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9 15-172. Small Steam Line Break Accident - Power 15-153
9 15-173. Small Steam Line Break Accident - RCS Pressure 15-154

CHAPTER 15. ACCIDENT ANALYSES

9

15.1 METHODOLOGY

15.1.1 OVERVIEW

This chapter details the expected response of the plant to the spectrum of transients and accidents which constitute the design basis events. The methodologies used to analyze the Chapter 15, "Accident Analyses" transients and accidents fall into three general categories. These are the non-LOCA transient and accident analysis methodologies which are detailed in the Duke Power topical report DPC-NE-3005-PA (Reference 1), the Framatome Technologies Inc. LOCA analysis methodologies (References 2 and 3) described in Section 15.14, "Loss of Coolant Accidents," and the Duke Power offsite dose analysis methodology described in Section 15.1.10, "Environmental Consequences Calculation Methodology."

The DPC-NE-3005-PA topical report methodology was used to establish a new set of licensing basis analyses beginning with Oconee Unit 2 Cycle 18. The following transients and accidents are analyzed with the new methodology. The specific cases analyzed for each transient or accident are listed in Table 15-32.

15.2 Startup Accident

15.3 Rod Withdrawal at Power Accident

15.4 Moderator Dilution Accidents

15.5 Cold Water Accident

15.6 Loss of Coolant Flow Accidents

15.7 Control Rod Misalignment Accidents

15.8 Turbine Trip Accident

15.9 Steam Generator Tube Rupture Accident

15.12 Rod Ejection Accident

15.13 Steam Line Break Accident

15.17 Small Steam Line Break Accident

Section 15.1, "Uncompensated Operating Reactivity Changes", in the original FSAR was deleted since the plant transient response due to the effects of fuel depletion and xenon buildup are insignificant and do not challenge the Reactor Protective and Engineered Safeguards Systems or approach any design limits. Sections 15.10, "Waste Gas Tank Rupture Accident," 15.11, "Fuel Handling Accidents," 15.15, "Maximum Hypothetical Accident," and 15.16, "Post-Accident Hydrogen Control" do not require thermal-hydraulic transient analyses methods and were not reanalyzed in DPC-NE-3005-PA.

15.1.2 TOPICAL REPORTS

The topical reports which describe the analysis methodologies used in this chapter are as follows:

<u>DPC-NE-3000-PA</u>

9 DPC-NE-3000-PA, "Thermal-Hydraulic Transient Analysis Methodology," (Reference 4) describes the
9 RETRAN-02 (Reference 5) system transient thermal-hydraulic models and the VIPRE-01 (Reference 6)
9 core transient thermal-hydraulic models used by Duke Power to analyze most of the non-LOCA
9 transients and accidents. This report includes the standard nodalization model and the various code
9 options that are used.

9 DPC-NE-3005-PA

9 DPC-NE-3005-PA, "UFSAR Chapter 15 Transient Analysis Methodology," (Reference 1) describes the
9 Duke Power methodology for analyzing the UFSAR Chapter 15 non-LOCA transients and accidents for
9 the Oconee Nuclear Station. This report includes a description of the computer codes used, the physics
9 parameters, the setpoint methodology, and details of the initial conditions, boundary conditions,
9 acceptance criteria, and all other aspects of the methodology. The computer codes comprising this
9 methodology are RETRAN-02 (Reference 5), VIPRE-01 (Reference 6), CASMO-3 (Reference 7),
9 SIMULATE-3P (Reference 8), SIMULATE- 3K (Reference 9), TACO-3 (Reference 10), and
9 ARROTTA (Reference 26).

9 DPC-NE-1004-A

9 DPC-NE-1004-A, "Nuclear Design Methodology Using CASMO-3 / SIMULATE-3P," (Reference 11)
9 describes the Duke Power methodology for the neutronic simulation of the Oconee reactors with the
9 CASMO-3 (Reference 7) / SIMULATE-3P (Reference 8) codes.

9 DPC-NE-2003-PA

9 DPC-NE-2003-PA, "Core Thermal-Hydraulic Methodology Using VIPRE-01," (Reference 12) describes
9 the Duke Power methodology for core thermal-hydraulic analysis for Oconee using the VIPRE-01 code.
9 The non-statistical DNBR limit using the BWU CHF correlation is developed in this report.

9 DPC-NE-2005-PA

9 DPC-NE-2005-PA, "Thermal-Hydraulic Statistical Core Design Methodology," (Reference 13) describes
9 the Duke Power methodology for determining the statistical DNBR limits using the VIPRE-01 code.
9 This methodology allows the uncertainty in many of the DNB-related parameters to be combined into a
9 statistical DNBR limit, rather than to include each uncertainty explicitly in the thermal-hydraulic analysis.
9 For some of the transients and accidents the primary flowrate associated with less than four pumps in
9 operation, and the higher flow uncertainty at reduced flowrates, result in different statistical DNBR design
9 limits. The applicable limit is given for each analysis. The non-statistical DNBR limits using the BWU
9 correlations are developed in this report.

9 BAW-10192P

9 BAW-10192P, "BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator
9 Plants," (Reference 2) describes the RELAP5-based Framatome Technologies, Inc., LOCA Evaluation
9 Model. This topical report has been accepted by the NRC as in compliance with 10 CFR Appendix K
9 (Reference 14). The computer codes which comprise this methodology are RELAP5/MOD2-B&W
9 (Reference 15), CONTEMPT (Reference 16), REFLOD3B (Reference 17), and BEACH (Reference 18).
9 The Oconee large-break LOCA spectrum is analyzed with this Evaluation Model.

9 BAW-10154P

9 BAW-10154P, "B&W's Small-Break LOCA ECCS Evaluation Model," (Reference 3) describes the
9 CRAFT2-based Framatome Technologies, Inc., small-break LOCA Evaluation Model. This topical
9 report has been accepted by the NRC as in compliance with 10 CFR Appendix K (Reference 14). The
9 computer codes which comprise this methodology are CRAFT2 (Reference 19), FOAM2 (Reference 20),
9 and THETA1-B (Reference 21). The Oconee small-break LOCA spectrum is analyzed with this
9 Evaluation Model.

9 15.1.3 COMPUTER CODES AND CHF CORRELATIONS

9 RETRAN-02

9 The non-LOCA system transient thermal-hydraulic analyses use the RETRAN-02 code (Reference 5)
9 developed by the Electric Power Research Institute. RETRAN-02 has the flexibility to model any general
9 fluid system by partitioning the system into a one-dimensional network of fluid volumes and connecting
9 junctions. The mass, momentum, and energy equations are then solved by employing a semi-implicit
9 solution method. The equations are based on a homogeneous two-phase mixture, with capability for
9 phase separation via bubble rise and slip models. A non-equilibrium pressurizer model, special
9 component models for pumps, valves, and control systems, and general heat transfer modeling are
9 included. For transients which challenge the DNBR limit, RETRAN-02 provides core boundary
9 conditions to VIPRE-01 and SIMULATE-3P.

9 VIPRE-01

9 The core thermal-hydraulic and fuel pin analyses use the VIPRE-01 code (Reference 6) developed by the
9 Electric Power Research Institute. VIPRE-01 uses the subchannel analysis approach in which the fuel
9 assembly is divided into a number of quasi-one-dimensional channels that communicate laterally by
9 diversion crossflow and turbulent mixing. Conservation equations of mass, axial and lateral flow, and
9 momentum are solved. The flow field is assumed to be incompressible and homogeneous, with models
9 for subcooled boiling and co-current phase slip. VIPRE-01 accepts boundary conditions from
9 RETRAN-02 and SIMULATE-3P and determines the DNBR using the applicable CHF correlations.

9 CASMO-3

9 Nuclear constants are generated with the Studsvik of America code CASMO-3 (Reference 7) for use in
9 Oconee reload design (Reference 11). CASMO-3 is used for generating data used as input to the
9 SIMULATE codes.

9 SIMULATE-3P

9 Nuclear parameters and core power distributions are generated with the Studsvik of America code
9 SIMULATE-3P (Reference 8) for use in Oconee reload design (Reference 11). Nuclear constants are
9 input to SIMULATE-3P from the CASMO-3 code. SIMULATE-3P outputs are input to the
9 RETRAN-02 and VIPRE-01 codes.

9 SIMULATE-3K

9 The Studsvik of America code SIMULATE-3K (Reference 9) is used for transient three-dimensional
9 modeling of the rod ejection accident. SIMULATE-3K provides the same neutronics solution to
9 steady-state 3-D calculations as SIMULATE-3P. Nuclear constants are input to SIMULATE-3P from
9 the CASMO-3 code. SIMULATE-3K rod ejection analysis results are input to RETRAN-02 and
9 VIPRE- 01.

9 ARROTTA/1.10

9 The EPRI code ARROTTA (Reference 26) is used for transient three-dimensional (3-D) modeling of the
9 rod ejection accident. Nuclear constants are input to ARROTTA from the CASMO-3 code.
9 ARROTTA rod ejection analysis results are input to RETRAN-02 and VIPRE-01.

9 TACO-3

9 The TACO-3 code (Reference 10) developed by Framatome Technologies is used to calculate the initial
9 fuel pin thermal and mechanical conditions for the non-LOCA analyses performed by Duke Power, and
9 for the LOCA analyses performed by Framatome Technologies, Inc.

9 RELAP5/MOD2-B&W

9 The RELAP5/MOD2-B&W code (Reference 15) developed by Framatome Technologies, Inc., is used for
9 best-estimate and licensing transient simulation of pressurized water reactors. It has also been modified to
9 include the conservative models required for LOCA analysis per Appendix K to 10 CFR 50 (Reference
9 14). The solution technique contains two energy equations, a two-step numerics option, a gap
9 conductance model, constitutive models, and control and component system models. This code is used
9 for the blowdown simulation in Oconee large-break LOCA analyses.

9 CONTEMPT

9 The CONTEMPT code (Reference 16) as modified by Framatome Technologies, Inc., is used to calculate
9 the containment pressure following LOCA. The containment pressure is used as an input to the
9 RELAP5 blowdown analysis and the REFLOD3 refill and reflood analysis.

9 REFLOD3B

9 The REFLOD3B code (Reference 17) developed by Framatome Technologies, Inc., is used for simulation
9 of the refill and reflood periods of the large-break LOCA analysis. The program calculates flows, mass
9 and energy inventories, pressures, temperatures, and steam qualities along with variables associated with
9 the refilling of the reactor lower plenum and the recovery of the core.

9 BEACH

9 The BEACH code (Reference 18) developed by Framatome Technologies, Inc., is used for the prediction
9 of reflood heat transfer during the large-break LOCA analysis. It calculates the peak cladding temperature
9 and the local oxidation for comparison with the 10 CFR 50.46 (Reference 22) acceptance criteria.

9 CRAFT2

9 The CRAFT2 code (Reference 19) developed by Framatome Technologies, Inc., is used to calculate the
9 hydrodynamic behavior of the Reactor Coolant System during small-break LOCAs.

9 FOAM2

9 The FOAM2 code (Reference 20) developed by Framatome Technologies, Inc., is used to calculate the
9 core mixture level for small-break LOCAs that uncover the core.

9 THETA-1B

9 The THETA-1B code (Reference 21) as revised by Framatome Technologies, Inc., is used to calculate the
9 fuel pin thermal and mechanical response, including the peak cladding temperature for small-break
9 LOCAs.

9 BWC Critical Heat Flux Correlation

9 The BWC critical heat flux correlation (Reference 23) is used in the VIPRE-01 code to calculate the
9 DNBR for non-LOCA transient and accident analyses for fuel assemblies without mixing vane grids.

9 BWU-Z Critical Heat Flux Correlation

9 The BWU-Z critical heat flux correlation (Reference 24) is used in the VIPRE-01 code to calculate the
9 DNBR for non-LOCA transient and accident analyses for fuel assemblies with mixing vane grids.

9 BWU-N Critical Heat Flux Correlation

9 The BWU-N critical heat flux correlation (Reference 24) is used in the VIPRE-01 code to calculate the
9 DNBR for non-LOCA transient and accident analyses for fuel assemblies with mixing vane grids, but in
9 the lower part of the fuel assembly where there are no mixing vane grids. This correlation can also be
9 used for the steam line break DNBR analysis.

9 W-3S Critical Heat Flux Correlation

9 The W-3S critical heat flux correlation as programmed in the VIPRE-01 code (Reference 6) is used to
9 calculate the DNBR for the steam line break accident, when the core conditions are beyond the
9 correlation ranges for the other critical heat flux correlations.

9 15.1.4 INITIAL CONDITIONS

9 The generic initial conditions assumed in the transient and accident analyses are summarized in
9 Table 15-34 and referenced figures. These values have been selected to ensure that the results of each
9 analysis have an appropriate level of overall conservatism. Many of the initial conditions are determined
9 based on the nominal value of the plant parameter plus or minus the uncertainty associated with each
9 parameter. Parameters for which the uncertainty is included in the statistical DNBR limit are set to the
9 nominal value. Initial conditions which are not included in this table are provided in the detailed
9 description of each analysis.

9 15.1.5 SETPOINTS AND DELAY TIMES

9 The Reactor Protective System and Engineered Safeguards Protective System trip setpoints and delay
9 times are summarized in Table 15-35. The setpoints are based on the technical specification values, and
9 are either increased or decreased to account for setpoint drift depending on whether an earlier or later
9 reactor trip is conservative. Trip delay times account for instrument string delays and component delays,
9 such as the control rod gripper coil release delay.

9 15.1.6 REACTIVITY INSERTION FOLLOWING REACTOR TRIP

9 The reactivity insertion following reactor trip is a combination of a minimum available tripped rod worth
9 and a normalized insertion rate. The minimum available tripped rod worth assumed in safety analyses
9 must ensure, as a minimum, that the shutdown margin in the technical specifications is preserved. This
9 shutdown margin assumes that the most reactive rod remains in the fully withdrawn position and that the

other control rods drop from their power dependent insertion limits. The normalized reactivity insertion rate is determined by bounding control rod drop times as determined by plant testing, and by developing a conservative relationship between rod position and normalized reactivity worth.

15.1.7 DECAY HEAT

In the non-LOCA transients and accident analyses for which the post-trip decay heat is an important modeling consideration, the ANSI/ANS-5.1-1979 Standard (Reference 25) is used. The inputs to the calculation of the time-dependent decay heat per the ANS Standard are based on Oconee-specific core physics parameters. This modeling is implemented in the application of the RETRAN-02 code using either the built-in ANS standard with inputs to account for Oconee-specific core parameters, or as an input table of decay heat vs. time. The decay heat modeled by Framatome Technologies, Inc. in the LOCA analysis is 1.2 times the 1971 ANS Standard as required by 10 CFR 50 Appendix K (Reference 14).

15.1.8 SINGLE FAILURE AND LOSS OF OFFSITE POWER ASSUMPTIONS

A limiting active single failure in the Reactor Protective System or in the Engineered Safeguards is assumed. A single failure in the Emergency Feedwater System is also considered. A failure of the manual atmospheric dump valves is not considered. A loss of offsite power is only applied to the Section 15.13, "Steam Line Break Accident" steam line break accident, for which it is assumed to be lost at time zero, and for the Section 15.14, "Loss of Coolant Accidents" LOCA analyses.

15.1.9 CREDIT FOR CONTROL SYSTEMS AND NON-SAFETY COMPONENTS AND SYSTEMS

Control systems are generally assumed to respond as designed or remain in manual control (inactive), whichever assumption is more conservative. Non-safety components and systems are generally not credited in the analyses. The following are specific exceptions to the general modeling philosophy on control systems, and the situations where non-safety components and systems are credited in the analyses:

1. In the dropped rod event, the Integrated Control System will respond by initiating a plant runback to a reduced power level. Since this plant runback assists in the mitigation of the dropped rod event, no credit is taken for this control system design feature. This assumption is an additional conservatism that is not required by the methodology philosophy.
2. For a loss of all reactor coolant pumps without a loss of the Main Feedwater System, the Integrated Control System is credited for raising steam generator levels to the natural circulation setpoint. This design feature is implicitly credited in the loss of coolant flow event, and involves non-safety equipment. A failure of this design function would be mitigated manually by operator action to start the Emergency Feedwater (EFW) System.
3. The moderator dilution accident credits the non-safety high-flux-at-shutdown alarm and the control rod insertion limit alarm to alert the operator that a boron dilution event is in progress. Both of these alarms rely on non-safety equipment. The rod insertion alarm relies on the plant computer.
4. Many of the transient and accident analyses involve control rod movement. These analyses credit the normal withdrawal sequence, overlap, and rod speed, which are controlled by non-safety control systems.
5. For certain failures in the EFW System, credit is taken for realigning EFW flow through the non-safety MFW System.
6. Steaming of the steam generators with manual non-safety atmospheric dump valves is credited.

7. The turbine trip circuitry has two channels, one with a one second response time, and one with a fifteen second response time. The faster response time is credited in the methodology. The turbine trip circuitry is not completely safety-grade.
8. The capability to remotely throttle certain valves is credited. Some of the controls required to remotely throttle these valves are not safety-grade.
9. Electrical bus voltage and frequency control are credited. These are controlled by non-safety components.
10. The Integrated Control System trips both main feedwater pumps on a high steam generator level indication. A high level indication may occur following a main steam line break due to the pressure drops that result from the blowdown of the steam generator. Tripping of the main feedwater pumps will be assumed to occur in the steam line break analysis only if the plant response is more limiting.

15.1.10 ENVIRONMENTAL CONSEQUENCES CALCULATION METHODOLOGY

Environmental Consequences

A summary of the offsite doses is presented in Table 15-16. A description of each accident analysis is given in the appropriate section.

Fission Product Inventories

Inventory in the Core: End-of-cycle fission product inventories within the core are calculated by the ORIGEN-2 Code (Section 15.1, "Methodology," Ref. 27) using a data library for extended burnup cores (Section 15.1, "Methodology," Ref. 28), at the instant before shutdown. The core inventories are shown in Table 15-50.

