper alloy (>15% Zn or >8% Al) components • No accumulation of debris on air-side heat exchanger surfaces b. Elastomers and Flexible Polymers • No exposure of reinforcing fibers, mesh or underlying metal (for elastomers or flexible polymers with internal reinforcement) • No blistering, loss of thickness, dimensional change, or scuffing • No hardening of elastomeric elements as evidenced by a loss of suppleness during tactile inspection c. Insulation Metallic Jacketing • Inspect insulation metallic jacketing for any damage that would permit in-leakage ofmoisture. d. HVAC Closure Bolting • Check that a sample of closure bolting that is in reach is not loose	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 1	2,3

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
23 (cont'd)		3. The Engineering walkdown procedure will be revised to specify that walkdowns will be performed at a frequency not to exceed one refueling cycle. Since some surfaces are not readily visible during both plant operations and refueling outages, the enhancement will also specify that such surfaces will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. 4. The Engineering walkdown procedure will be revised to provide non-ASME Code inspection guidance related to lighting, distance and offset for walkdown inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. 5. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. A minimum of 25 inspections for cracking will be performed from each of the stainless steel, aluminum, and copper alloy (>15% Zn or >8% Al) component populations assigned to the program every ten years. For insulated components exposed to condensation, a minimum of 25 one foot axial length sections and components for each material and environment combination will be inspected for loss of material and cracking after the insulation is removed. The new procedure will specify that the inspections focus on the components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
23 (cont'd)		6. The Engineering walkdown procedure will be revised to specify that visual inspection of elastomers and flexible polymers will be supplemented by tactile inspection to detect hardening. Visual inspections will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 7. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 8. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions. 9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections to detect cracking in aluminum, stainless steel, and copper alloy (>15% Zn or >8% Al) components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
23 (cont'd)		The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., 10-year inspection interval) in which the original inspection was conducted.			
24	Flux Thimble Tube Inspection program	The Flux Thimble Tube Inspection program is an existing condition monitoring program that will be enhanced as follows: 1. An inspection procedure will be developed specifically for flux thimble tube eddy-current inspections, rather than continuing to use a generic procedure for tubing inspection. The procedure will include the acceptance criterion, with the basis, for loss of material for the inner flux thimble tube, and identify remediating actions to be implemented if the acceptance criterion is exceeded.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2
25	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspection of metallic components for flaking or oxide-coated surfaces. 2. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following: a. Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., "ballooning" and "necking") b. Loss of wall thickness c. Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers		SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2	2,4

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
25 (cont'd)		3. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 4. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For internal inspections, accessible surfaces will be inspected. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed, as necessary, to allow for a meaningful examination. If protective coatings are present, the procedure will require the condition of the coating to be documented. 5. Procedures will be revised to specify that follow-up volumetric examinations are performed where irregularities that could be indicative of an unexpected level of degradation are detected for steel components exposed to raw water, raw water (potable), or waste water. 6. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
25 (cont'd)		The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. 7. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 8. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions. 9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
26	Lubricating Oil Analysis program	The Lubricating Oil Analysis Program is an existing preventive program that will be enhanced as follows: 1. Procedures will be revised to incorporate existing guidelines for lube oil and electro-hydraulic control fluids into sampling procedures. 2. Procedures will be revised to include a statement that phase-separated water in any amount is not acceptable.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
27	Buried and Underground Piping and Tanks program	The Buried and Underground Piping and Tanks program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings. 2. Procedures will be revised to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation. 3. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." 4. A cathodic protection system will be installed for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation. 5. A cathodic protection system will be installed for protection of each unit's buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building five years before entering the subsequent period of operation. 6. Procedures will be enhanced to perform two soil corrosivity samples: one adjacent to the Unit 1 circulating water inlet piping and another adjacent to the Unit 2 circulating water inlet piping. Sampling will be performed on a ten year interval. Data collected at each location will include: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, corrosivity of carbon steel reinforcement and concrete degradation in high sulfate, high chlorides, and acidic environments will be evaluated.	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2 Response to RAIs -Set 1 Response to RAIs -Set 3 & 4 Correction to Response to RAIs -Set 3 & 4 First Annual Amendment and Supplement to SLRA: Change Notice 4 Supplement to SLRA: Change Notice 5 Supplement to SLRA: Change Notice 6	2,4,6, 8,9,10 11,12