Inventory in the Fuel Pellet Clad Gap: The fuel pin gap activities were determined using Regulatory Guide 1.25 (Section 15.1, "Methodology," Ref. 35) and Regulatory Guide 1.77 (Section 15.1, "Methodology," Ref. 36). Specifically, 10 percent of the iodine activities, 30 percent of the Kr-85 activity, and 10 percent of the remaining noble gas activities in the core are accumulated in the fuel-clad gap. The environmental consequences of the loss of coolant accident, control rod ejection accident, and fuel handing accidents are based on the assumption that the fission products in the gap between the fuel pellets and the cladding of the damaged fuel rods are released as a result of cladding failure. The core and associated gap inventories used for the LOCA, control rod cluster assembly ejection, and fuel handling accidents are shown in Table 15-50.

Inventory in the Reactor Coolant: The quantity of fission products released to the reactor coolant during steady state operation is based on the use of escape rate coefficients (sec^{-1}) derived from experiments involving purposely defected fuel elements. (Section 15.1, "Methodology," References 29 , 30, 31, 32) These coefficients represent the fraction of the activity in the fuel that is released, per unit time. Values of the escape rate coefficients used in the calculations are shown in Table 11-4.

Calculations of isotopic specific activities in the reactor coolant arising from steady-state fission product releases from the fuel (except for Kr-85) were performed with the Duke computer code PWR-SOURCE. The code calculates equilibrium reactor coolant fission product inventories and specific activities from the steady-state solutions to the differential equations for the radioactive decay chains for more than 150 isotopes. Due to the extremely long half life of Kr-85, an equilibrium activity level will not be reached in the reactor coolant during an operating cycle. For this particular isotope, the activity level is calculated from the exact solution of the decay chain, utilizing equilibrium activities of parent isotopes as inputs.

9 The reactor coolant activity levels are listed in Table 15-51.

9 *Inventory in the OTSGs and Secondary-Side Systems:* The concentration of the iodine isotopes in the
9 steam generators and secondary system coolant are assumed to be at the Technical Specification limit of
9 0.1 μCi/gm dose equivalent I-131, unless otherwise stated in a specific accident analysis. No credit is
9 taken for removal of iodine from the secondary coolant by station demineralizers.

9 The concentrations of noble gases in the secondary side coolant are assumed to be negligible, and
9 therefore are not modeled. Noble gases entering the secondary coolant system are continuously vented to
9 the atmosphere via the condenser off-gas system. Thus, there would be only very small quantities of these
9 gases within the secondary side coolant that could be released during an accident, and their contribution
9 to the overall whole body dose will be negligible.

9 Calculation of Accident Doses

9 The Code of Federal Regulations, Title 10, Part 100, Section 11 (Section 15.1, "Methodology," Ref. 34)
9 requires a dose consequence evaluation of postulated accidents resulting in fission product releases to the
9 environment. Two types of doses are calculated for purposes of analyzing these accidents: internal doses
9 to the thyroid resulting from inhalation of iodines and external whole body doses resulting from
9 submersion in noble gases and iodines.

9 Doses are calculated at two locations: the exclusion area boundary (EAB) and the outer boundary of the
9 low population zone (LPZ). Doses calculated at the EAB and LPZ are modeled as a receptor located in
9 a semi-infinite cloud of activity per Reg. Guide 1.109. (Section 15.1, "Methodology," Ref. 33).

9 15.1.11 RELOAD SAFETY EVALUATION

9 Each fuel reload cycle design is reviewed to determine if the values of the safety analysis physics
9 parameters assumed in the UFSAR Chapter 15, "Accident Analyses" licensing basis transient and
9 accident analyses remain valid. If the licensing basis assumptions remain bounding for the reload core,
9 then no additional actions are required. If the predicted values violate the licensing basis assumptions for
9 any of the key parameters, then reanalysis of the affected transients and accidents is required.

15.1.12 REFERENCES

9 9 1. UFSAR Chapter 15 Transient Analysis Methodology, DPC-NE-3005-PA, Revision 1, Duke Power, August 1999.

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9 9 3. B&W's Small-Break LOCA ECCS Evaluation Model, BAW-10154P, Babcock & Wilcox, November 1982.

9 9 4. Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000-PA, Revision 1, Duke Power, December 1997.

9 9 5. RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPRI, November 1988.

9 9 6. VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM, Revision 3, EPRI, August 1989.

9 9 7. CASMO-3: A Fuel Assembly Burnup Program User's Manual, NFA-88/48, Studsvik of America, September 1988.

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9 9. SIMULATE-3 Kinetics Theory and Model Description, SOA-96/26, Studsvik of America, April 1996.

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9 9 13. Thermal-Hydraulic Statistical Core Design Methodology, DPC-NE-2005-PA, Revision 1, Duke Power, November 1996.

9 14. Appendix K to Part 50 - ECCS Evaluation Models, Code of Federal Regulations, Volume 10.

9 9 15. RELAP5/MOD2-B&W - An Advanced Computer Program for Light Water Reactor LOCA and Non-LOCA Transient Analysis, BAW-10164P, Revision 3, B&W Nuclear Technologies, July 1996.

9 9 16. CONTEMPT - Computer Program for Predicting Containment Pressure, BAW-10095A, Rev. 1, Babcock & Wilcox, April 1978.

9 9 17. REFLOD3B - Model for Multinode Core Reflooding Analysis, BAW-10171P, Revision 2, Babcock & Wilcox, January 1989.

9 9 18. BEACH - A Computer Code for Reflood Heat Transfer During LOCA, BAW-10166P, Rev. 2, Babcock & Wilcox, September 1989.

9 9 19. CRAFT2 - FORTRAN Program for Digital Simulation of a Multinode Reactor Plant During Loss of Coolant, BAW-10092PA, Revision 3, Babcock & Wilcox, July 1985.

9 9 20. FOAM2 - Computer Program to Calculate Core Swell Level and Mass Flow Rate During Small-Break LOCA, BAW-10155A, Babcock & Wilcox, October 1987.

9 9 21. THETA1-B - A Computer Code for Nuclear Reactor Core Analysis, BAW-10094, Babcock & Wilcox, July 1974.

9 22. Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,
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9 23. BWC Correlation of Critical Heat Flux, BAW-10143-PA, Babcock & Wilcox, April 1985.

9 24. The BWU Critical Heat Flux Correlation, BAW-10199-PA, April 1996.

9 25. American National Standard for Decay Heat Power in Light Water Reactors, ANSI/ANS-5.1-1979,
9 American Nuclear Society, August 1979.

9 26. ARROTTA: Advanced Rapid Reactor Operational Transient Analysis, EPRI NP-7375-CCML, Rev.
9 1, EPRI, August 1993.

9 27. A. G. Croff, "A Users' Manual for the ORIGEN2 Computer Code," ORNL/TM-7175 (CCC-371),
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9 Effluents for the Purpose of Evaluating Compliance with 10CFR 50, Appendix I," Rev. 1, October
9 1977.

9 34. The Code of Federal Regulations, Title 10, Part 100, Section 11 (10CFR 100.11), "Determination of
9 Exclusion Area, Low Population Zone, and Population Center Distance."

9 35. Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences
9 of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized
9 Water Reactors (Safety Guide 25)," March 1972.

9 36. Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for
9 Pressurized Water Reactors," May 1974.

15.2 STARTUP ACCIDENT

8 15.2.1 IDENTIFICATION OF CAUSE AND DESCRIPTION

8 The startup accident is an uncontrolled withdrawal of a control rod group from a zero power initial
8 condition. It is caused by an operator error or a malfunction in the Rod Control System and can result in
8 a nuclear power excursion. Since the heat removal capability of the secondary system is not increased
8 during the power excursion, the resultant power mismatch would cause an increase in the Reactor
8 Coolant System (RCS) and secondary system temperatures and pressures. The control rod motion would
8 also cause the core power peaking to change. The reactor would be expected to trip on high flux or high
8 RCS pressure.

8 The startup accident is analyzed from a hot zero power beginning-of-cycle condition, with three reactor
8 coolant pumps (RCPs) in operation. The maximum control rod withdrawal rate is assumed. The system
8 analysis determines the transient peak RCS pressure, and the transient core boundary conditions for the
8 detailed core thermal-hydraulic analysis. In the peak RCS pressure analysis, the pressurizer spray and the
8 pressurizer PORV are assumed to be inoperable. The pressurizer code safety valves (PSVs) are modeled
8 using conservative assumptions for drift, blowdown, and valve capacity that minimize relief flow. The
8 analysis methodology and the computer codes used in the analysis are given in Table 15-33. The initial
8 conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards
8 Protective System setpoints and delay times are given in Table 15-35.

8 The reactivity addition rate assumed in the analysis is based on control rod group overlap, rod speed, and
8 withdrawal sequence, which are controlled by non-safety systems. The loop with two RCPs in operation
8 will indicate a lower hot leg pressure than the loop with only one active RCP. Therefore, the analysis
8 assumes a single failure of one of the narrow range pressure channels on the loop with only one active
8 RCP. This requires the high pressure reactor trip to be generated by the loop with a lower RCS pressure,
8 which is conservative since it will delay reactor trip.

8 The startup accident is considered to be a fault of moderate frequency. The acceptance criteria for this
8 accident are that the peak RCS pressure does not exceed 110% (2750 psig) of the design pressure, and
8 that the minimum DNBR remains above the 1.50 design limit.

8 15.2.2 ANALYSIS

8 The startup accident analysis assumes three RCPs in operation and a maximum control rod withdrawal
8 rate of 11.5 pcm/sec. The analysis duration of 100 seconds is sufficient to demonstrate the peak thermal
8 power and peak RCS pressure. The analysis results are shown in Figure 15-1 through Figure 15-6, and
8 the sequence of events is given in Table 15-36. Figure 15-1 shows the neutron power and thermal power
8 transients. Neutron power does not begin to appreciably increase until the inserted reactivity begins to
8 approach one dollar at approximately 45 seconds. Reactor trip occurs on high RCS pressure at 51.8
8 seconds with neutron power at approximately 125%. The thermal power rises to a peak value of 73% at
8 52 seconds. Since the peak core thermal power remains less than the permissible power level (75%) with
8 three RCPs in operation, DNB is not a concern for this transient, and a detailed core thermal-hydraulic
8 analysis is not necessary. Figure 15-2 shows the reactivity response. The reactivity insertion rate due to
8 rod withdrawal is constant until reactor trip. Fuel heatup causes negative reactivity insertion due to
8 Doppler temperature feedback until reactor trip. System heatup prior to reactor trip causes the moderator
8 temperature to increase, which inserts positive reactivity due to the assumed positive moderator
8 temperature coefficient of reactivity. Figure 15-3 and Figure 15-4 show the cold leg and hot leg

8 temperature transients. Because of the reduced flow due to the inactive RCP, the temperature response in
8 the loop with the inactive RCP is delayed. After reactor trip and the opening of the PSVs, the
8 temperatures in both loops decrease. Figure 15-5 shows the pressurizer level response. During the
8 thermal power excursion level rises rapidly due to the insurge of liquid into the pressurizer. After reactor
8 trip and the opening of the PSVs, the pressurizer level rises more slowly and then stabilizes. Figure 15-6
8 shows the RCS pressure as a function of time. RCS pressure rises to a maximum value of approximately
8 2660.4 psig at 54.3 seconds, and then decreases due to PSV lift. The peak RCS pressure of 2746.9 psig
8 occurs at the bottom of the reactor vessel.

8 15.2.3 CONCLUSIONS

8 The startup accident results in a peak core thermal power of 73%. Since this power level is below the
8 permissible steady-state power level with three RCPs in operation, DNB is not a concern for this
8 transient. The peak RCS pressure for this transient is 2746.9 psig. All of the acceptance criteria are met.

9 15.3 ROD WITHDRAWAL AT POWER ACCIDENT

9 15.3.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

9 The rod withdrawal at power accident is caused by an operator error or a failure in the Rod Control
9 System which results in an uncontrolled withdrawal of a control rod group while the reactor is at power.
9 The rod withdrawal causes a nuclear power excursion and a resultant heatup and pressurization of the
9 Reactor Coolant System (RCS). The expected plant response to a rod withdrawal event would include
9 the following. Feedwater flow would follow the increase in reactor power, thereby maintaining adequate
9 RCS heat removal until the reactor is tripped on high flux or flux/flow/imbalance. Following reactor trip,
9 the Turbine Bypass System (TBS) and main steam code safety valves would relieve steam in order to
9 control the post-trip steam generator pressures. RCS pressure would be controlled by the pressurizer
9 spray, PORV, and heaters. In addition, feedwater would be automatically controlled to maintain the
9 post-trip steam generator level.

9 Separate analyses are performed to investigate the peak RCS pressure and the core cooling capability
9 following the rod withdrawal event. The core cooling analysis covers a spectrum of initial power levels
9 that bounds the range of permissible power levels given the number of operating reactor coolant pumps
9 (RCPs). Four and three RCPs in operation are considered. Initial power levels below 15% are assumed
9 to be bounded by the startup accident. In the peak RCS pressure analysis, the pressurizer spray,
9 pressurizer PORV, and the Turbine Bypass System are assumed to be inoperable. In addition, the
9 pressurizer and main steam code safety valves are modeled using conservative assumptions for drift,
9 blowdown, and valve capacity that minimize relief flow. Both the peak RCS pressure and the core
9 cooling analyses hold main feedwater and main steam flow rates constant prior to reactor trip. The
9 analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial
9 conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards System
9 setpoints and delay times are given in Table 15-35.

9 The reactivity addition rates assumed in the analyses are bounded by minimum and maximum values
9 which are calculated based on control rod group overlap, rod speed, and withdrawal sequence, which are
9 controlled by non-safety systems. No single failure has been identified which adversely impacts the results
9 of the cases initiated from four RCP operation. For the cases initiated from three RCP operation, the
9 analysis assumes a single failure of one of the narrow range pressure channels on the loop with only one
9 active RCP. This requires the high pressure reactor trip to be generated by the loop with a lower RCS
9 pressure, which is conservative since it will delay reactor trip.

9 The rod withdrawal at power accident is considered to be a fault of moderate frequency. The acceptance
9 criteria for this accident are that the minimum DNBR remains above the 1.50 design limit and the peak
9 RCS pressure does not exceed 110% (2750 psig) of design pressure.

9 15.3.2 PEAK RCS PRESSURE ANALYSIS

9 The limiting peak RCS pressure case assumes a full power initial condition and a withdrawal rate
9 equivalent to 2.4 pcm/sec. Since the maximum RCS pressure is expected to occur near the time of
9 reactor trip, the analysis duration is 10 seconds following the reactor trip. The transient response for this
9 limiting case is shown in Figure 15-11, Figure 15-12, Figure 15-13, and Figure 15-14 and the sequence of
9 events is given in Table 15-37. Neutron power (Figure 15-11) increases at a constant rate until the
9 reactor trips on high RCS pressure at about 39 seconds. Since the reactivity insertion is fairly slow, the
9 thermal power essentially stays in equilibrium with the neutron power prior to reactor trip. RCS hot and

9 cold leg temperatures are given in Figure 15-12. The cold leg temperature increases gradually prior to trip
9 and then increases rapidly following the turbine trip due to increasing saturation temperature in the steam
9 generators. Hot leg temperatures increase both due to the rising cold leg temperatures and due to the
9 increasing reactor power. Pressurizer level (Figure 15-13) increases steadily as the RCS heats up, expands,
9 and causes an insurge into the pressurizer. The RCS pressure response (Figure 15-14) essentially mirrors
9 the pressurizer level, with a peak value reached at about 43 seconds. At this point, a peak pressure of
9 2611.5 psig is reached at the bottom of the reactor vessel.

9 15.3.3 CORE COOLING CAPABILITY ANALYSIS

9 The limiting DNBR case assumes a full power initial condition and a withdrawal rate equivalent to 1.0
9 pcm/sec. The transient response for this limiting case is shown in Figure 15-15, Figure 15-16,
9 Figure 15-17, Figure 15-113, and Figure 15-114, and the sequence of events is given in Table 15-38.
9 While the trends are very similar to those shown in the peak RCS pressure case, the duration of the
9 analysis is much longer due to a significantly lower reactivity insertion rate. Since the minimum DNBR
9 occurs near the time of reactor trip, the analysis duration is 10 seconds following the reactor trip. In order
9 to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic
9 analysis. Neutron power and thermal power (Figure 15-15) increase at a constant rate until the reactor
9 trips on high RCS pressure at about 148 seconds. RCS hot and cold leg temperatures are given in
9 Figure 15-16. The cold leg temperature increases gradually prior to trip and then increases rapidly
9 following the turbine trip due to increasing saturation temperature in the steam generators. Hot leg
9 temperatures increase both due to the rising cold leg temperatures and due to the increasing reactor power.
9 Pressurizer level (Figure 15-17) increases steadily as the RCS heats up, expands, and causes an insurge
9 into the pressurizer. The RCS pressure response (Figure 15-113) essentially mirrors the pressurizer level,
9 although the increase is suppressed by pressurizer spray. The transient minimum DNBR (Figure 15-114)
9 of 1.719 occurs at 148 seconds.

9 15.3.4 CONCLUSIONS

9 The rod withdrawal at power accident results in a peak RCS pressure of 2611.5 psig. The minimum
9 DNBR is determined to be 1.719. All of the acceptance criteria are met.

15.4 MODERATOR DILUTION ACCIDENTS

9 15.4.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

9 A moderator dilution accident occurs when the soluble boric acid concentration of makeup water supplied
9 to the Reactor Coolant System (RCS) is less than the concentration of the existing reactor coolant, and
9 the water is injected in an uncontrolled manner. The cause of such an event can be attributed to any one
9 of a number of failure modes in the systems that are capable of supplying unborated water to the RCS.
9 With the reactor initially at power, control rods would insert to offset the reduction in RCS boron
9 concentration. The operator would be alerted by the control rod insertion and terminate the event by
9 identifying the dilution source and isolating it. In the refueling mode the operator would be alerted to the
9 moderator dilution event by the high-flux-at-shutdown alarm. In response to this alarm the operator
9 would identify the source of the dilution event and isolate it.

9 The moderator dilution accident is analyzed at the initial conditions of beginning-of-cycle power operation
9 (Mode 1) with the Integrated Control System (ICS) in either the automatic or manual mode, and in the
9 refueling mode (Mode 6). Manual operator action is relied on to terminate the dilution in both modes.
9 Mode 1 is analyzed to demonstrate that there is adequate time for the operator to terminate the dilution
9 when maximum dilution source flowrates are assumed. Mode 6 is analyzed assuming administrative
9 controls on potential dilution sources such that the results of the accident analysis give exactly a 30
9 minute operator response time. Flowrates are restricted through administrative controls to values that are
9 less than these analyzed flowrates. Mitigation of the event is not credited until an alarm is received. In
9 Mode 1 with the ICS in manual, mitigation does not begin until reactor trip occurs. This conservatively
9 ignores any other alarms or indications of the increase in reactor power, pressurizer level, and RCS
9 pressure. In Mode 1 with the ICS in automatic, mitigation of the event does not begin until the rod
9 withdrawal limit alarm actuates. This conservatively ignores the indications of the control rods inserting
9 to control the power level and temperature. In Mode 6 mitigation of the event does not begin until the
9 source range high-flux-at-shutdown alarm actuates. The analysis assumes conservatively high dilution
9 flowrates, high initial boron concentrations, and small mixing volumes. The moderator dilution accident
9 potentially results in a loss of shutdown margin and an inadvertent criticality, approaching the DNBR
9 limit, or challenging the peak RCS pressure limit. This accident is conservatively analyzed to ensure that
9 the operator terminates the boron dilution prior to exceeding these criteria.

9 As discussed in the preceding paragraph, alarm actuation is credited for alerting the operator that a boron
9 dilution event is in progress. Both the rod withdrawal limit alarm and the high-flux-at-shutdown alarm
9 rely on non-safety equipment. No single failure has been identified that would prevent the operators from
9 successfully isolating the possible dilution sources and terminating the accident.

9 The moderator dilution accident is considered to be a fault of moderate frequency. The acceptance
9 criteria for manual operator action to terminate the dilution event are 15 minutes during Mode 1 and 30
9 minutes during Mode 6 following the actuation of the alarm credited for alerting the operator of the event.
9 The Mode 6 analysis also requires administrative controls to limit the flowrate from unborated water
9 sources. By meeting these operator action times and preventing core re-criticality, it is assured that the
9 plant response will not approach the DNBR limit or the peak RCS pressure limit.

9 15.4.2 FULL POWER INITIAL CONDITION ANALYSIS

9 <u>Mode 1 With ICS in Automatic</u>

9 A conservative upper bound on the dilution flowrate of 300 gpm of unborated water is assumed, which is
9 the design capacity of two bleed transfer pumps. At this flowrate re-criticality would not occur until 17.2
9 minutes following the rod withdrawal limit alarm which alerts the operator. Therefore there is sufficient
9 time for the operator to terminate the dilution event.

9 Mode 1 With ICS in Manual

9 A conservative upper bound on the dilution flowrate of 300 gpm of unborated water is assumed, which is
9 the design capacity of two bleed transfer pumps. At this flowrate re-criticality would not occur until 15.6
9 minutes following the reactor trip alarm which alerts the operator. Therefore there is sufficient time for
9 the operator to terminate the dilution event.

9 15.4.3 REFUELING INITIAL CONDITION ANALYSIS

9 Given the maximum allowed operator action time of 30 minutes, the maximum flowrate from the bleed
9 transfer pumps must be less than 62 gpm.

9 15.4.4 CONCLUSIONS

9 Three moderator dilution accident cases were performed corresponding to Mode 1 with the ICS in
9 automatic, Mode 1 with the ICS in manual, and Mode 6. The Mode 1 analyses calculate 17.2 minutes
9 and 15.6 minutes operator action times for the ICS in automatic and manual cases, respectively. The
9 Mode 6 analysis calculates a maximum bleed transfer pump flowrate of less than 62 gpm in order to meet
9 the 30 minute operator action time. The 62 gpm limit is controlled administratively in Mode 6. All of
9 the acceptance criteria are met.

15.5 COLD WATER ACCIDENT

15.5.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

The cold water accident is caused by an inadvertent startup of the fourth reactor coolant pump (RCP) from an initial three RCP operating condition. The increase in core flow as a result of the fourth RCP starting causes a decrease in the core average temperature. If the moderator temperature coefficient of reactivity is negative, an insertion of positive reactivity and an increase in reactor power will occur. Administrative controls limit the power level at which the fourth RCP can be started to less than 50% power. The normal plant response to this event would be for the Integrated Control system (ICS) to insert control rods in an attempt to maintain the initial power level.

The cold water accident is analyzed from an 80% power end-of-cycle initial condition. A conservative RCP start time is assumed. The system analysis determines the transient core boundary conditions for the detailed core thermal-hydraulic analysis. It is assumed that rod control is in manual and the pressurizer heaters are inoperable. The pump control circuitry interlock that prevents startup of an idle pump if the power is above 50 percent full power is assumed to be inoperable. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

No single failure has been identified which adversely affects this accident.

The cold water accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the 1.50 design limit, and the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. Since this event results in a minor RCS pressurization that does not approach the limit, only the minimum DNBR acceptance criterion is of concern.

15.5.2 ANALYSIS

The cold water accident analysis results are shown in Figure 15-18, Figure 15-115, Figure 15-116, Figure 15-117 and Figure 15-118 and the sequence of events is given in Table 15-39. Since the minimum DNBR occurs near the time the RCP has come up to speed, the analysis is terminated 11 seconds after the RCP achieves full speed. Following the start of the fourth RCP, RCS flow (Figure 15-18) rapidly increases to full flow, resulting in a decrease in the core average temperature (Figure 15-115). Neutron power and thermal power (Figure 15-116) increase during this time period due to the positive reactivity insertion from the decrease in the core average temperature, and reach maximum values of 108.4% and 96.7%, respectively. No reactor trip setpoints are exceeded. A combination of Doppler feedback and increasing RCS cold leg temperatures (Figure 15-117) after the pump has reached full speed stop the power excursion, with power returning to its initial condition by the end of the analysis. The RCS pressure response (Figure 15-118) reaches a pressure of only 2165 psig during the simulation. Since the maximum thermal power that occurs during this event is less than 100% full power, and the other core conditions are relatively close to nominal full power conditions, DNB is not a concern during this event.

9 ## 15.5.3 CONCLUSIONS

9 The results of the cold water accident demonstrate that since the maximum power level remains less than
9 100%, the minimum DNBR remains well above the limit. The RCS pressure transient does not
9 approach the peak RCS pressure limit. All of the acceptance criteria are met.

15.5.4 REFERENCES

6 1. Deleted per 1996 Update

9 2. Deleted per 1999 Update

9 3. Deleted per 1999 Update

15.6 LOSS OF COOLANT FLOW ACCIDENTS

15.6.1 IDENTIFICATION OF CAUSE AND DESCRIPTION

A loss of coolant flow accident occurs if one or more of the reactor coolant pumps (RCPs) stops due to a loss of electrical power or a mechanical failure. The loss of coolant flow accident resulting from an electrical failure results in one or more RCPs coasting down. The limiting loss of coolant flow accident resulting from a mechanical failure is a locked rotor in one pump. If the reactor is at power at the time of the accident, the immediate effect of a loss of coolant flow is a rapid increase in the core coolant temperature. This temperature increase could result in approaching DNB with subsequent fuel damage if the reactor is not tripped promptly. During the loss of coolant flow accident, the Reactor Protective System (RPS) will trip the reactor on the flux/flow/imbalance trip, or on the pump monitor trip. If all RCPs trip, the plant transitions to the natural circulation mode of core cooling.

During a RCP coastdown event, the flux/flow/imbalance trip function trips the reactor when the setpoint is reached, and the pump monitor trip trips the reactor when any two of the four RCPs trip if the reactor power is greater than 2%. The pump monitor trip function has only one channel per pump. Therefore, assuming a single failure of the pump monitor trip on one pump, the possible RCP coastdown events with four or three RCPs in operation are determined. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis. Since some of the RCP coastdown events are bounded by others, only the following five RCP coastdown events are analyzed. Results for Cases 2, 3, and 4 are presented since they bound the other cases.

Case	RCP Coastdown*	Power Level (%)	Trip Function
1	4/1	100	flux/flow
2	4/2**	100	flux/flow
3	4/4	100	pump monitor
4	3/1**	80	flux/flow
5	3/3	80	pump monitor

Note:

* 4/1 means 1 RCP coasting down with 4 RCPs in operation

** The RCP(s) coasting down can be in the same loop or in different loops

For the locked rotor accident analysis a single failure in the pump monitor trip is assumed for both four and three RCPs in operation. Therefore, the flux/flow/imbalance trip provides DNB protection for the locked rotor event. With three RCPs in operation, a locked rotor in the loop with both RCPs operating is the limiting case. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis.

The analysis methodology and the computer codes used in the loss of flow accident analyses are given in Table 15-33. The initial conditions are given in Table 15-34. Beginning-of-cycle conditions are limiting. The RPS and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

A single failure in the pump monitor trip function is assumed in the loss of flow accident analyses. This failure results in relying on the flux/flow/imbalance trip function to trip the reactor in most of the

analyzed cases. The RCS will transition to the natural circulation cooling mode if all RCPs have stopped. Natural circulation is then established by raising steam generator levels to the natural circulation setpoint. If the Main Feedwater System is in operation, the increase in steam generator levels is controlled by the non-safety Integrated Control System. Otherwise, the Emergency Feedwater System actuates and the safety-grade Emergency Feedwater Control System controls the steam generator level to the natural circulation setpoint.

The RCP coastdown accidents are considered to be faults of moderate frequency (fewer than all RCPs coast down) or infrequent fault (all RCPs coast down) events. The acceptance criterion for all RCP coastdown accidents is that the minimum DNBR remains above the design limit. The DNBR design limit for each accident is identified in the analysis results discussion. The RCP locked rotor accident is categorized as a limiting fault. The acceptance criteria for the RCP locked rotor accident are that any fuel damage calculated to occur must be of a sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability, that the peak RCS pressure does not exceed 110% (2750 psig) of the design pressure, and that the calculated offsite doses are less than 100% of the 10CFR Part 100 limits. To evaluate the third criterion on offsite doses, the extent of fuel failures are quantified with the assumption that any fuel pin that exceeds the DNB limit is considered failed. The fuel failure results are then used in the offsite dose calculations to verify that the offsite dose criteria are satisfied. The results of the locked rotor analysis demonstrates that the peak RCS pressure limit is not challenged.

15.6.2 FOUR RCP COASTDOWN FROM FOUR RCP INITIAL CONDITIONS ANALYSIS

The 4/4 RCP coastdown accident analysis results are shown in Figure 15-19, Figure 15-20, Figure 15-21, Figure 15-22, Figure 15-23, and Figure 15-24, and the sequence of events is given in Table 15-40. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 19 seconds. The flow in both loops (Figure 15-19) behaves identically since the 4/4 RCP coastdown event is essentially symmetrical. The loop flows decrease towards zero flow during the transient. Prior to control rod motion, the neutron power (Figure 15-20) has already decreased due to the negative moderator temperature feedback as a result of the increase in the core coolant temperature. The pump monitor trip function trips the reactor at 0.61 seconds. The core thermal power (Figure 15-20) follows the trend of the neutron power with a thermal delay. The hot and cold leg temperatures (Figure 15-21) change only slightly in response to the change in flow during the transient. The pressurizer level (Figure 15-22) increases due to the increase in the RCS average temperature, and then decreases following the reactor trip. RCS pressure (Figure 15-23) increases initially due to the increase in pressurizer level, and decreases post-trip. The transient minimum DNBR (Figure 15-24) of 1.93 occurs at 1.6 seconds, which is greater than the design limit of 1.50.

15.6.3 TWO RCP COASTDOWN FROM FOUR RCP INITIAL CONDITIONS ANALYSIS

The results of the 4/2 RCP coastdown accident analysis with the tripped RCPs in the same loop are presented since it is the bounding event for the four RCP initial conditions. The results are shown in Figure 15-25 and Figure 15-119, Figure 15-120, Figure 15-121, Figure 15-122, Figure 15-123, and the sequence of events is given in Table 15-41. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 19 seconds. The transient behavior of many of the key parameters trend those of the 4/4 RCP coastdown accident. The flux/flow imbalance trip function trips the reactor at 4.71 seconds. The core flow (Figure 15-25) decreases after the RCPs trip, and approaches the equilibrium two RCP flowrate at the end of the analysis. The faulted loop flow decreases toward zero flow, while the intact loop flow increases from its initial value. The hot leg temperatures (Figure 15-120) change only slightly in response to the change in flow during the transient. The cold leg temperatures in

the affected loop decrease due to the decrease in primary flow, and then increase due to the post- trip increase in steam pressure. The cold leg temperatures in the unaffected loop initially remain stable and then increase due to the flow reversal in the loop. The transient minimum DNBR (Figure 15-123) of 1.69 occurs at 5.3 seconds, which is equal to the design limit of 1.69.

15.6.4 ONE RCP COASTDOWN FROM THREE RCP INITIAL CONDITIONS ANALYSIS

The results of the 3/1 RCP coastdown accident analysis with the tripped RCP in the same loop as the initially idle RCP are presented since it is the bounding event for the three pump initial conditions. The results are shown in Figure 15-124, Figure 15-125, Figure 15-126, Figure 15-127, Figure 15-128, and Figure 15-129 and the sequence of events is given in Table 15-42. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 19 seconds. The transient behavior of many of the key parameters trend those of the 4/2 RCP coastdown accident. The flux/flow imbalance trip function trips the reactor at 4.25 seconds. The RCS flow transient (Figure 15-124) approaches the two RCP equilibrium flowrate at the end of the analysis. While the affected loop flow decreases and reverses direction, the intact loop flow increases from its initial value. The transient minimum DNBR (Figure 15-129) of 2.02 occurs at 4.8 seconds, which is greater than the design limit of 1.77.

15.6.5 LOCKED ROTOR FROM FOUR RCP INITIAL CONDITIONS ANALYSIS

The locked rotor accident from four RCP initial conditions analysis results are shown in Figure 15-130, Figure 15-131, Figure 15-132, Figure 15-133, Figure 15-134, and Figure 15-135, and the sequence of events is given in Table 15-43. Since the transient minimum DNBR occurs near the time of reactor trip, the analysis is terminated at 9 seconds. The core flow (Figure 15-130) rapidly decreases after the locked rotor occurs, and approaches the equilibrium three RCP flowrate at the end of the analysis. The locked rotor cold leg flow rapidly decreases to a negative value, and the other cold leg flow increases towards the three RCP flowrate. Prior to reactor trip, the neutron power (Figure 15-131) has already decreased due to the negative moderator temperature feedback as a result of the increase in core coolant temperature. The flux/flow trip function trips the reactor at 1.71 seconds. The core thermal power (Figure 15-131) follows the trend of the neutron power with a thermal delay. The hot leg temperatures (Figure 15-132) increase initially due to the decrease in flow. After the reactor trips, the hot leg temperatures begin to decrease. The cold leg temperature in the affected loop decreases slightly due to the decrease in primary flow. The cold leg temperature of the unaffected loop remains stable initially, and then increases post-trip due to the increase in steam pressure. The pressurizer level (Figure 15-133) increases initially due to the increase in RCS temperatures, and then decreases post-trip. The RCS pressure response (Figure 15-134) trends with the change in pressurizer level. The transient minimum DNBR (Figure 15-135) of 1.50, which occurs at 2.1 seconds, is less than the design limit of 1.61. Consequently, DNBR margin may not exist, and a fuel pin census analysis is performed to determine if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. A range of pin radial peaks and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel pin in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the DNBR limit is exceeded. All fuel pins that exceed the DNBR limit are assumed to experience cladding failure and are counted in the source term for the offsite dose calculation. The results of the fuel pin census analysis for the locked rotor accident from four RCP initial conditions is that DNBR margin exists for all of the fuel pins. Due to no fuel failures, the offsite dose consequences for the locked rotor accident are bounded by the offsite dose consequences for the steam line break accident.

The peak maximum RCS pressure is 2452 psig, which is well below 110% of the design pressure (2750 psig).

15.6.6 LOCKED ROTOR FROM THREE RCP INITIAL CONDITIONS ANALYSIS

The locked rotor accident from three RCP initial conditions analysis results are shown in Figure 15-136, Figure 15-137, Figure 15-138, Figure 15-139, Figure 15-140, and Figure 15-141, and the sequence of events is given in Table 15-44. Since the transient minimum DNBR occurs near the time of reactor trip, the analysis is terminated at 9 seconds. The analysis results are similar to those of the four RCP initial condition analysis. The flows in the unaffected loop and the core (Figure 15-136) approach the two RCP equilibrium flowrates at the end of the analysis. The transient minimum DNBR (Figure 15-141) of 1.33, which occurs at 2.2 seconds, is less than the design limit of 1.62. Consequently, DNBR margin does not exist, and a fuel pin census analysis is performed. The results of the fuel pin census analysis for the locked rotor accident from three RCP initial conditions is that DNBR margin exists for all of the fuel pins. Due to no fuel failures, the offsite dose consequences for the locked rotor accident are bounded by the offsite dose consequences for the steam line break accident.

15.6.7 NATURAL CIRCULATION CAPABILITY ANALYSIS

The natural circulation capability analysis determines the stable natural circulation flowrates for a range of post-trip decay heat values. The natural circulation flowrates are shown to be greater than the decay heat power levels on a percentage basis, thereby limiting the temperature rise across the core to less than that at full power conditions. Therefore, adequate core cooling will be maintained during natural circulation.