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
27 (cont'd)		7. Procedure(s) will be developed to perform a one-time inspection (one excavation) for evidence of concrete aging (below grade) associated with the south side of the Turbine Building, with the following requirements: a. Prior to excavation, it shall be confirmed that the south side of the Turbine Building is bare concrete below grade. b. If bare concrete is confirmed, then: • A minimum of 50 ft^2 concrete surface area below groundwater level will be inspected by the one-time inspection. • The evaluation of the one-time inspection results shall include evaluation of the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R. • If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, then the area containing the degradation will be evaluated for acceptability by a responsible Civil Engineer using the Corrective Action Program. The evaluation shall include the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R. • If observed age-related degradation exceeds ACI 349.3R Tier-1 criteria, a subsequent inspection will be performed within ten years to determine if the previously observed degradation remains within the parameters evaluated during the previous inspection. If the degradation during the subsequent inspection more than marginally exceeds the evaluated parameters from the previous inspection, then within five years an excavation of one 96-inch CW pipe will be performed to inspect a surface area of 50 ft^2 located below groundwater level. c. If bare concrete is not confirmed, then: • Excavation of one 96-inch CW pipe will be performed to inspect a surface area of 50 ft2 located below groundwater level.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
27 (cont'd)		8. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. The external loss of material rate is verified: • Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate. • Every 2 years when using the 100 mV minimum polarization. • Every 5 years when using the -750 or -650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm). When using the electrical resistance corrosion rate probes: a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
27 (cont'd)		9. Procedures will be revised to specify that soil sample results indicating corrosivity of greater than 10 points using the "carbon steel" column in Table 9-4, "Soil Corrosivity Index from BPWORKS," of EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," require evaluation of potential scope expansion or category transition. 10. Procedures will be revised to specify that when an aggressive groundwater/soil environment is confirmed, corrective actions are required, including confirmatory groundwater resampling, as well as groundwater sampling on a quarterly basis for at least one year (i.e., four quarters). The results of the quarterly groundwater samples will be trended, and if groundwater chemistry continues to exceed the aggressive environment thresholds, additional corrective actions will be determined. The additional corrective actions may include items such as further sampling, installation of more wells, more frequent inspections of the surrogate structure, and/or the development of a plant specific aging management activity.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
28	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program	The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, “Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.” • Circulating water system waterbox air separating tanks • Condensate polishing outlet piping (short segment; entire length is inspected) • Vacuum priming tanks • Vacuum priming seal water separator tanks • Auxiliary steam drain receiver tank • Water treatment piping (short segment; entire length is inspected) • Flash evaporator demineralizer isolation valve • Brominator mixing tank • Pressurizer relief tanks 2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage. 3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program.	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2 Response to RAIs -Set 1 Response to RAIs -Set 3 & 4 Correction to Response to RAIs -Set 3 & 4	2,4,6, 8,9

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
28 (cont'd)		4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. 5. Procedures will be revised to require cementitious coatings/linings inspectors to have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience. 6. Procedures will be revised to require opportunistic inspections of piping internally lined with concrete and include aging associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. 7. Component cooling heat exchanger channel head coatings are inspected on a one-year inspection interval. Procedures will be revised to require that if two subsequent inspections demonstrate no change in coating condition (i.e. at least three consecutive inspections with no change in condition), inspection frequencies at those locations may be conducted consistent with inspection Category B of NUREG-2191 Table XI.M42-1. 8. Procedures will be revised to require a coatings specialist to prepare the coatings post-inspection condition assessment report. A pre-inspection review will be performed of the coating inspections and any subsequent repair activities from the previous two coatings post-inspection condition assessment reports, when available. 9. Procedures will be revised to require inspection results are evaluated against acceptance criteria to confirm that the components' intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate and extent of degradation. Where practical, (e.g., wall thickness measurements, blister size and frequency), degradation is projected until the next scheduled inspection.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
28 (cont'd)		10. Procedures will be revised to: a. Specify there are no indications of peeling or delamination. b. Require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material. c. Require, as applicable wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. 11. Procedures will be revised to permit the "removal" of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation. 12. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if: a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal b. the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered) c. adhesion testing using ASTM International Standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area, d. an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component and e. follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
28 (cont'd)		13. Procedures will be revised to require when a blister does not meet acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain inservice should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister. 14. Procedures will be revised to require additional inspections be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
28 (cont'd)		These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections will include inspections with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. 15. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
29	ASME Section XI, Subsection IWE program	The ASME Section XI, Subsection IWE program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants." 2. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used. 3. Procedures will be revised to augment visual examinations with surface examinations to manage cracking in the containment pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature steel piping penetrations. Surface examinations will be performed once during each ten year interval. 4. Procedures will be revised to specify a one-time volumetric examination of metal liner surfaces that are inaccessible from one side if triggered by plant-specific operating experience. The trigger for this supplemental examination is plant-specific occurrence or recurrence of measurable metal liner corrosion (base metal material loss exceeding 10% of nominal plate thickness) initiated on the inaccessible side or areas, identified since the date of issuance of the initial renewed license.	Program and SLR enhancements, will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2	2,4