Decay Heat Power (MW_{th})	(% Power)	Natural Circulation Flowrate (% Full Flow)	Time After Reactor Trip (sec)
80	3.1	3.9	120
70	2.7	3.7	240
60	2.3	3.5	540
50	1.9	3.3	1,200
40	1.6	3.0	2,110
30	1.2	2.7	5,520
20	0.8	2.4	26,400
10	0.4	1.9	280,800

15.6.8 ENVIRONMENTAL CONSEQUENCES

The radiological consequences of a locked rotor accident are bounded by the consequences of the large main steam line break accident.

15.6.9 CONCLUSIONS

The results of the RCP coastdown accident analyses show that the limiting RCP coastdown event is two RCPs coasting down from a four RCP initial condition. The minimum DNBR result of 1.69 is equal to the DNBR limit of 1.69. The results of the locked rotor accident analyses show that the limiting locked rotor event is from a three RCP initial condition. The results of a pin census analysis for the locked rotor show that DNBR margin exists for all of the fuel rods. Therefore, no fuel rod failures are assumed in the offsite dose analysis. The results of the locked rotor analysis demonstrate that the peak RCS pressure limit is not challenged. The results of the natural circulation capability analysis show adequate flow for core cooling and decay heat removal by natural circulation after all RCPs trip. All of the acceptance criteria are met.

15.6.10 REFERENCES

9 1. Deleted per 1999 Update
9 2. Deleted per 1999 Update
9 3. Deleted per 1999 Update
9 4. Deleted per 1999 Update
9 5. Deleted per 1999 Update
9 6. Deleted per 1999 Update

15.7 CONTROL ROD MISALIGNMENT ACCIDENTS

9 15.7.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

9 Control rods are normally grouped into patterns which maintain a symmetric core power distribution. A
9 mechanical or electrical failure can cause a control rod to become misaligned from its group, causing an
9 asymmetric reactivity distribution and, if the control rod is stuck, a reduction in the total available control
9 rod worth for shutdown of the reactor. Three modes of misalignment can occur. The first mode, the
9 statically misaligned rod accident, occurs during withdrawal or insertion of a control rod group when one
9 rod becomes stuck at some position as the rod group continues in motion. This condition will affect the
9 power distribution in the core and could lead to excessive power peaking. The second mode of
9 misalignment, the stuck rod accident, can occur on reactor trip if one rod fails to insert. This condition
9 requires an evaluation to determine that sufficient negative reactivity is available for tripping the reactor
9 when considering the maximum worth stuck rod. The third mode, the dropped rod accident, can occur
9 when one rod drops partially or fully into the core. The resulting plant transient response is a rapid
9 reduction in power and a possible subsequent increase in power due to a negative moderator coefficient of
9 reactivity. The expected plant response is that the Integrated Control System (ICS) will respond to an
9 indicated dropped control rod by initiating a power runback and by inhibiting control rod withdrawal. A
9 reactor trip may occur on variable low pressure-temperature for some dropped rod accidents.

9 For the statically misaligned rod accident, the core designs are evaluated to confirm that the resulting core
9 power distribution is acceptable. For the stuck rod accident, each core design is required to be capable of
9 maintaining a 1% $\Delta k/k$ shutdown margin at hot shutdown conditions with the assumption of the
9 maximum worth rod stuck in the fully withdrawn position. The dropped rod accident is analyzed for a
9 set of dropped rod worths for initial conditions of 100% power with four reactor coolant pumps (RCPs)
9 in operation, and for 80% power with three RCPs in operation. Physics parameters for both
9 beginning-of-cycle (BOC) and end-of-cycle (EOC) conditions are analyzed. The expected action taken by
9 the ICS on indication of a dropped rod is to inhibit control rod withdrawal and to run back power
9 demand to 55 percent of rated load at 1 percent per minute. This non-safety action by the ICS is not
9 credited in the analysis. The ICS is assumed to respond to the decrease in reactor power by withdrawing
9 control rods to meet the load demand, which is a conservative assumption. A reactor trip on high
9 pressure or flux/flow/imbalance may occur for some cases. The system analysis determines the transient
9 core boundary conditions for the detailed core thermal-hydraulic analysis. The analysis methodology and
9 the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in
9 Table 15-34. The Reactor Protective System (RPS) and Engineered Safeguards Protective System
9 setpoints and delay times are given in Table 15-35.

9 Due to the asymmetric core power distribution resulting from the dropped rod, the excore power range
9 flux channels which input to the RPS high flux trip function will indicate different transient power
9 responses. The limiting single failure for the dropped rod analysis is the excore power range flux channel
9 adjacent to the quadrant with the highest indicated core power level. This assumption results in the third
9 highest excore flux channel determining whether the high flux trip setpoint is reached based on the 2/4
9 RPS logic design.

9 The three identified modes of control rod misalignment accidents are considered to be faults of moderate
9 frequency. The acceptance criteria for these accidents are that the minimum DNBR remains above the
9 1.50 limit, that the centerline fuel melt limit is not exceeded, and that the peak RCS pressure does not
9 exceed 110% (2750 psig) of design pressure. Since this event results in a minor RCS pressurization which

9 does not approach the limit, only the minimum DNBR and centerline fuel melt acceptance criteria are of
9 concern.

9 15.7.2 DROPPED ROD ANALYSIS

9 The limiting dropped rod accident is a 20 pcm dropped rod from full power at BOC conditions. The
9 duration of the analysis is 60 seconds, which is sufficient for the time of minimum DNBR. The transient
9 response is shown in Figure 15-26, Figure 15-27, Figure 15-28, Figure 15-143 and Figure 15-144, and
9 the sequence of events is given in Table 15-45. The initial decrease in reactor power (Figure 15-26) is
9 caused by the reactivity inserted by the dropped rod. The ICS response, due to the asymmetric power
9 distribution, causes control rods to be withdrawn and results in an increase in reactor power. Hot and
9 cold leg temperatures (Figure 15-27) increase at a steady rate due to the power mismatch between reactor
9 power and steam generator heat removal. The trends of pressurizer level (Figure 15-28) and RCS
9 pressure (Figure 15-143) reflect this power mismatch. The maximum RCS pressure is 2333 psig. The
9 transient minimum DNBR (Figure 15-144) of 1.672 occurs at about 23.5 seconds.

9 15.7.3 STATICALLY MISALIGNED ROD ANALYSIS

9 The results of the generic evaluation of the statically misaligned rod event show that this event is bounded
9 by the dropped rod event.

9 15.7.4 CONCLUSIONS

9 The stuck rod accident cannot result in insufficient negative reactivity insertion on reactor trip due to the
9 core design criteria. The statically misaligned rod accident has been shown to be bounded by the dropped
9 rod accident. The minimum DNBR is determined to be 1.672. No fuel centerline melt is predicted. The
9 RCS pressure transient does not approach the peak primary pressure limit. All of the acceptance criteria
9 are met.

15.7.5 REFERENCES

9 1. Deleted per 1999 Update

9 2. Deleted per 1999 Update

9 3. Deleted per 1999 Update

9 4. Deleted per 1999 Update

15.8 TURBINE TRIP ACCIDENT

15.8.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

The turbine trip accident is caused by events including a generator trip, low condenser vacuum, loss of turbine lubrication oil, turbine thrust bearing failure, turbine overspeed, main feedwater pump trip, high steam generator level, or a reactor trip. The rapid closure of the main turbine stop valves results in a rapid increase in the secondary pressure and temperature. This degradation in the secondary heat sink creates a mismatch between power generated in the Reactor Coolant System (RCS) and heat removed by the secondary. As a result, the RCS temperature and pressure increase. The expected plant response to a turbine trip would be an immediate reactor trip initiated by the turbine trip signal. The Turbine Bypass System (TBS) and main steam code safety valves would then relieve steam in order to control the post-trip steam generator pressures. RCS pressure would be controlled by the pressurizer spray, PORV, and heaters. In addition, feedwater would be automatically controlled by the Integrated Control System (ICS) to maintain the post-trip steam generator levels at setpoint.

The turbine trip accident is analyzed from a full power initial condition at beginning-of-cycle. The analysis assumes that the pressurizer spray, pressurizer PORV, and the TBS are inoperable. In addition, the pressurizer and main steam code safety valves are modeled using conservative assumptions for drift, blowdown and valve capacity that minimize relief flow. The anticipatory reactor trip on turbine trip is not credited. Main feedwater is isolated coincident with the turbine trip in order to maximize the steam generator pressure. Also, no credit is taken for the Emergency Feedwater System (EFW), since the peak pressure will be reached before EFW flow can start and have an effect on the transient response. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards System setpoints and delay times are given in Table 15-35.

No single failure has been identified which adversely impacts the results of the turbine trip analysis.

The turbine trip accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the 1.50 design limit, and that the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. The DNBR limit is not challenged since the increase in RCS pressure more than offsets the slight increase in RCS temperature.

15.8.2 ANALYSIS

The turbine trip accident analysis results are shown in Figure 15-145, Figure 15-146, Figure 15-147, Figure 15-148, and Figure 15-149, and the sequence of events is given in Table 15-46. The analysis duration of 50 seconds is sufficient to demonstrate the peak RCS pressure. The closure of the main turbine stop valves results in a rapid increase in steam line pressure (Figure 15-145) and temperature. The RCS hot and cold leg temperatures (Figure 15-146) increase due to the increasing secondary side temperature. The increase in RCS temperatures causes pressurizer level (Figure 15-147) and RCS pressure (Figure 15-148) to increase, resulting in a reactor trip on high RCS pressure at 4.0 seconds. Following the reactor trip the RCS temperatures, pressurizer level, and RCS pressure all decrease towards the post-trip values. The reactor power response (Figure 15-149) shows a slight increase due to reactivity feedback prior to trip. At 7.5 seconds, RCS pressure at the bottom of the reactor vessel reaches a maximum value of 2614.1 psig.

9 ## 15.8.3 CONCLUSIONS

9 The turbine trip accident analysis results in a peak RCS pressure of 2614.1 psig. All of the acceptance
9 criteria are met.

15.9 STEAM GENERATOR TUBE RUPTURE ACCIDENT

9 15.9.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

9 The steam generator tube rupture (SGTR) accident is caused by a double-ended rupture of a single steam
9 generator tube. The expected plant response is as follows. The tube rupture initiates a blowdown of
9 primary coolant into a steam generator. The plant response to this event is similar to a small break
9 LOCA in that the Reactor Coolant System (RCS) pressure and pressurizer level would decrease as
9 coolant inventory is lost through the ruptured steam generator tube. Makeup flow to the RCS would
9 increase in response to the decrease in pressurizer level. The Integrated Control System (ICS) would
9 reduce main feedwater (MFW) to the ruptured steam generator to compensate for the break flow.
9 Without operator action, the reactor would trip on the variable low pressure-temperature trip function.
9 With operator action, actions would be taken to initiate a rapid shutdown of the reactor. This would be
9 accomplished by making up for the loss of RCS inventory through the break with flow from the High
9 Pressure Injection System (HPIS). When the reactor power level has been reduced to below the capacity
9 of the Turbine Bypass System (TBS), a manual reactor trip would be performed. Following the reactor
9 trip, the TBS would relieve steam to control steam generator pressure. MFW would be automatically
9 controlled by the ICS to maintain the post-trip steam generator level at setpoint. The operator would
9 then isolate the ruptured steam generator and depressurize the RCS to decrease the subcooled margin,
9 thereby minimizing primary-to- secondary leakage. A plant cooldown and depressurization would then be
9 initiated using the TBS and the unaffected steam generator to bring the plant to the conditions where the
9 Low Pressure Injection System (LPIS) can be aligned for decay heat removal, and break flow could then
9 be terminated. The ruptured steam generator would be steamed and/or drained as necessary to prevent
9 overfill during the course of the event.

9 The SGTR accident is analyzed from a full power initial condition at end-of-cycle with maximum decay
9 heat. Analysis assumptions are selected to maximize the environmental consequences. Offsite power
9 remains available. A conservatively long delay time is assumed for the Reactor Protective System to trip
9 the reactor to maximize the pre-trip primary coolant leakage into the ruptured steam generator. It is
9 further assumed that the operator takes action to maintain RCS pressure and pressurizer level at the initial
9 conditions such that the primary-to-secondary leakage is maximized. The reactor is then assumed to trip
9 from a full power condition which results in the largest post-trip steam release through the main steam
9 safety valves (MSSVs). The MFW pumps are assumed to trip on reactor trip to minimize the secondary
9 heat sink, which actuates the emergency feedwater (EFW) pumps. The non-safety turbine-driven EFW
9 pump is credited in the analysis since the steam supply to its turbine originates from the SG with the tube
9 rupture and exhausts directly to the atmosphere. The non-safety TBS is not credited in the analysis. The
9 analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial
9 conditions are given in Table 15-34. The RPS and Engineered Safeguards Protective System setpoints
9 and delay times are given in Table 15-35.

9 The analysis credits the non-safety manual steam line atmospheric dump valves (ADVs) to cool down the
9 plant. The single failure assumed in this event is the EFW control valve on the unaffected steam
9 generator failing to open following the reactor trip. This results in only the ruptured steam generator
9 being available for cooling down the plant until operator action is taken to establish an alternate EFW
9 alignment. The following operator actions are credited during this event:

9 • Immediate action to maximize HPI flow.
9 • Identify the failed-closed position of the EFW control valve and restore EFW to the unaffected steam
9 generator. A delay time of 23 minutes after reactor trip is assumed.

- The ruptured steam generator is identified 10 minutes after EFW restoration to the unaffected steam generator.
- Cooldown of the plant to 532°F begins 40 minutes after the ruptured steam generator is identified.
- The ruptured steam generator is isolated 10 minutes after the plant has been cooled down to 532°F.
- The RCS subcooled margin is minimized 12 minutes after the ruptured steam generator is identified.
- One reactor coolant pump (RCP) per loop is tripped off 10 minutes after the RCS has been cooled down to 532°F.
- A shift changeover delay of one hour is assumed after the RCS has been cooled down to 532°F and one RCP per loop has been tripped.
- An RCS cooldown to 450°F begins after the shift changeover is complete.
- Cooldown of the RCS is stopped upon reaching 450°F while the RCS boron concentration is determined. A delay time of 90 minutes is assumed.
- Boration of the RCS is performed to achieve the cold shutdown boron concentration requirement. A delay time of 30 minutes is assumed.
- Cooldown to decay heat removal conditions resumes 5 minutes after the cold shutdown boron concentration has been achieved.
- Periodic steaming of the ruptured steam generator is performed to prevent water from entering the steam lines.
- A 45 minute delay is assumed to align the LPIS for decay heat removal. RCS temperature and pressure are held constant during this time.

The steam generator tube rupture accident is considered to be a limiting fault event. The acceptance criterion for this event is that the calculated doses at the site boundary are less than 100% of the 10CFR100 guidelines.

15.9.2 ANALYSIS

The SGTR accident analysis results are shown in Figure 15-150, Figure 15-151, Figure 15-152, Figure 15-153, Figure 15-154, Figure 15-155, and Figure 15-156, and the sequence of events is given in Table 15-47. The duration of the analysis is until the plant has been cooled down and steam releases to the atmosphere have terminated, which is 48,367 seconds (13.5 hours). As a result of the tube rupture and immediate operator action to increase HPIS flow to compensate for the loss of RCS inventory, RCS conditions remain relatively stable until the RPS is assumed to trip the reactor at 1200 seconds. The reactor power response is shown in Figure 15-150. MFW flow is automatically throttled to compensate for the break flow (Figure 15-151) entering the ruptured steam generator. A normal post-trip response occurs, with RCS pressure (Figure 15-152) and pressurizer level (Figure 15-153) decreasing due to RCS shrinkage and steam generator pressures (Figure 15-154) increasing to the MSSV lift setpoints. MFW flow is lost on reactor trip. Steam generator levels (Figure 15-155) decrease to the post-trip setpoints, and then the unaffected steam generator continues to boil down to a dried out condition due to the failure of its EFW control valve to open. Post-trip heat removal is provided by the ruptured steam generator until an alternate EFW flowpath to the unaffected steam generator is aligned at 2580 seconds. After restoration of EFW to both steam generators, the ruptured steam generator is identified at 3180 seconds due to the EFW flow imbalance between the steam generators. The RCS subcooled margin is reduced at 3900 seconds to minimize primary-to-secondary leakage. At 5580 seconds, the unit is cooled down to 532°F (Figure 15-156) using the ADVs on both steam lines. The ruptured steam generator is isolated after reaching 532°F (~6689 seconds), with all steam release flowpaths and EFW being isolated by 7289 seconds. After one RCP is tripped per loop, the RCS is held at a constant temperature and pressure while a shift changeover occurs. During the shift changeover, steaming of the ruptured steam generator begins due to the water level reaching the high level setpoint (11,112 seconds). Steaming the ruptured steam generator continues for the remainder of the analysis. The plant cooldown is resumed following the shift changeover, with RCS temperatures reaching 450°F at 17,080 seconds. Boron sampling and boration to cold shutdown conditions is accomplished by 24,280 seconds, with the plant cooldown

resuming at 24,580 seconds. LPIS decay heat removal conditions are reached at 41,123 seconds, where RCS pressure and temperature are held constant while this system is aligned. The plant cooldown continues at 43,823 seconds, with the RCS reaching 212°F at 48,367 seconds. The analysis is terminated at this time since steam releases to the atmosphere have stopped.

15.9.3 ENVIRONMENTAL CONSEQUENCES

The postulated accidents involving release of steam from the secondary system do not result in a significant release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators as with the SGTR. A conservative analysis of the potential offsite doses resulting from a SGTR accident is presented assuming a pre-existing primary to secondary leakage. This analysis incorporates assumptions of 1 percent ruptured fuel and steam generator leakage prior to the postulated accident for a time sufficient to establish equilibrium specific activities in the secondary system. Two postulated cases are analyzed:

Case 1: Equilibrium RCS iodine concentrations consistent with 1%-failed fuel exist at the time of the accident. No iodine release rate spiking is assumed.