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
29 (cont'd)		This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or other relevant considerations such as environment. Any identified degradation is addressed in accordance with the applicable provisions of the ASME Section XI, Subsection IWE program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically, with 95% confidence, that 95% of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10% loss of nominal thickness.			
30	ASME Section XI, Subsection IWL program	The ASME Section XI, Subsection IWL program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to specify that inspection results be compared to previous results to identify changes from prior inspections, and that quantitative measurements are recorded and trended for applicable parameters monitored or inspected. 2. Procedures will be revised to specify that inspection results be compared to previous results to determine if degradation is passive for application of second-tier acceptance criteria as specified in ACI 349.3R-02, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
31	ASME Section XI, Subsection IWF program	The ASME Section XI, Subsection IWF program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be enhanced to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 2. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants will be in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339. 3. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used. 4. Procedures will be revised to specify that for NSSS component supports, Class 1 high strength bolting greater than one inch nominal diameter, including ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), will be monitored for SCC. 5. Procedures will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation.	Program will be implemented and a one-time inspection of an additional 5% of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports is conducted within 5 years prior to the subsequent period of extended operation, and are to be completed prior to the subsequent period of extended operation, are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2	2,4

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
31 (cont'd)		6. Procedures will be revised to specify that, for NSSS component supports, high-strength bolting greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts. 7. Procedures will be revised to specify that, if a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, then the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.			
32	10 CFR 50, Appendix J program	The 10 CFR 50, Appendix J program is an existing performance monitoring program that is credited.	Ongoing	SLRA, Appendix A, Table A4.0-1	2
33	Masonry Walls program	The Masonry Walls program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to clarify qualifications for personnel performing inspections of masonry walls and concrete to be consistent with ACI 349.3R-02. 2. Procedures will be revised to explicitly address the trending of inspection results and projection to the next inspection interval. The procedure will be revised to include acceptance criteria for masonry wall inspections that will be used to ensure observed aging effects (cracking, loss of material, or gaps between the structural steel supports and masonry walls) do not invalidate the evaluation basis of the wall or impact its intended function.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
34	Structures Monitoring program	The Structures Monitoring program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. Inspections for the added structures will be performed under the enhanced program in order to establish quantitative baseline inspection data prior to the subsequent period of extended operation. 2. Procedures will be revised to add the oiled-sand cushion to the inspection of the fire protection/domestic water tank foundation. 3. Procedures will be revised to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used. 4. The checklist for structural and support steel will be revised to indicate: “Are any connection members loose, missing or damaged (bolts, rivets, nuts, etc.)?”. 5. Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002. Procedures will be revised to eliminate options for inspector qualifications that are not consistent with ACI 349.3R-002.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation. A baseline inspection for wooden poles will be performed prior to January 1, 2031	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2 Supplement to SLRA: Change Notice 3 Response to RAIs -Set 2 Response to RAIs -Set 3 & 4 Correction to Response to RAIs -Set 3 & 4	2,4,5, 7,8,9