Case 2: Pre-existing iodine spike at the time the accident occurs. The reactor coolant concentrations are the maximum permitted for full power operation (50 times the normal equilibrium Technical Specification limit).

The secondary side coolant activity prior to the accident corresponds to limits set by Technical Specifications.

The initial conditions, boundary conditions and assumptions of the analysis were chosen to maximize the release of radionuclides to the environment by maximizing the stored energy in the primary system, the primary to secondary leakage, and the secondary-side pressurization. The following are used to calculate the activity release and offsite dose for SGTR accident:

1. The reactor is assumed to be at the end of a 500 EFPD cycle with extended operation at 102% full power (2619.4 MWt).
2. Prior to the accident, an equilibrium activity of fission products exists in the primary system.
3. The accident is initiated by the rupture of a steam generator tube, which results in a time-varying leakage rate of reactor coolant into the shell side of the ruptured steam generator.
4. No core fuel cladding ruptures or fuel melting occur during the accident.
5. Offsite power is maintained for the duration of the accident.
6. A pre-existing 1 gpm primary to secondary leakage is assumed to be located in the unaffected steam generator. The leakage rate varies as the plant is cooled to cold shutdown (Mode 5).
7. The steam release from the ruptured steam generator terminates at 13.5 hours, once the RCS has been cooled to cold shutdown (Mode 5) conditions and the RCS pressure is less than or equal to the pressure in the secondary-side of the faulted OTSG. The release from the nonruptured steam generator terminates at the same time.
8. The concentrations of noble gases in the secondary side water are assumed to be negligible since any noble gases entering the secondary side are continuously vented to the atmosphere.
9. The following iodine partition coefficients are assumed:

    1) The steam generator steam/water interface iodine partition coefficient is 1.

9 9 2) The partition coefficient for main steam/auxiliary steam providing the motive force in the condenser steam air ejectors (CSAEs) is 1.

9 9 3) The condenser partition coefficient is 10,000 for iodine entering the condenser and then exiting via the CSAEs to the unit vent.

9 9 10. Credit is taken for the effect of radioactive decay of the RCS and secondary side radionuclide inventories during the progression of the accident.

9 9 11. For Case 1, the primary coolant concentration is at the equilibrium levels consistent for 1% failed fuel, which bounds the equilibrium Technical Specification limit.

9 9 12. For Case 2, the primary coolant concentration is at the maximum permitted for full power operation (50 times the normal equilibrium Technical Specification limit).

9 9 13. For both cases, the initial concentration of SG inventory and the feedwater are assumed to be based on 0.1 μCi/g DEI-131, the maximum concentration permitted by Technical Specification

9 14. Other parameters are listed in Table 15-52.

9 9 9 9 Based on the foregoing model, the thyroid and whole body doses are calculated at the exclusion area boundary and the low population zone. The results are presented in Table 15-52. The doses at these distances are below the regulatory acceptance criteria of full 10 CFR 100 limits, for each of the above cases analyzed.

9 15.9.4 CONCLUSIONS

9 9 9 The steam generator tube rupture accident is analyzed to provide conservative inputs to the environmental consequences analysis. The results of the environmental consequences analyses are within the 10CFR100 limits. All of the acceptance criteria are met.

15.9.5 REFERENCES

9 1. Deleted per 1999 Update

9 2. Deleted per 1999 Update

9 3. Deleted per 1999 Update

6 4. Deleted per 1996 Update

15.10 WASTE GAS TANK RUPTURE ACCIDENT

15.10.1 IDENTIFICATION OF ACCIDENT

9 Rupture of a waste gas tank would result in the release of the radioactive contents of the tank to the plant
9 auxiliary building ventilation system and to the atmosphere through the unit vent. The release is assumed
9 to occur over a two hour period to maximize the exclusion area boundary dose. Dose to a receptor at the
9 site boundary and the control room dose evaluated.

15.10.2 ANALYSIS AND RESULTS

9 A tank is assumed to contain the maximum inventory expected based on a technical specification limit
9 which requires that offsite dose from a tank rupture be limited to 500 millirem. The tank inventory
9 assumed in this analysis is far greater than the expected operational inventory and is not based on actual
9 operation of the system. The shared unit 1 & 2 tank is considered as the limiting case and is assumed to
9 contain the following noble gas inventory.

	Waste Gas Tank Inventory
Isotope	Activity (Ci)
Kr-85m	888
Kr-85	68,657
Kr-87	484
Kr-88	1,519
Xe-133m	2,560
Xe-133	186,345
Xe-135m	282
Xe-135	5,344

9 The Total Effective Dose Equilivant from a puff release of this inventory to the site boundary is calculated
9 to be 0.44 Rem at the exclusionary boundary and 0.048 Rem at the Low Population Zone boundary.
9 Control Room Dose is calculated to be 0.338 Rem TEDE.

15.11 FUEL HANDLING ACCIDENTS

15.11.1 IDENTIFICATION OF ACCIDENT

Spent fuel assemblies are handled entirely under water. Before refueling, the reactor coolant and the fuel transfer canal water above the reactor are increased in boron concentration so that, with all control rods removed, the k_{eff} of a core is no greater than 0.99. In the spent fuel storage pool, the fuel assemblies are
7 stored under water in storage racks with a minimum boron concentration as specified by the Core
7 Operating Limits Report (COLR) in the pool water. Under these conditions, a criticality accident during refueling is not considered credible. Fuel handling consists of all fuel assembly shuffling and transfer
3 operations between the reactor, the spent fuel pool, the fuel shipping casks, and dry storage transfer cask. Mechanical damage to the fuel assemblies during transfer operations is possible but improbable. The mechanical damage type of accident is considered the maximum potential source of activity release during refueling operations.

15.11.2 ANALYSIS AND RESULTS

5 **15.11.2.1 Base Case Fuel Handling Accident in Spent Fuel Pool**

5 During fuel handling operations, it is possible that a fuel assembly can be dropped, causing mechanical
5 damage with a subsequent release of fission products. To conservatively evaluate the offsite dose
5 consequences of such an accident, conservative assumptions are made. The following analysis assumes
5 the accident occurs within the spent fuel pool building.

5 The fuel assembly gap inventory is assumed to contain a fission product inventory from a maximum
5 burned fuel assembly at a radial peaking factor of 1.65. The gap fractions used are from Reg. Guide 1.25
5 and the reactor has been shutdown for 72 hours, which is the minimum time for RCS cooldown, reactor
5 closure head removal, and removal of the first fuel assembly. The actual isotopic curie contents are listed
5 in Table 15-1. It is also assumed that all 208 fuel pins are mechanically damaged such that the entire gap
5 inventory is released to the surrounding water. Since the fuel pellets are cold, only the gap inventory is
5 released.

5 The gases released from the damaged fuel assembly pass upward through the spent fuel pool water prior
5 to reaching the Auxiliary Building atmosphere. Noble gases are assumed to not be retained in the pool
5 water. According to Reg Guide 1.25, an iodine decontamination factor of 100 can be used for pin
5 pressures less than, or equal to, 1200 psig and water depths of 23 feet or greater. Since the spent fuel pool
5 racks are at an elevation of 816.5 feet and the minimum water level in the Spent Fuel Pool is equal to or
5 greater than 837.84 feet (-2.0 ft indicated level), there is a minimum of 21.34 feet of water over the fuel
5 storage racks, including instrument error. An experimental test program (Reference WCAP-7828)
5 evaluated the extent of removal of iodine released from a damaged irradiated fuel assembly. Iodine
5 removal from the released gas takes place as the gas rises through the water. The extent of iodine removal
5 is determined by mass transfer from the gas phase to the surrounding liquid and is controlled by the
5 bubble diameter and contact time of the bubble with the water. The following analytical expression is
5 given as a result of this experimental test program:

5 $$\text{Iodine Decontamination Factor (DF)} = 73\ e^{0.313\,(t/d)}$$

5

Where: t = bubble rise time, seconds
d = effective bubble diameter, cm

Since the minimum water depth over a dropped fuel assembly is less than 23 feet (21.34 feet), the assumed iodine DF must be less than 100, according to Reg. Guide 1.25, and calculated with comparable conservatism as done in Reg. Guide 1.25. Using the above relationship, with a water depth of 21.34 feet, a comparable DF is equal to 89 (Reference OSC-6070).

Duke will use a DF equal to 89 for a maximum rod internal pressure in the spent fuel pool of 1300 psig for the handling accident analysis per Reference 21. This was justified in Reference 21 using the WCAP-7828 methodology described above and approved by the USNRC per Reference 22.

The fuel rod internal pressure, at a Spent Fuel Pool bulk temperature of 150 F, would remain less than 1200 psig, (based on the present TACO2 computer code (Reference 23) licensing limit of 2200 psia at operating system conditions) or is calculated to be less than 1300 psig (based on the present TACO3 computer code (Reference 24) licensing limit of a proprietary value above nominal system pressure at operating system conditions) (Reference FSAR Section 4.2.3.1.3, "Fuel Thermal Analysis").

The activity released from the water's surface is released within a two-hour period as a ground release. The atmospheric dilution is calculated using the two-hour ground release dispersion factor of 2.2×10^{-4} sec/m^3.

The total integrated dose (2-hr EAB) to the whole body at the 1-mile exclusion distance is 0.185 Rem and the thyroid dose at the same distance is 52.45 Rem. These values are far below the limits given in 10CFR100 of 25 Rem whole body and 300 Rem thyroid.

15.11.2.2 Base Case Fuel Handling Accident Inside Containment

In 1977, the NRC asked Oconee to evaluate the offsite dose consequences for a fuel handling accident inside containment, per the guidance given in Reg. Guide 1.25. Since the shallow end of the fuel transfer canal is at an elevation of 816.5 feet, the same iodine decontamination factor used for the Fuel Handling Accident in the Spent Fuel Pool is used for the Fuel Handling Accident inside Containment. The activity released from the refueling water is released as a ground release, which has an atmospheric dispersion factor of 2.2×10^{-4} sec/m^3. There is no credit taken for any containment closure/integrity resulting in the released activity from the refueling water going straight outside.

Using the fuel assembly gap inventory in Table 15-1, and assuming all 208 fuel pins are damaged, the two-hour EAB dose is 0.185 Rem to the whole body and 52.45 Rem to the thyroid. These values are appropriately within the guidelines given in 10CFR100 (appropriately within means 100 Rem to the thyroid), and are identical to the base case Spent Fuel Pool Fuel Handling Accident described in Section 15.11.2.1, "Base Case Fuel Handling Accident in Spent Fuel Pool."

15.11.2.3 Supplemental Cases of Fuel Handling Accidents

To provide additional information as to the sensitivity of various input assumptions into the offsite dose consequences of the fuel handling accident, additional supplemental cases are described here.

<u>CASE A:</u>

If the radioisotope release from the spent fuel pool water's surface is assumed to be captured by the Spent Fuel Pool Ventilation System, resulting in an elevated release, (atmospheric dispersion factor is equal to

5 3.35 x 10^{-5} sec/m^3) and assuming that the Spent Fuel Pool Filters are 90% efficient for the removal of
5 elemental and particulate iodine, and 70% efficient in the removal of organic iodine, the resultant
5 two-hour offsite dose is calculated to be 1.2 Rem thyroid and 0.021 Rem whole body at the exclusion
5 area boundary (EAB).

5 CASE B:

5 If it is assumed that the spent fuel pool water only retains 90 of the iodine released from the damaged fuel
5 assembly (DF = 10), and that the Spent Fuel Pool Ventilation System captures the radioisotope release
5 from the water surface (elevated release: X/Q = 3.35 x 10^{-5} sec/m^3; but assuming no iodine filtration), the
5 calculated two-hour EAB doses are 71.1 Rem thyroid and 0.1 Rem whole body.

5 CASE C:

5 If it assumed that a fuel assembly is damaged by the Cask Platform in the Spent Fuel Pool (el. 825 ft.)
5 such that the iodine decontamination factor is only 46.2, the two-hour EAB doses for a ground release
5 (X/Q = 2.2 x 10^{-4} sec/m^3), are calculated to be 101.1 Rem thyroid and 0.24 Rem whole body.

5 **15.11.2.4 Fuel Shipping Cask Drop Accidents**

Fuel shipping casks are used to transport irradiated fuel assemblies from the site and also between the Oconee 1 and 2 spent fuel pool and the Oconee 3 spent fuel pool. Two hypothetical accident scenarios, the maximum free fall drop of a cask containing an irradiated assembly, and a cask drop onto the irradiated assemblies in the storage racks in the spent fuel pools are considered (References 5, 6, 7).

The analysis of the maximum free fall drop of a cask containing an irradiated fuel assembly is made based on the worst position of the cask suspended by the crane above the cask handling area. A drop of 46 ft. is assumed to rupture the cask and release the activity from the contained fuel assembly. The assembly is assumed to have the maximum inventory from the core corresponding to a radial peaking factor of 1.65 and has undergone a 90 day decay period. The dose consequences were calculated in accordance with
5 Regulatory Guide 1.25. The results are a whole body dose of 5.2 x 10^{-4} rem and 2.5 rem thyroid at the
5 site boundary, within the 10CFR100 limit.

The worst case fuel handling accident sequence in which the fuel shipping cask impacts on the irradiated fuel assemblies in a spent fuel pool is evaluated. At no time is the cask suspended above the spent fuel pool; however, it is credible that with failure of the cask hoist cable that the cask, yoke, hook, and load block could, as a result of an eccentric drop, deflect and fall into the spent fuel pool and impact on top of the assemblies in the pool. The analysis is performed separately for the shared Unit 1 and 2 spent fuel pool and the Unit 3 spent fuel pool. In the first part of the analysis, the number of fuel assemblies damaged as a result of the cask drop is found. Subsequently the radiological consequences of the damaged assemblies are determined.

The following conservative assumptions are employed for determining the number of fuel assemblies damaged.

1. The cask, lifting yoke and load block are free to fall from elevation 844 ft., the top of the spent fuel pool, to elevation 816 ft. 5 in., the top of the fuel storage racks.
2. The drag on the cask, lifting yoke and load block from falling through 25.5 ft. of water is neglected.
3. The ability of the fuel storage cells to absorb energy beyond the point of elastic buckling is neglected.
4. The energy which is expended in deformation of the rack interconnecting members is neglected.
5. A deformed fuel storage cell results in the total loss of integrity of one fuel assembly.

6. The projected areas of the cask, lifting yoke and load block are oriented to contact the maximum number of fuel assemblies.

Using the above assumptions, the falling cask, lifting yoke, and load block will have 2.093 x 10^6 ft-lbf of kinetic energy at the instant of impact with the storage racks. This energy must be absorbed by the strain energy in the storage racks. For additional conservatism it is assumed that the storage racks which are directly impacted by the falling load in turn buckle and deflect into adjacent racks until the total energy of the falling cask is absorbed. The Unit 1 and 2 spent fuel pool contains 154 fuel storage positions under the direct impact area, with a total of 576 spent fuel assemblies which can potentially suffer a loss of integrity during a cask drop accident. The Unit 3 pool contains 156 fuel storage positions under the projected impact area, with a total of 518 assemblies which can be damaged during the accident. These analyses are based on the TN-8 three element shipping cask.

Once the number of fuel assemblies which could be damaged is determined, dose analyses are performed which are consistent with Regulatory Guide 1.25, and NUREG-0612. The following assumptions apply:

1. Spent fuel stored in the first 36 rows of the Unit 1 and 2 spent fuel pool closest to the spent fuel cask handling area has decayed at least 55 days. This is consistent with Technical Specification 3.7.15.a, "Plant Systems".
2. All fuel assemblies assumed damaged in excess of two full cores (354 assemblies) in the Unit 1 and 2 spent fuel pool are assumed to have decayed at least one year.
3. Spent fuel stored in the first 33 rows of the Unit 3 spent fuel pool closest to the spent fuel cask handling area has decayed at least 70 days. This is consistent with Technical Specification 3.7.15.b., "Plant Systems".
4. All fuel assemblies assumed damaged in excess of one full core (177 assemblies) in the Unit 3 spent fuel pool are assumed to have decayed at least one year.
5. The affected assemblies have the maximum core activity corresponding to a radial peaking factor of 1.2.
6. All rods of the affected assemblies are ruptured.
7. The iodine decontamination factor in pool water is 89.
8. There is no removal of activity by the spent fuel pool ventilation system filters prior to release to the environs.
9. Activity is released at ground level with an assumed χ/Q factor of 2.2 x 10^{-4} sec/m^3.
10. The fractions of noble gases and iodine in the gaps are

Kr-85, I-129	30%
All other noble gases	10%
All other iodines	10%

The results of the cask drop analyses are as follows:

	Dose at Exclusion Area Boundary (Rem)	
	Whole Body	Thyroid
Unit 1 and 2 Cask Drop	0.13	142

Unit 3 Cask Drop	0.07	20

The offsite radiological consequences of the postulated cask drop accident in the Unit 1 and 2 spent fuel pool is within the 10 CFR100 limits. The offsite radiological consequences of the postulated cask drop accident in the Unit 3 spent fuel pool is well within 10CFR100 limits.

15.11.2.5 Dry Storage Transfer Cask Drop Accident in Spent Fuel Pool Building

Dry storage transfer operations from the spent fuel pool (SFP) buildings to the Independent Spent Fuel Storage Facility (ISFSI) are routinely performed at Oconee. The major steps in the process involve transporting the transfer cask/dry storage canister (DSC) into the fuel building, placing into the SFP, loading with 24 qualified fuel assemblies, drying/sealing, and removing to the ISFSI. The potential exists for dropping the cask in the SFP area during transfer operations.

15.11.2.5.1 Criticality Analyses for Dry Storage Transfer Cask Drop Scenarios

While the transfer cask is never carried directly over spent fuel, the potential always exists for failure of the overhead crane or handling equipment. Thus, an analysis was performed assuming the cask, yoke, and yoke block are deflected into the Unit 1&2 SFP. In such a case, it was postulated that 1024 spent fuel assemblies (SFAs) would be damaged (the first 64 rows, each containing 16 SFAs). It was assumed that 220 fuel storage cells directly beneath the falling parts buckle and deflect into adjacent cells until all the energy of the dropping cask is absorbed. For a cask drop in the smaller Unit 3 SFP, it was assumed all 825 fuel cell locations would be damaged.

The potential for criticality in the SFPs was analyzed using the methodology identified in NUREG-0612. It was assumed the racks and fuel were deformed such that k_{eff} was maximized. Credit was taken for pool boron, boraflex, and stainless steel walls to determine the k_{eff} under the assumed damage conditions. The confirmatory calculations utilized a specific neutronic analysis for each SFP with the following assumptions:

1. An infinite array of SFAs is crushed together into a geometry that optimizes k_{eff}.
2. The affected SFAs are unirradiated and have the maximum enrichment permitted for storage in the Oconee SFPs.
3. The minimum technical specification for SFP boron concentration is maintained.

This is a Plant Condition IV event as defined in ANSI/ANS-57.2-1983. The acceptance criteria for this accident, from Reference 10, is that k_{eff} will be less than or equal to 0.98 including all uncertainties. A series of calculations involving cases of varied pin pitch modeling the crushed cells and SFAs was performed. The maximum k_{eff} value determined for the Unit 1&2 SFP was 0.97206. The maximum k_{eff} value calculated for the Unit 3 SFP was 0.94169. These analyses verify that subcriticality in the SFP will be maintained after a dry storage cask drop accident.

The DSC internals are designed to prevent criticality during the wet loading and unloading process. As long as the SFP boron concentration is within the limit specified in the Core Operating Limits Report, and for DSCs loaded under the Site Specific License SNM-2503, the DSC is drained of water within 50 hours of loading the SFAs, criticality is precluded. Strict administrative controls are in place at Oconee to ensure the SFP boron concentration is maintained above the minimum required and that the draining time for Site Specific DSC's limit is not exceeded. Once the moderator (water) is removed, there is no criticality concern during normal transportation of the DSC. However, the potential exists for the fully loaded cask to fall a distance of 40-50 feet onto the transfer trailer and rupture, with damage possible to

the DSC. Even so, it is not possible for the 24 fuel assemblies contained in the DSC to be forced into a critical configuration while surrounded by air or helium gas.

The consequences of dropping the dry storage transfer cask outside the fuel building are described in the ISFSI FSAR (Reference 11, 12).

15.11.2.5.2 Potential Damage to SFP Structures from Dry Storage Transfer Cask Drop

The SFP is founded on rock, and the concrete floor slab is designed to withstand the 100 ton cask drop. However, localized concrete could be crushed and the steel liner plate punctured in the area of dry storage cask impact. For the purpose of analyzing the event, a gap of 1/64 inch for a perimeter of 308 inches in the liner plate was assumed. The calculated leakage of pool water through the gap is 21.3 gallons per day. This amount of water loss is within the capability of the SFP makeup sources. The cask is never carried over any safety related equipment.

15.11.2.5.3 Radiological Dose from Dry Storage Transfer Cask Drop

The worst radiological consequences resulting from a dry storage cask drop accident into either the Unit 1&2 or the Unit 3 SFP were analyzed. The calculation assumes a total of 1024 SFAs would be damaged in the Unit 1&2 SFP. Of this number, two full core inventories (354 SFAs) with worst case fission product concentration and less than 1 year decay time are assumed to be present. For the Unit 3 SFP, all 825 fuel cell locations are assumed to contain SFAs that would be damaged by the cask drop. One full core inventory (177 SFAs) with worst case fission product inventory and less than 1 year decay is considered to be present in the Unit 3 pool. Thus, the analysis assumes 670 and 648 SFAs, for Unit 1&2 and Unit 3 SFPs respectively, have a minimum of 1 year decay time.

Oconee Technical Specification 3.7.15.c, "Plant Systems," requires that fuel stored in the first 64 rows closest to the cask handling area be decayed a minimum of 65 days prior to movement of the dry storage transfer cask in the Unit 1&2 SFP area. Likewise, Technical Specification 3.7.15.d, "Plant Systems," requires all SFAs stored in the Unit 3 pool must be decayed a minimum of 57 days before movement of the cask is permitted in that area. The maximum fission product inventories for the iodine and noble gas nuclides of interest at times of 57 days, 65 days, and 1 year were calculated using the N237 BURP computer program. This information, in conjunction with the assumed pool inventories, was used to determine the curies of each nuclide released from the postulated cask drop accidents. The total activity releases for each pool were used to determine the worst case offsite dose consequences reported below:

FUEL POOL	NUMBER OF SFAs DAMAGED	TOTAL BODY DOSE (REM)	THYROID DOSE (REM)
Units 1&2	1024	0.14	60
Unit 3	825	0.12	60

The above doses, taken separately, are less than 25% of the 10 CFR Part 100 limits of 25 rem to the whole body and 300 rem to the thyroid. Therefore, the accident dose criteria will not be exceeded for the limiting postulated dry storage cask drop accident.

15.11.3 REFERENCES

5 5 1. DPC Engineering Calculation OSC-6070, "Offsite Dose Consequences From Fuel Handling Accidents", dated March 21, 1996.

5 2. WCAP-7828, "Radiological Consequences of a Fuel Handling Accident", December 1971.

5 5 3. DPC Engineering Calculation OSC-6089, "Oconee Fission Product Source Terms", dated March 21, 1996.

5 4. Parker, W. O. Jr., Letter to Rusche, B. C. (NRC), March 10, 1977.

5 5. Parker, W. O. Jr., Letter to Rusche, B. C. (NRC), November 3, 1975.

5 6. Parker, W. O. Jr. (Duke), Letter to Denton, H. R. (NRC), July 25, 1980.

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5 5 8. DPC Engineering Calculation OSC-2840, "Cask Drop Accidents - Radiological Consequences - ISFSI Cask", dated Feb 26, 1988.

5 5 9. DPC Engineering Calculation OSC-3631 Rev 2, "Criticality Consequences of a Heavy Load Drop in the Spent Fuel Pool", dated February 7, 1996.

5 5 10. Weins, L. A. (NRC), Letter (with attached Safety Evaluation) to Tucker, H. B. (DPC) dated November 16, 1989.

7 5 11. Oconee Nuclear Station Site Specific Independent Spent Fuel Storage Installation, Final Safety Analysis Report, Chapter 8.

8 8 12. Oconee Nuclear Station Independent Spent Fuel Storage Installation General License, Updated Final Safety Analysis Report.

15.12 ROD EJECTION ACCIDENT

9 15.12.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

9 The rod ejection accident is caused by a failure of a control rod drive mechanism housing, which allows a
9 control rod to be rapidly ejected from the reactor by the Reactor Coolant System (RCS) pressure. The
9 control rod is ejected in 0.15 seconds from the fully inserted position. A power excursion will result, and
9 if the reactivity worth of the ejected control rod is large enough, the reactor will become prompt critical.
9 The resulting power excursion will be limited by the fuel temperature feedback and the accident will be
9 terminated when the Reactor Protective System (RPS) trips the reactor on high neutron flux or high RCS
9 pressure. RCS pressure increases due to the core power excursion, and pressurizer spray, the pressurizer
9 PORV, and the pressurizer code safety valves will respond to mitigate the pressure increase. If a rod
9 ejection were to occur, the nuclear design of the reactor and limits on control rod insertion will limit any
9 potential fuel damage to acceptable levels. Cladding failure can result from the core power excursion and
9 the highly peaked core power distribution near the ejected rod location. The failure of the control rod
9 drive mechanism housing also constitutes a 1.50 inch diameter small-break LOCA (SBLOCA). The
9 Emergency Core Cooling System (ECCS) will actuate on low RCS pressure or high Reactor Building
9 pressure and will maintain core cooling. This type of SBLOCA is bounded by the limiting SBLOCA
9 analyses presented in Sections 6.2, "Containment Systems" and 15.14, "Loss of Coolant Accidents."

9 Six rod ejection accident cases with different initial core conditions and number of reactor coolant pumps
9 (RCPs) in operation are analyzed. Two cases initiate at zero power (1E-7% of full power) with two
9 RCPs in operation, at both beginning-of-cycle (BOC) and at end-of-cycle (EOC). Two cases initiate at
9 82% power with three RCPs in operation, at both BOC and EOC. Two cases initiate at 102% power
9 with four RCPs in operation, at both BOC and EOC. Since cladding failure due to exceeding the DNBR
9 limit will result, the different possible RCP operating conditions are analyzed to bound the effect of core
9 flowrate on DNBR. Zero power and full power are both analyzed to bound the range of ejected rod
9 worths, initial fuel temperatures, and core power distributions. The ejected rod worth for each case is
9 based on the power level dependent rod insertion limit including uncertainty. The negative reactivity
9 inserted on reactor trip assumes that the most reactive control rod remains in the fully withdrawn
9 position. The pressurizer spray and PORV are not credited for mitigating the pressure transient in the
9 evaluation of the peak RCS pressure response. The analysis methodology and the computer codes used
9 in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The RPS and
9 Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

9 Due to the asymmetric core power distribution resulting from the rod ejection, the excore power range
9 flux channels which input to the RPS high flux trip function will indicate different transient power
9 responses. The analyses assume a single failure of the excore flux channel which indicates the highest
9 power level. This assumption results in the third highest excore flux channel determining the time of
9 reactor trip based on the 2/4 RPS trip logic design.

9 The rod ejection accident is considered to be a limiting fault. The acceptance criteria for the rod ejection
9 accident analysis are that the accident will not further damage the RCS, and that the offsite doses will be
9 less than 100% of the 10CFR100 limits. The first criterion of no further damage to the RCS is
9 interpreted to mean that the peak RCS pressure and the peak pellet radial average enthalpy both remain
9 below a specified limit. The peak primary pressure limit is to remain within Service Limit C as defined by
9 the ASME Code (Reference 13), which is 120% of the 2500 psig design pressure, or 3000 psig. The peak
9 enthalpy limit is such that the radially averaged fuel pellet enthalpy shall not exceed 280 cal/gm at any
9 location in the core. To evaluate the second criterion of offsite dose being within the 10CFR100 limits,

9 the extent of fuel failures are quantified with the assumption that any fuel pin that exceeds the DNB limit
9 of 1.24 is considered failed. The fuel failure results are used in the offsite dose calculations to verify that
9 the offsite dose criteria are satisfied. The offsite dose analysis also considers the SBLOCA release to the
9 Reactor Building.

9 15.12.2 CORE KINETICS ANALYSIS

9 The rod ejection accident core kinetics response is determined with a three-dimensional space/time
9 analysis for each of the six cases. The analysis duration of 5 seconds is sufficient to determine the results
9 of interest. The assumed ejected rod worths are 200 pcm at 102% power, 400 pcm at 82% power, and
9 800 pcm at 1E-7% of full power. Only the ejected rod worth at 1E-7% of full power is large enough to
9 cause prompt criticality (reactivity greater than one dollar). The results of the SIMULATE-3K analyses
9 are summarized in Table 15-2. The 102% power cases trip in 0.05 seconds and reach maximum neutron
9 power levels of 140% and 137% at BOC and EOC, respectively. The 82% power cases trip in 0.08
9 seconds, and reach maximum neutron power levels of 194% and 214% at BOC and EOC, respectively.
9 The 1E-7% FP cases trip in 0.25 seconds, and reach maximum neutron power levels of 1841% and
9 1752% at BOC and EOC, respectively. The results of the ARROTTA analyses are summarized in
9 Table 15-3. The 102% power cases trip in 0.05 seconds and reach maximum neutron power levels of
9 144% and 148% at BOC and EOC, respectively. The 82% power cases trip in 0.08 seconds, and reach
9 maximum neutron power levels of 195% and 223% at BOC and EOC, respectively. The 1E-7% FP
9 cases trip in 0.25 seconds, and reach maximum neutron power levels of 2098% and 1918% at BOC and
9 EOC, respectively. The neutron power transients for all six cases and for both computer codes are shown
9 in Figure 15-29, Figure 15-30, Figure 15-31, Figure 15-32, Figure 15-33, and Figure 15-34. In each case
9 the power excursion is terminated by the Doppler temperature feedback, and then the reactor is shut
9 down by the reactor trip on high flux. Figure 15-35 shows the core power distribution at the time of
9 peak power for the ARROTTA 102% power BOC case. This figure illustrates the high assembly peaking
9 factors near the ejected rod location.

9 15.12.3 FUEL PELLET ENTHALPY ANALYSIS

9 For each of the six rod ejection accident cases, the core power excursion and the time-dependent
9 three-dimensional power distribution from the ARROTTA core kinetics analysis is used as input to the
9 calculation of the fuel pellet peak radial average enthalpy. The results for the six cases are shown in
9 Table 15-3. The limiting case is the 102% power case at BOC conditions, with a peak enthalpy of 132.8
9 cal/gm.

9 15.12.4 CORE COOLING CAPABILITY ANALYSIS

9 For each of the six rod ejection accident cases, the core power excursion from the ARROTTA core
9 kinetics analysis is combined with the core flowrate, temperature, and pressure transients from the system
9 analysis to determine the DNBR response. A range of assembly peaking factors and axial shapes are
9 assumed to determine the peaking factors at which the DNBR limit is exceeded for each of the six cases.
9 These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel rod in
9 the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the
9 fuel rod exceeds the DNBR limit. All fuel rods that exceed the DNBR limit are assumed to experience
9 cladding failure and are included in the source term for the offsite dose calculation. Table 15-3 shows the
9 percentage of fuel pins that exceed the DNBR limit for each case. The limiting case is the 102% power
9 case at BOC, with 40.6% of the fuel rods predicted to exceed the DNBR limit.

15.12.5 PEAK RCS PRESSURE ANALYSIS

The peak RCS pressure for the ARROTTA rod ejection accident is determined by a system analysis simulation that uses a boundary condition of the coolant expansion rate in the core. The core coolant expansion rate is calculated for each fuel assembly and is summed into a total expansion rate. The total coolant expansion rate is then input to the system analysis, which results in a pressurizer insurge and a compression of the pressurizer steam bubble. The peak RCS pressure results from the 82% power BOC case. Figure 15-36 shows the pressure transient, which peaks at 2885 psig at 2.3 seconds.

15.12.6 ENVIRONMENTAL CONSEQUENCES

A conservative analysis for a postulated rod ejection accident is performed to determine the resulting radiological consequences. The rod ejection accident offsite dose calculation is based on the approach provided in Regulatory Guide 1.77, with the exception that credit is taken for concurrent releases of primary coolant to the Reactor Building and secondary-side of the steam generators, when estimating doses arising from secondary system releases. During the accident, two activity release paths contribute to the total radiological consequences. The first release path is via containment leakage resulting from release of activity from the primary coolant and failed fuel pins to the Reactor Building. The second path is the contribution of primary-to secondary leakage and contaminated secondary coolant releases to the atmosphere. The consequences arising from these release paths are evaluated separately and then are combined to provide a total accident estimate.

The initial conditions, boundary conditions and assumptions of the analysis were chosen to maximize the release of radionuclides to the environment by maximizing the initial fission product inventories, containment fission product releases, the primary to secondary leakage, and the secondary-side coolant releases. The following are used to calculate the activity releases and offsite dose for the postulated rod ejection accident:

1. The reactor is assumed to be at the end of a 500 EFPD cycle with extended operation at 102% full power (2619.4 MWt).
2. Prior to the accident, an equilibrium RCS activity corresponding to 1 percent failed fuel exists in the primary system.
3. No core fuel melting occurs.
4. The accident is initiated by the ejection of a control rod element, resulting in a breach in the reactor vessel head.
5. Fifty percent (50%) of the fuel rods in the core are analyzed to fail due to DNB, releasing all stored gap activity. Due to the magnitude of the resulting RCS fission product activities, no iodine release rate spiking is assumed.

The following are used in the analysis of the Containment path releases of radioactivity to the environment:

6. The initial concentration of SG inventory and the feedwater are assumed to be equivalent to 0.1 μCi/gm DEI-131.
7. The containment leak rate is 0.25 percent per day for the first 24 hours, and 50 percent of this rate thereafter.
8. The ECCS leakage during the sump recirculation is assumed to be 2 gallons per hour. There is no ECCS leakage during the injection phase.

9. For evaluation of non-ECCS releases from the RB, all (100%) of the noble gases and a quarter (25%) of the RCS coolant and fuel pin gap iodine inventories are assumed to be released to the containment atmosphere.
10. For evaluation of ECCS-related releases from the RB, all (100%) of the RCS coolant and fuel pin gap iodine inventories are assumed to be deposited in the RB sump water.
11. The iodine chemical species fractions are 0.91 elemental, 0.05 particulate, and 0.04 organic.
12. Fifty percent of the Containment leakage bypasses the Penetration Room Ventilation System (PRVS) filters.
13. The PRVS filter removal efficiencies are 90% for elemental iodine, 90% for particulate iodine, and 70% for organic iodine species.
14. No credit is taken for iodine removal from the containment atmosphere by the Reactor Building sprays.
15. Credit is taken for the effect of radioactive decay of the RCS and secondary-side radionuclide inventories during the progression of the accident.
16. To maximize ECCS leakage releases, the switchover to the Reactor Building sump recirculation mode is conservatively assumed to begin 30 minutes into the accident.
17. The assumed volume of water in the sump post- accident is 45,724 cubic feet.
18. The flashing fraction of the ECCS leakage is assumed to be 0.05.