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
34 (cont'd)		6. Procedures will be revised to specify that wooden pole inspections will be performed at a frequency not to exceed every eight years. Visual examinations will detect loss of material and change in material properties. Visual examinations will be augmented, as required to detect change in material properties, with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings and excavations. 7. Procedures will be revised to specify that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 8. Procedures will be enhanced to specify VT-1 inspections to identify cracking on stainless steel and aluminum components. A minimum of 25 inspections will be performed every ten years during the subsequent period of extended operation from each of the stainless steel and aluminum component populations assigned to the Structures Monitoring program. If the component is measured in linear feet, at least one foot will be inspected to qualify as an inspection. For other components, at least 20% of the surface area will be inspected to qualify as an inspection. The selection of components for inspection will consider the severity of the environment. For example, components potentially exposed to halides and moisture would be inspected, since those environmental factors can facilitate stress corrosion cracking. 9. Procedures will be enhanced to specify that for the neutron shield tank (NST), loss of material due to corrosion, other than superficial corrosion, will be evaluated to ensure that the NST will continue to perform its intended functions, including structural support of the RPV.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
34 (cont'd)		10. Procedures will be enhanced to specify for the sampling-based inspections to detect cracking in stainless steel and aluminum components, additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. No fewer than five additional inspections for each inspection that did not meet acceptance criteria or 20% of each applicable material, environment, and aging effect combination will be inspected, whichever is less. Additional inspections will be completed within the 10-year inspection interval in which the original inspection was conducted. The responsible engineer will initiate condition reports to generate work orders to perform the additional inspections. The responsible engineer will evaluate the inspection results, and if the subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted. The responsible engineer will then determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the Corrective Action Program. 11. Procedures will be enhanced to specify that evaluation of neutron shield tank findings consider its structural support function for the reactor pressure vessel. 12. Procedures will be enhanced to also include LOCAs as events that require evaluation for potentially degraded structures by Civil/Mechanical Design Engineering.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
35	Inspection of Water Control Structures Associated with Nuclear Power Plants program	The Inspection of Water Control Structures Associated with Nuclear Power Plants program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to provide guidance for specification of bolting material, lubricants and sealants, and installation torque or tension to prevent degradation and assure structural bolting integrity. 2. Procedures will be revised to specify the preventive actions for storage discussed in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts” for ASTM A325, ASTM F1852, ASTM F2280, and/or ASTM A490 structural bolts. 3. Procedures will be revised for concrete inspection to require at least five years of experience (or ACI inspector certification) to be consistent with ACI 349.3R-2002.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2
36	Protective Coating Monitoring and Maintenance program	The Protective Coating Monitoring and Maintenance program is an existing mitigative and condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require that a pre-inspection review of the previous “two” condition assessment reports be performed prior to each refueling outage.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
37	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is an existing condition monitoring program that will be enhanced as follows: 1. A new procedure will be developed that will include guidance for the identification of adverse localized environments of temperature, moisture, radiation, contamination, and oxygen. 2. A new procedure will be developed that includes a description of testing methodology. Should testing be deemed necessary based on unacceptable visual indications of surface anomalies, a sample size of 20% of each cable and connection insulation material type found within the adverse localized environment with a maximum sample size of 25 will be tested. The following factors will be considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The technical basis for the sample selected is provided. 3. A new procedure will be developed that includes an inspection frequency of at least once every ten years. 4. A new procedure will be developed that includes the addition of jacket surface and connection covering material anomalies including embrittlement, melting, swelling, and surface contamination. 5. A new procedure will be developed that includes the performance of a review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
37 (cont'd)		6. A new procedure will be developed that describes acceptance criteria for both tests and visual inspections of the electrical cable and connection insulation material. 7. A new procedure will be developed that includes performance of an engineering evaluation of unacceptable test results and visual indications of cable and connection electrical insulation abnormalities. The evaluation will consider the age and operating environment of the component, as well as the severity of the abnormality and whether such an abnormality has previously been correlated to degradation of cable or connection insulation. Corrective actions include, but are not limited to, testing, shielding, or otherwise mitigating the environment or relocation or replacement of the affected cables or connections. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).			
38	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program	The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program is an existing performance monitoring program that will be enhanced as follows: 1. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment to evaluate reduced electrical insulation resistance by measuring cable resistance and capacitance. 2. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes recommendations for types of electrical insulation tests including insulation resistance tests, time domain reflectometry tests, or other tests judged to be effective in determining cable system insulation physical, mechanical, and chemical properties.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
38 (cont'd)		3. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes a test frequency of at least once every ten years with the first test completed prior to the subsequent period of extended operation. 4. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes acceptance criteria for the recommended test methods. 5. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment. The new procedure will include corrective actions and a requirement for an engineering evaluation to be performed when acceptance criteria are not met. The engineering evaluation will include a determination of whether the test frequency needs to be increased.			
39	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspection of in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. 2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly. 3. A procedure will be created for testing medium-voltage cable that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation. 4. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection. 5. A new recurring event and maintenance schedule will be created for testing the "A" RSST cables at least once every six years.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1 Supplement to SLRA: Change Notice 2	2,4

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
39 (cont'd)		6. A new recurring event and maintenance schedule will be created for testing the "B" RSST cables at least once every six years. 7. A new recurring event and maintenance schedule will be created for testing the "C" RSST cables at least once every six years. 8. A new procedure will be created for testing medium-voltage cable that includes a requirement that the specific type of test performed will be a proven test, utilizing one or more tests such as dielectric loss (dissipation factor (Tan-Delta)/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis, for detecting deterioration of the insulation system due to submergence (e.g., selected test is applicable to the specific cable construction: shielded and non-shielded, and the insulation material under test). 9. A plant-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables will be developed based on OE. 10. A new procedure will be created for testing medium-voltage cable that includes a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation. 11. A new procedure will be created for testing medium-voltage cable that includes acceptance criteria for tests and inspections.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
40	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables, exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development of this program.	Program will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2
41	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), low-voltage power cables (operating voltage less than 2 kV), exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development of this program.	Program will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
42	Metal-Enclosed Bus program	The Metal-Enclosed Bus program is an existing condition monitoring program that will be enhanced as follows: 1. Inspection procedures similar in scope and content to the procedures used to inspect other metal enclosed bus within scope of subsequent license renewal will be developed for the in-scope metal enclosed bus (MEB) associated with the 1A2 480V bus. 2. For inaccessible MEB internal or external segments, procedures will be revised to require initiation of a condition report that will result in an engineering evaluation of the inaccessible MEB segments that, together with the accessible MEB inspection and test program, will continue to maintain the MEB consistent with the current licensing basis during the subsequent period of extended operation. 3. Procedures will be revised to require inspection of accessible internal portions (bus enclosure assemblies) of MEBs for cracks, corrosion, and foreign debris. Accessible bus electrical insulation material will be inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, discoloration, or swelling, indicating overheating or aging degradation. Accessible internal bus insulating supports will be inspected for structural integrity and signs of cracks. Accessible gaskets, boots, and sealants will be inspected for elastomer degradation including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength that could permit water or foreign debris to enter the bus 4. Procedure revisions will include a requirement for a sample of accessible bolted connections not covered with heat shrink tape or boots to be inspected for loose or corroded bolted connections and damaged hardware including cracked or split washers.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
42 (cont'd)		5. Inspection procedures will be revised to add a note stating that 20% of the accessible bolted connection population, with a maximum of 25, is a representative sample. 6. A new recurring event and maintenance schedule will be created to inspect MEB associated with the 0-AAC-SW-0L bus on a maximum ten-year frequency. The first occurrence will be scheduled prior to the subsequent period of operation. 7. A new recurring event and maintenance schedule will be created to inspect MEB associated with the 1-EP-LCC-1A2 bus on a maximum ten-year frequency. The first occurrence will be scheduled prior to the subsequent period of operation. 8. Procedures will be revised to trend bus connection resistance values to provide information on the rate of connection degradation. 9. Accessible electrical insulation materials will be verified free from regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, and swelling. Accessible MEB internal surfaces will be verified to show no indications of corrosion, cracks, and foreign debris. Accessible elastomers (e.g., gaskets, boots, and sealants) will be verified to show no indications of surface cracking, crazing, scuffing, dimensional change (e.g., "ballooning" and "necking"), shrinkage, discoloration, hardening, and loss of strength. 10. Procedures will be revised to specify that when any acceptance criterion is not met, the unacceptable results are entered into the Corrective Action Program.			

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
43	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program	The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new condition monitoring program that consists of a representative sample of electrical connections tested prior to the subsequent period of extended operation. The results will be evaluated to determine if there is a need for subsequent periodic testing on a 10-year frequency. Industry and plant-specific operating experience will be evaluated in the development of this program.	Program will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2
44	High-Voltage Insulators program	The High-Voltage Insulators program is a new condition monitoring program that visually inspects high voltage insulator surfaces and metallic parts at least once every two years initially with the frequency adjusted based on plant specific operating experience. For high-voltage insulators that are coated, the visual inspection will be performed at least once every five years. Industry and plant-specific operating experience will be evaluated in the development of this program.	Program will be implemented 6 months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
45	Fatigue Monitoring program	The Fatigue Monitoring program is an existing preventive program that will be enhanced as follows: 1. The program cycle counting procedures will be revised to add the “Normal Charging and Letdown Shutdown and Return to Service” transient cycle associated with the ASME Code, Section XI, Appendix L analysis. 2. Procedures will be revised to require monitoring and tracking of transient cycles associated with the ASME Code, Section XI, Appendix L analysis be performed between the inspections for each ASME Code, Section XI, Appendix L location. Consistent with existing program cycle counting, a surveillance limit will be established to initiate corrective action prior to exceeding transient cycle assumptions in the ASME Code, Section XI, Appendix L analysis. 3. Procedures will be revised to expand existing corrective action guidance associated with exceeding a cycle counting surveillance limit to recommend consideration of component repair, component replacement, performance of a more rigorous analysis, performance of an ASME Code, Section XI, Appendix L flaw tolerance analysis, or scope expansion to consider other locations with the highest expected U_{en} values.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2
46	Neutron Fluence Monitoring program	The Neutron Fluence Monitoring program is an existing condition monitoring program that is credited.	Ongoing	SLRA, Appendix A, Table A4.0-1	2