The following are used in the analysis of the secondary system releases of radioactivity to the environment:

19. All (100 percent) of the noble gases and iodine present in the fuel gap regions of the 50% failed fuel is mixed instantaneously within the entire reactor coolant volume, with the pre-existing RCS activity.
20. During the plant cool-down, credit is taken for depletion of the RCS fission product activities by radioactive decay and by releases to containment through the breach in the RCS pressure boundary created by the ejected rod.
21. The initial primary to secondary leak rate is 300 gal/day, distributed equally between the two OTSGs.
22. The following iodine partition coefficients are assumed:
    - **a)** The steam generator steam/water interface iodine partition coefficient is 1.
    - **b)** The partition coefficient for main steam/auxiliary steam providing the motive force in the condenser steam air ejectors (CSAEs) is 1.
    - **c)** The condenser partition coefficient is 10,000 for iodine entering the condenser and then exiting via the CSAEs to the unit vent.
23. All noble gases within the RCS coolant released to the OTSG secondary sides are immediately released to the atmosphere, with no retention in the secondary coolant.
24. Offsite power is maintained for the duration of the accident.
25. Other parameters are listed in Table 15-53.

Based on the foregoing model, the primary and secondary side releases may be calculated, as well as the offsite doses. The doses corresponding to Containment releases, to secondary-side releases, and the composite accident doses are given in Table 15-53. The offsite doses for the postulated rod ejection accident are below the regulatory acceptance criteria of full 10 CFR 100 limits for 0-2 hour exclusion area boundary and the outer boundary of the low population zone.

9 ## 15.12.7 CONCLUSIONS

9 The rod ejection accident is analyzed for six cases which include different initial conditions for power
9 level, number of RCPs in operation, ejected rod worth, and core physics parameters associated with BOC
9 and EOC conditions. The limiting peak fuel pellet average enthalpy is 132.8 cal/gm. The maximum
9 predicted fuel cladding failure percentage is 40.6%. The peak RCS pressure is 2885 psig. The
9 environmental consequences analysis results are within the 10CFR100 limits. All of the acceptance
9 criteria are met.

15.12.8 REFERENCES

9 1. Deleted per 1999 Update

9 2. Deleted per 1999 Update

9 3. Deleted per 1999 Update

9 4. Deleted per 1999 Update

9 5. Deleted per 1999 Update

9 6. Deleted per 1999 Update

9 7. Deleted per 1999 Update

9 8. Deleted per 1999 Update

9 9. Deleted per 1999 Update

9 10. Deleted per 1999 Update

9 11. Deleted per 1999 Update

6 12. Deleted per 1996 Update

9 13. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components", ASME

15.13 STEAM LINE BREAK ACCIDENT

15.13.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

The steam line break accident is caused by a double-ended rupture of one of the two main steam lines. The expected plant response to a large steam line break is as follows. The break initially results in a rapid blowdown of both steam generators. The steam generator depressurization initiates a rapid Reactor Coolant System (RCS) cooldown and depressurization, which results in a reactor trip on variable low pressure-temperature within the first few seconds of the accident. The reactor trip causes the main turbine stop valves to close, thereby isolating the affected steam generator from the unaffected steam generator. The affected steam generator continues to depressurize while the unaffected steam generator repressurizes. The main feedwater (MFW) pumps are tripped, all MFW valves are closed, and the turbine-driven emergency feedwater (EFW) pump is inhibited from starting, when the steam line break detection and mitigation circuitry is actuated on low steam generator pressure. The motor-driven EFW pumps start on main feedwater pump trip. The operator will manually trip all reactor coolant pumps (RCPs) on a loss of the subcooled margin. The operator will then manually isolate EFW flow to the affected steam generator to terminate the overcooling transient. EFW flow is automatically controlled to the unaffected steam generator to provide the secondary heat sink. The High Pressure Injection System (HPI) will actuate on low RCS pressure and will begin restoring RCS inventory. The operator will then throttle HPI flow to maintain pressurizer level to the normal post-trip level.

The steam line break accident is analyzed both with and without offsite power. The with offsite power maintained case analyzes end-of-cycle core conditions to maximize the positive reactivity addition resulting from the RCS cooldown and any resulting return-to-power. The without offsite power case analyzes beginning-of-cycle (BOC) core conditions to conservatively predict the approach to DNB as the reactor coolant pumps (RCPs) coast down. No credit is taken for the steam line break detection and mitigation circuitry since some of the components that actuate are non-safety grade. The non-safety grade Integrated Control System (ICS) is assumed to maintain the minimum post trip steam generator level, since this assumption has been demonstrated to be conservative relative to assuming no ICS control of MFW. Since MFW is available and controlling steam generator level to the ICS setpoint, EFW will not be actuated. The analysis methodology and the computer codes used in the analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Operator action to isolate MFW flow to the broken steam generator is credited at 10 minutes. The limiting single failure for the with offsite power analysis is the failure of a train of engineered safeguards that results in only one train of HPI. No single failure was identified which affects the results of the without offsite power analysis. The maximum worth control rod is assumed to remain in the fully withdrawn position.

The steam line break accident is considered to be a limiting fault. The acceptance criteria for this event are that the core will remain intact for effective core cooling and that the offsite doses will be within 100% of the 10CFR100 limits.

15.13.2 WITH OFFSITE POWER ANALYSIS

The steam line break accident with offsite power analysis is concerned with the magnitude of any post-trip return-to-power. A significant return-to-power with the presence of a stuck rod may challenge the DNB limit. The limiting scenario with respect to maximizing the overcooling and reactivity addition has been

9 determined to be the case with the ICS controlling MFW flow to the post- trip steam generator level
9 setpoint increased by an allowance for uncertainty. EFW is not actuated for this scenario. This limiting
9 scenario has been determined to bound scenarios with the ICS in manual control with no operator action,
9 which results in uncontrolled MFW flow and actuation of the EFW System. The duration of the analysis
9 is 10 minutes, which includes the core conditions of minimum DNB margin. The results of the analysis
9 are shown in Figure 15-40, Figure 15-41, Figure 15-42, Figure 15-43, Figure 15-157, Figure 15-158,
9 Figure 15-159, and Figure 15-160, and the sequence of events is given in Table 15-5.

9 The steam line break initially causes the pressure to decrease in both steam generators (Figure 15-40).
9 The reactor trips in 0.8 seconds. Break flowrates (Figure 15-41) for both steam generators rapidly
9 increase. After the turbine stop valves close, break flow from the unaffected steam generator stops. Break
9 flow from the affected steam generator decreases with decreasing pressure, and the unaffected steam
9 generator repressurizes and opens the turbine bypass valves and the first bank of main steam safety valves.
9 Both steam generators are nearly fully depressurized by the end of the simulation. The cooldown in the
9 affected loop is initially much more severe than in the unaffected loop, as shown in the cold leg and hot
9 leg temperature responses (Figure 15-42). The bulk of the RCS has cooled to approximately 270°F by
9 the end of the simulation.

9 The total, moderator, Doppler, boron and control rod reactivities are presented in Figure 15-43. The
9 negative reactivity insertion at the beginning of the transient is due to the reactor trip and control rod
9 insertion. The cooldown causes positive reactivity insertion due to the negative moderator and Doppler
9 coefficients. The core returns to a critical condition at approximately 140 seconds. Injected boron from
9 the HPI system and the CFTs reaches the core at approximately 160 seconds. The negative reactivity
9 inserted by the boron returns the core to a subcritical condition by approximately 200 seconds.
9 Subcriticality is maintained for the remainder of the simulation. The reactor power (Figure 15-157)
9 decreases rapidly on reactor trip. The thermal power generally follows the neutron power response. The
9 fluctuations in the heat flux are caused by flow surges in the core which result from flow degradation due
9 to two-phase conditions in the unaffected loop. A peak return-to-power of 13.09 %FP heat flux occurs
9 at approximately 160 seconds. RCS pressure (Figure 15-158) rapidly decreases until the affected loop and
9 reactor vessel head begin to saturate at approximately 4 seconds. After this time, RCS pressure continues
9 to decrease for the remainder of the simulation.

9 Core inlet mass flow (Figure 15-159) initially increases with time due to the decreasing RCS temperatures.
9 However, as the unaffected loop begins to void and RCP performance degrades, core inlet flow decreases
9 to approximately half of the initial flow. After the RCPs in the unaffected loop are tripped at 100
9 seconds, the flow oscillations diminish. The system analysis results and the core power distribution
9 (Figure 15-160) at the limiting DNB statepoint are input to the detailed core thermal-hydraulic analysis to
9 determine the limiting DNBR. The minimum DNBR at the peak return-to-power statepoint has been
9 determined to be 3.28. Therefore the core does not approach conditions for which DNB would occur,
9 and the core will remain intact for effective core cooling.

9 15.13.3 WITHOUT OFFSITE POWER ANALYSIS

9 The steam line break accident without offsite power analysis assumes a loss of offsite power coincident
9 with the break which trips the reactor and causes the RCPs to coast down. For this scenario the steam
9 line break accident is a loss of flow accident with a coincident depressurization. The minimum DNBR
9 statepoint occurs within the first few seconds of the RCP coastdown, therefore the duration of the analysis
9 is 10 seconds. Due to the loss of power, the MFW pumps will begin to coast down due to loss of the
9 condensate booster pumps. The results of the analysis are shown in Figure 15-161, Figure 15-162,
9 Figure 15-163, Figure 15-164, Figure 15-165, Figure 15-166 and Figure 15-167, and the sequence of
9 events is given in Table 15-48. The steam line break initially causes the pressure to decrease in both
9 steam generators (Figure 15-161). Once the main turbine stop valves close, the unaffected steam

generator repressurizes and opens the turbine bypass valves. The affected steam generator has depressurized to about 400 psig by the end of the analysis. The break flow response is similar to the with offsite power analysis. The cooldown in the affected loop is much more severe than in the unaffected loop, as shown in the cold leg temperature response (Figure 15-162). The increase in hot leg temperatures is caused by the flow coastdown. The affected loop hot leg temperature is slightly higher than the unaffected loop hot leg temperature due to the post-trip outsurge from the pressurizer. The RCS volumetric flow decreases for the duration of the simulation (Figure 15-163). The control rod insertion on loss of offsite power determines the core kinetics response (Figure 15-164). Due to the assumed BOC kinetics parameters and the short duration of the analysis, the moderator and Doppler reactivity feedback is negligible. The reactor neutron power decreases rapidly on reactor trip (Figure 15-165), with the thermal power responding slower due to the thermal delay. RCS pressure (Figure 15-166) rapidly decreases due to the effects of the overcooling from the steam line break and from the control rod insertion. As flow and primary-to-secondary heat transfer begin to degrade, RCS pressure stabilizes.

The system analysis results are input to the detailed core thermal-hydraulic analysis to determine the limiting DNBR. The minimum DNBR assuming a standard reference power distribution is 1.45, which is less than the design limit of 1.50. Consequently, DNBR margin may not exist, and a fuel pin census analysis is performed to determine if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. A range of pin radial peaks and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel pin in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the DNBR limit is exceeded. All fuel pins that exceed the DNBR limit are assumed to experience cladding failure and are counted in the source term for the offsite dose calculation. The results of the fuel pin census analysis for the steam line break accident without offsite power is that DNB margin exists for all of the fuel pins.

15.13.4 ENVIRONMENTAL CONSEQUENCES

A conservative consequences analysis is performed for the postulated double-ended break of a 36-inch main steam line. The rapid cool-down of the Reactor Coolant System (RCS) and the associated positive reactivity addition to the core do not lead to accident-induced fuel failures or breaches of the primary system pressure boundary. Therefore, environmental consequences can only arise from atmospheric releases of pre-existing RCS activity via primary-to-secondary leakage and of contaminated secondary system coolant.

Two postulated cases are analyzed:

Case 1: Equilibrium RCS iodine specific concentrations, at the technical specification limit, exist at the time of the accident. The primary activities for non-iodine isotopes bound the limits set by Technical Specifications. No iodine release rate spiking is assumed.

Case 2: Pre-existing iodine spike at the time the accident occurs. The reactor coolant concentrations are the maximum permitted for full power operation (50 times the normal equilibrium Technical Specification limit).

The secondary side coolant activity prior to the accident corresponds to limits set by Technical Specifications.

The initial conditions, boundary conditions and assumptions of the analysis are chosen to maximize the release of radionuclides to the environment by maximizing the stored energy in the primary system, the primary to secondary leakage, and the secondary-side pressurization. The following assumptions and parameters are used to calculate the activity release and offsite dose for the postulated large MLSB accident:

9 1. The reactor is assumed to be at the end of a 500 EFPD cycle with extended operation at 102% full
9 power (2619.4 MWt).

9 2. No core cladding ruptures or fuel melting occur during the accident.

9 3. Offsite power is maintained for the duration of the accident.

9 4. A pre-existing, 1 gpm primary-to-secondary leakage is assumed to be located in the affected steam
9 generator. This leakage is assumed to vary as the plant is cooled to cold shutdown (Mode 5). The
9 associated activity releases to the environment bound those corresponding to primary- to-secondary
9 leakage at the technical specification limits.

9 5. During the accident, credit is taken for depletion of the RCS fission product activities by radioactive
9 decay and by primary-to-secondary leakage.

9 6. All noble gases contained in the RCS coolant leaking to the OTSG secondary side are immediately
9 released to the atmosphere, with no retention in the secondary coolant.

9 7. The following iodine partition coefficients are assumed:

9 a) The steam generator steam/water interface iodine partition coefficient is 1.

9 b) The partition coefficient for main steam/auxiliary steam providing the motive force
9 in the condenser steam air ejectors (CSAEs) is 1.

9 c) The condenser partition coefficient is 10,000 for iodine entering the condenser and
9 then exiting via the CSAEs to the unit vent.

9 8. No credit is taken for either heat removal or iodine retention in the condenser once the turbine stop
9 valves close. Instead, the atmospheric dump valve associated with the unruptured main steam line is
9 used to cool the plant to cold shutdown (Mode 5).

9 9. Beginning at 70 minutes, the plant is cooled to cold shutdown (Mode 5) at a rate within the technical
9 specification limits that leads to conservative offsite doses.

9 10. SG steaming to the atmosphere ends at 2.4 hours with primary to secondary releases ending at 14.3
9 hours.

9 11. The primary coolant releases from the ruptured steam generator terminates once the RCS has been
9 cooled to cold shutdown (Mode 5) conditions and the RCS pressure is less than or equal to the
9 pressure in the secondary-side of the OTSGs.

9 12. The RCS is assumed to be cooled to cold shutdown conditions at the Tech Spec maximum
9 permissible rates.

9 13. No credit is taken for plate-out of iodine in the steam generator or steam lines.

9 14. Other parameters are listed in Table 15-54.

9 Prior to reactor trip and closure of the turbine stop valves at 0.8 seconds, both steam generators release
9 primary coolant and contaminated steam both to the condenser and through the break. Following
9 closure of the turbine stop valves, the OTSG on the unaffected steam line will be isolated from the faulted
9 OTSG. Subsequent atmospheric releases of fission products from the unfaulted OTSG occur primarily
9 from steam releases via the associated main steam safety valves (MSSVs) or atmospheric dump valve
9 (ADV). Post-trip primary-to-secondary leakage in the faulted OTSG is assumed to be released directly to
9 the environment until the plant is brought to cold shutdown (Mode 5), and the RCS is depressurized.
9 Main steam flows from the unfaulted OTSG to the station Auxiliary Steam System and the turbine driven
9 EFW pump are assumed to be isolated by 70 minutes.

9 Based on the foregoing model, the primary and secondary side releases may be calculated, as well as the
9 offsite doses. The doses are below the regulatory acceptance criteria of full 10 CFR 100 limits for each of
9 the above cases. The results are presented in Table 15-54.

9 15.13.5 CONCLUSIONS

9 The steam line break accident has been analyzed both with and without offsite power. The results of the
9 analysis show that DNBR margin exists. The results of the environmental consequences analyses are
9 within the 10CFR100 limits. All of the acceptance criteria are met.

15.13.6 REFERENCES

9 1. Deleted per 1999 Update
9 2. Deleted per 1999 Update
9 3. Deleted per 1999 Update
9 4. Deleted per 1999 Update
9 5. Deleted per 1999 Update
9 6. Deleted per 1999 Update
9 7. Deleted per 1999 Update
9 8. Deleted per 1999 Update
6 9. Deleted per 1996 Update
6 10. Deleted per 1996 Update
9 11. Deleted Per 1999 Update

15.14 LOSS OF COOLANT ACCIDENTS

15.14.1 IDENTIFICATION OF ACCIDENTS

A failure of the RCS pressure boundary will result in a loss of primary coolant inventory and the potential for the core to uncover. These hypothetical failures are considered to occur in all piping and components up to and including a double-ended rupture of the largest pipe in the system. If the core is not rapidly reflooded and long term heat removal established, decay heat will cause the fuel cladding to fail and release the fission product inventory. The ECCS is designed to deliver sufficient coolant to provide the necessary core decay heat removal for all credible LOCA's.

15.14.2 ACCEPTANCE CRITERIA

In order to judge the acceptability of the performance of the ECCS in mitigating a LOCA, the Final Acceptance Criteria specified in 10CFR50.46 require that the results of the LOCA analysis meet the following criteria.

15.14.2.1 Peak Cladding Temperature

The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

15.14.2.2 Maximum Cladding Oxidation

The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation. As used in this subparagraph total oxidation means the total thickness of cladding metal that would be locally converted to oxide if all the oxygen absorbed by and reacted with the cladding locally were converted to stoichiometric zirconium dioxide. If cladding rupture is calculated to occur, the inside surfaces of the cladding shall be included in the oxidation, beginning at the calculated time of rupture. Cladding thickness before oxidation means the radial distance from inside to outside the cladding, after any calculated rupture or swelling has occurred but before significant oxidation. Where the
9 calculated conditions of transient pressure and temperature lead to a prediction of cladding swelling, with or without cladding rupture, the unoxidized cladding thickness shall be defined as the cladding cross-sectional area, taken at a horizontal plane at the elevation of the rupture, if it occurs, or at the elevation of the highest cladding temperature if no rupture is calculated to occur, divided by the average circumference at that elevation. For ruptured cladding the circumference does not include the rupture opening.

15.14.2.3 Maximum Hydrogen Generation

The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

15.14.2.4 Coolable Geometry

Calculated changes in core geometry shall be such that the core remains amenable to cooling.