Table 18-1 (CONTINUED)
SUBSEQUENT LICENSE RENEWAL COMMITMENTS

#	Program	Commitment	Implementation Schedule[a]	Source	Ref.
47	Environmental Qualification of Electric Equipment program	The Environmental Qualification of Electric Equipment program is an existing program that will be enhanced as follows: 1. Existing procedures will be enhanced to include a requirement for plants that are entering or have entered their subsequent period of extended operation to perform a walkdown once prior to the subsequent period of extended operation and every ten years thereafter. Accessible electrical EQ equipment will be visually inspected and the EQ environment evaluated to identify in-scope electrical equipment subjected to an adverse localized environment (ALE). If an ALE is found, evaluation of the impact of the ALE on EQ electrical equipment, including qualified life, will be performed. 2. Existing procedures will be enhanced to evaluate and take appropriate corrective actions, which may include changes to qualified life, when an unexpected adverse localized environment or condition is identified during operational or maintenance activities that affect the qualification of electrical equipment.	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.	SLRA, Appendix A, Table A4.0-1	2

a. The subsequent period of extended operation (SPEO) for Surry begins on May 25, 2032, for Unit 1 and January 29, 2033, for Unit 2.

18.6 REFERENCES

1. U. S. Nuclear Regulatory Commission, “Safety Evaluation Report Related to the Subsequent License Renewal of Surry Power Station, Units 1 and 2,” Final Report, March 2020 (ML20052F523)
2. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station Units 1 and 2 -Application for Subsequent Renewed Operating Licenses,” Serial No. 18-340, dated October 15, 2018 [(pkg ML18291A842), Appendix A, Table A4.0-1 (ML18291A828)]
3. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Submittal of Supplement to Subsequent License Renewal Operating Licenses Application for Sufficiency Review Change Notice 1,” Serial No. 18-448, dated January 29, 2019 (ML19042A137)
4. Letter from Gerald T. Bischof (Dominion) to NRC, “Surry Power Station Units 1 and 2 Supplement to Subsequent License Renewal Application Change Notice 2,” Serial No. 19-096, dated April 27, 2019 (ML19095A666)
5. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Supplement to Subsequent License Renewal Application Change Notice 3,” Serial No. 19-248, dated June 10, 2019 (ML19168A028)
6. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application - Response to Requests for Additional Information - Set 1,” Serial No. 19-269, dated June 27, 2019 (ML19183A386)
7. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application - Response to Requests for Additional Information - Set 2,” Serial No. 19-260, dated July 17, 2019 (ML19204A357)
8. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application - Response to Requests for Additional Information - Sets 3 and 4,” Serial No. 19-344, dated September 3, 2019 (ML19253B330)
9. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application - Response to Requests for Additional Information - Sets 3 and 4 Revised SLRA Mark-Ups,” Serial No. 19-344C, dated September 19, 2019 (ML19269B734)
10. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application First 10 CFR 54.21(b) Annual Amendment and Supplement to Subsequent License Renewal Application Change Notice 4,” Serial No. 19-385, dated October 14, 2019 (ML19294A044)
11. Letter from Mark D. Sartain (Dominion) to NRC, “Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application (SLRA) Supplement to Subsequent License

Renewal Application Change Notice 5," Serial No. 19-438, dated October 31, 2019 (ML19310E716)

12. Letter from Mark D. Sartain (Dominion) to NRC, "Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application (SLRA) Supplement to Subsequent License Renewal Application Change Notice 6," Serial No. 19-468, dated November 19, 2019 (ML19329A287)

13. Letter from Mark D. Sartain (Dominion) to NRC, "Surry Power Station (SPS), Units 1 and 2 - Subsequent License Renewal Application (SLRA) Supplement to Subsequent License Renewal Application Change Notice 7 Changes to Environmental Authorizations," Serial No. 20-262, dated February 20, 2020 (ML20054B996)