15.14.2.5 Long-Term Cooling

After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

Conformance with the acceptance criteria must be demonstrated in a LOCA analysis which is conducted within the guidelines of 10CFR50 Appendix K, "ECCS Evaluation Models." Appendix K outlines the assumptions and analytical methods which have been accepted by the Nuclear Regulatory Commission (NRC) for evaluating the consequences of LOCA. The ECCS evaluation model applicable to Oconee is detailed in the following section.

15.14.3 ECCS EVALUATION MODEL

15.14.3.1 Methodology and Computer Code Description

7 The large break LOCA (LBLOCA) evaluation model, which has been approved by the NRC, is detailed
7 in the topical report "BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam
7 Generator Plants" (Reference 40). The LBLOCAs are analyzed with the RELAP5/MOD2-B&W
7 computer code (Reference 38). The LBLOCA evaluation model has been shown to conform to the
7 requirements of Appendix K.

7 The RELAP5/MOD2-B&W code (Reference 38) solves the evolution of system hydrodynamics, core
7 power generation, and clad temperature response during blowdown for the large break LOCA. The
7 REFLOD3B code (Reference 4) is used to determine the length of the refill period and the flooding rates
7 during reflood. The CONTEMPT code (Reference 5) calculates the Reactor Building pressure response.
7 The BEACH code (Reference 39) is used with the output from REFLOD3B and CONTEMPT to
7 determine the fuel thermal and mechanical response and the PCT during the reflood period. The code
7 interfaces for the large break LOCA are shown in Figure 15-44 for cold leg breaks larger than 2 ft^2.

7 Cold leg break sizes between approximately 0.75 ft^2 and 2 ft^2 produce thermal-hydraulic behaviors that are
7 transitional in nature, having both large and small break characteristics. The smaller break sizes result in
7 slower transients for which no refill period exists. The smallest breaks may also begin reflooding the core
7 shortly after core flood tank flow begins. The analysis of break sizes in this range requires adjustments to
7 the nominal RELAP5-based LBLOCA evaluation model. These adjustments are described in Reference
7 40.

7 Hot leg breaks have many thermal-hydraulic similarities to the transitional breaks. There is no refill
7 period due to direct venting of core steam to the break. Core reflooding begins shortly after core flood
7 tank flow begins. Thus, the cold leg break LOCA methods are not suitable for analyzing these breaks.
7 The techniques used to analyze the hot leg breaks with RELAP5/MOD2-B&W are described in Reference
7 40.

The evaluation model which has been approved by the NRC for simulating the response of Oconee type
7 plants to a small break LOCA is detailed in the B&W topical report, "B&W's Small-Break LOCA ECCS
7 Evaluation Model" (Reference 32). The evaluation model consists of an integrated application of
7 computer codes that calculate the system response including the peak clad temperature (PCT). Each code
consists of models and assumptions which have been shown to be in accordance with Appendix K.

The CRAFT2 code (Reference 2), which is a modified version of the FLASH-2 code (Reference 3), solves
7 the evolution of system hydrodynamics and core power generation for the small break LOCA. The
7 THETAl-B code (Reference 6) is used with the output from CRAFT2, to determine the fuel thermal and

mechanical response and the PCT. For the small break LOCA (SBLOCA) which results in core
7 uncovery, the core mixture level is calculated by the FOAM2 code (Reference 7). The code interfaces for
7 the small break LOCA are shown in Figure 15-45.

15.14.3.2 Simulation Model

7 The RELAP5 LBLOCA nodalization is presented in Reference 40. A detailed nodalization of the
7 primary loop and reactor vessel is included. For break locations other than the pump discharge, the
7 nodalization is appropriately modified.

The SBLOCA CRAFT2 nodalization scheme is shown in Figure 15-49. This nodalization includes a revision to the nodalization given in Reference 1 which separated the original single volume representing the core, core bypass, upper plenum, and upper head, into two volumes representing the core - core bypass, and the upper plenum - upper head (Reference 9). Since the SBLOCA is a moderate transient, a less detailed model than that used for a large break can be utilized. All nodes use a bubble rise model and those flowpaths associated with the reactor vessel include a dual representation which allows for the prediction of counter-current flow. A change to the evaluation model was made in order to yield better agreement between the CRAFT2 and FOAM2 predicted steam escape rates. A bubble velocity multiplier of 2.38 is applied in the core and a multiplier of 2.0 in the remaining vessel volumes was incorporated (Reference 9).

As a result of NUREG-0737, Section II.K.3.30, the SBLOCA evaluation model has been modified (Reference 32). The modifications include a non-equilibrium pressurizer model, revised emergency feedwater model, two-phase RC pump model, and a more mechanistic steam generator model. The more mechanistic steam generator model includes a more detailed nodalization than is given in Figure 15-49.

15.14.3.3 Thermal Hydraulic Assumptions

Thermal hydraulic conditions and parameters are assumed in accordance with Appendix K.

15.14.3.3.1 Sources of Heat

7 For large break LOCA, the reactor is initially operating at 102 percent of 2,568 MWt, the maximum rated
7 power for the Oconee units.

7 For small break LOCA the reactor is initially operating at 102 percent of 2,772 MWt, the maximum rated power for an Oconee class plant. Core peaking factors are obtained from the analysis based on the
1 criteria of 10CFR50.46. Core stored energy and fuel temperatures are calculated using the TACO2 or
1 TACO3 code (References 10 and 35). Fission product decay heat is given by 1.2 times the ANS standard and decay of actinides is also assumed greater than the ANS decay curve. Direct moderator heating accounts for 2.7 percent of the fission energy released during the blowdown. Metal-water reaction is calculated using the Baker-Just equation without steam limiting. Heat transfer from non-fuel sources is accounted for, as is primary to secondary heat transfer.

15.14.3.3.2 Fuel Mechanical and Thermal Response

The detailed fuel response throughout the duration of the transient is predicted by the
7 RELAP5/MOD2-B&W and BEACH codes for large break LOCA and CRAFT2 and THETA1-B codes
7 for small break LOCA. Thermal expansion, elastic and plastic deformation, and the events leading to possible clad rupture are considered. Approved models for heat capacity and conductivity in the fuel, and gap conductance and heat transfer are used.

As a result of ongoing research programs, the NRC developed new models for fuel clad swelling and rupture which indicated that vendor evaluation models might be nonconservative (Reference 11). These
7 new models for cladding, swelling and rupture are described in NUREG-0630 and are incorporated in
7 Reference 40.

15.14.3.3.3 Blowdown Model

7 ECCS bypass is predicted to occur as long as the flow velocity is calculated to be sufficient to carry the
7 ECCS fluid away from the core. The end of blowdown is considered either when zero leak flow occurs or
7 when ECCS water starts entering the core. Friction and form loss factors account for system pressure
7 drops and compare well with measured plant data. Single-phase and two-phase pump models are derived
7 from homologous relationships.

7 Large Break LOCA Blowdown Model

7 Break flow is calculated using the Extended Henry-Fauske equation for qualities up to 0.0 at which time a
7 switch to the Moody correlation occurs. A range of discharge coefficients is evaluated in the break
7 spectrum analysis. The critical heat flux (CHF) correlations used are the BWC, BWCMV, Barnett, and
7 modified Barnett. In the low flow regime, a combination of the MacBeth and Griffith correlations is
7 used. Pre-CHF heat transfer uses the maximum of the Dittus-Boelter or Rohsenow-Choi correlations for
7 forced convection and a combination of the Chen, Thom, and Schrock-Grossman correlations for the
7 nucleate boiling and forced convection vaporization regimes.

7 The post-CHF heat transfer regimes include transition boiling, film boiling, and single-phase steam heat
7 transfer. For transition boiling, the correlation of McDonough, Milich, and King is used. The maximum
7 of the Condie-Bengston and Rohsenow-Choi correlations is used in the film boiling regime. The
7 single-phase heat transfer to steam correlation is the sum of a convective term and a radiation term. The
7 convection heat transfer is the maximum of the McEligot or Rohsenow-Choi correlations. The radiation
7 heat transfer is from the Sun correlation.

7 Small Break LOCA Blowdown Model

7 Break flow is calculated using the orifice equation for qualities up to 0.0 at which time a switch to the
7 Moody correlation occurs. The critical heat flux (CHF) correlations used are the B&W-2, BWC, Barnett,
7 and modified Barnett. Pre-CHF heat transfer uses the Dittus-Boelter correlation for forced convection,
7 the Thom correlation for nucleate boiling, and the Schrock and Grossman correlation for forced
7 convection vaporization (THETA1-B only). Post-CHF heat transfer does not permit use of nucleate
7 boiling heat transfer until that correlation gives a lower heat flux than transition boiling.

15.14.3.3.4 Post-Blowdown Model

The evaluation of the LOCA during refill and reflood is conservatively conducted assuming the minimum containment backpressure consistent with the Reactor Building Cooling Systems performance, the ECCS injection with the design single failure, and conservative containment initial conditions, volume, and heat
7 sink data. The REFLOD3B code calculates the heat transfer and hydraulic response with containment pressure input from CONTEMPT. During the refill period the core undergoes an adiabatic heatup. Steam venting and steam-water interaction, liquid entrainment, hot wall effects, and refill-reflood heat transfer are accounted for.

15.14.3.3.5 Availability of Reactor Coolant Pumps

Sensitivity studies have shown that for the large break LOCA the highest PCT results for the case with
7 reactor coolant pumps tripped. Therefore, for large break LOCA the pumps trip and coast down on a
7 loss of offsite power coincident with the break.

The SBLOCA has been analyzed assuming that the reactor coolant pumps trip and coast down coincident with reactor trip. This results in the coolant inventory change due to loss out the break and HPIS injection being reflected by the reactor vessel mixture level. The break size which resulted in the highest PCT was determined by a break spectrum analysis. This scenario was expected to represent the worst case SBLOCA, since if the reactor coolant pumps were running, the core would be cooled by pumping a
7 two-phase mixture through the core, and no heatup would occur. Studies (Reference 14) have shown that for certain SBLOCAs characterized by a limited range of break sizes and break locations, that a delayed reactor coolant pump trip at high system void fractions can result in extended core uncovery and consequences in excess of the 10CFR50.46 criteria. This constituted a new worst case scenario. This situation resulted in the implementation of operating procedures which instruct the operator to trip the reactor coolant pumps upon loss of subcooled margin (Reference 15).

15.14.3.3.6 ECCS Performance and Single Failure Assumption

The ECCS is comprised of two passive core flood tanks (CFT), each of which injects through its associated core flood line into the reactor vessel downcomer; three low pressure injection pumps separated into two trains which inject into separate core flood lines; and three high pressure injection pumps separated into two trains which split and inject into each cold leg. The ECCS configuration was analyzed
7 with the CRAFT2-based evaluation model to determine the worst single failure in addition to the
7 assumption of the loss of offsite power for each LOCA (Reference 33). Historically, the worst single failure for a LOCA is the loss of one bus of emergency power which results in the loss of one train of
7 HPI and one train of LPI. The failure of transformer CT-4 has been identified as a more limiting single
7 failure for the large break LOCA. The failure of transformer CT-4 results in a longer delay until delivery
7 of ECCS fluid to the RCS. However, two ECCS trains are available with this single failure. Reference 33 demonstrates that having two ECCS trains injecting at a later time is more limiting than having one
7 ECCS train injecting at an earlier time.

7 The Keowee hydro unit will start up and accelerate to full speed in 23 seconds or less (Section 6.3.3.3,
7 "Loss of Normal Power Source"). The failure of transformer CT-4 results in an additional 10 second
7 delay before power is available to the ECCS pumps. The time delay between breaker closure and
7 valve/pump motors operating at rated voltage/speed is 5 seconds. Thus, for the large break LOCA
7 analyses performed with the RELAP5-based evaluation model (Reference 40), the LPI valves will begin
7 to open at 38 seconds with a 15 second stroke time. Credit is taken in the analysis for flow through the
7 LPI valves while the valves are traveling to their full open position. Full LPI flow will be obtained within
7 53 seconds. Two ECCS trains are available with the single failure of transformer CT-4. However, only
7 one train of LPI flow is credited in the actual large break LOCA analyses (Reference 41).

7 For the limiting large break LOCA, the core heatup following blowdown is mitigated by core flood tank
7 injection. The time of PCT is prior to the actuation of pumped ECCS flow from the LPI and HPI
7 pumps. Flow from one LPI pump provides for the long-term cooling of the core. For smaller large
7 break LOCAs down to the transition break size of 0.75 ft^2, some HPI flow contributes to core cooling
7 prior to the time of PCT, but it is a small contribution relative to the core cooling provided by the core
7 flood tanks and the LPI pump. The PCTs for the smaller large break LOCAs have a large margin to the
7 2200°F acceptance criterion, and the small contribution of HPI flow to core cooling is not significant.
7 Although the flow from one HPI pump is assumed in the large break LOCA RELAP5 analyses, the
7 required core cooling can be provided by the core flood tanks and one LPI pump. HPI pumps are not
7 required for large break LOCA mitigation.

A SBLOCA does not progress as rapidly as a large break LOCA. Thus, for a SBLOCA, the timing of ECCS injection is not as significant as with a large break LOCA. For this reason, the worst single failure for a SBLOCA remains the loss of one bus of emergency power. With the selection of an adverse break location, one half of the available HPI train would inject into the broken loop. With these assumptions
7 the ECCS is reduced to the two CFTs, one LPI train, and one half of one HPI train. For a core flood
7 line break, the available equipment are one core flood tank and HPI train. The SBLOCA analyses
7 assume a 35 second delay until full ECCS flow is delivered to the RCS. An evaluation performed in
7 Reference 33 demonstrates that an increase in the ECCS delay time from 35 to 48 seconds is acceptable
7 for SBLOCA.

For the SBLOCA which does not depressurize to below the core flood tank setpoint (600 psig), only one half of one HPI train was available if the break is assumed to be in the cold leg pump discharge. This was identified as an unacceptable scenario (Reference 16). In order to deliver the required HPIS flow of 350 gal/min at 600 psig (Reference 17), the HPIS was modified to allow cross connecting of the pump discharges in order to balance the flow from two HPI pumps into the four injection locations (Reference
6 18, 19). This manual realignment of the HPIS is assumed to be completed within ten minutes of HPIS
6 actuation.

15.14.4 BREAK SPECTRUM ANALYSIS

7 The LOCA analysis has been performed using the NRC-approved evaluation models in accordance with 10CFR50 Appendix K for a complete spectrum of break sizes and locations.

7 This analysis is given on a generic basis for the CRAFT2-based evaluation model for an Oconee type plant in BAW-10103A Rev. 3, "ECCS Analysis of B&W's 177-FA Lowered-Loop NSS" (Reference 20).

The reference analysis was revised and expanded to account for an improved system loop pressure distribution (Reference 21), to change the location of the worst small break from the cold leg pump suction to the pump discharge (Reference 9), and to examine the impact of a delayed reactor coolant pump trip on SBLOCA (Reference 14). The effects of these reanalyses on the reference analysis will be presented in the following sections.

15.14.4.1 Large Break LOCA

7 Using the CRAFT2-based evaluation model (Reference 1), a spectrum of large breaks from 0.5 ft^2 up to and including the cross sectional area of the largest pipe in the system was analyzed for both double-ended and longitudinal split breaks in all locations. The methodology used to identify the worst break was as follows. A double-ended break with discharge coefficient C_D = 1.0 was analyzed at the hot leg, cold leg pump suction, and pump discharge. The cold leg pump discharge was determined to be the worst break location. The break size was then varied from 0.5 ft^2 to the geometric maximum for both double-ended
7 and split breaks.

7 The CRAFT2 LOCA evaluation models have a transition from the large break LOCA evaluation model
7 to the small break LOCA evaluation model at a break size of 0.5 ft^2. The RELAP5 large break LOCA
7 analyses have replaced the CRAFT2 large break analyses. The generic break spectrum studies performed
7 with the RELAP5 evaluation models have selected the transition break size to be 0.75 ft^2, based on the
7 onset of the occurrence of early cladding DNB during the blowdown phase. Both of these break
7 spectrum studies have shown that the phenomena in the transition break size range are predicted to be
7 similar, and that the PCTs in the vicinity of the transition break size are non-limiting.

7 The break spectrum analysis was also performed using the RELAP5-based evaluation model for the
7 generic raised loop design (Reference 40) for break sizes ranging from 0.75 ft^2 up to and including the

7 cross sectional area of the largest pipe in the system. Breaks that were clearly shown to be non-limiting in
7 the generic break spectrum analysis were not reanalyzed for the Oconee-specific break spectrum. A
7 double-ended break with discharge coefficient C_D = 1.0 was analyzed at the cold leg pump discharge and
7 cold leg pump suction. The cold leg pump discharge was determined to be the worst break location.
7 This break location was further analyzed for a double-ended break with discharge coefficients of C_D = 0.8
7 and C_D = 0.6. A split break at the cold leg pump discharge was also analyzed. The results of these
7 analyses are shown in Table 15-6 and Figure 15-50. A symmetric power shape with an axial peaking
7 factor of 1.7 and a peak linear heat rate of 17.5 kW/ft is assumed.

The worst break was identified as the double-ended cold leg break at the pump discharge with C_D = 1.0.
7 Using the RELAP5-based evaluation model (Reference 40), this break of 8.55 ft^2 area yielded a predicted
7 PCT of 1957°F and a maximum local metal-water reaction of 2.02 percent. The same break size at the
7 pump suction showed a predicted PCT of 1830°F and a maximum local metal-water reaction of 1.54
7 percent. The range of break sizes smaller than the full area double-ended break at the pump discharge all showed less severe consequences.

7 A series of large breaks are analyzed from an initial condition where three reactor coolant pumps are in
7 operation. Three possible break locations associated with this mode of operation were identified.

9 An evaluation was made using the RELAP5-based evaluation model on a generic basis for a raised-loop
7 plant (Reference 40). Breaks were analyzed with the idle pump simulated in the intact loop, broken leg,
7 and intact leg of the broken loop. The case with the idle pump in the broken leg was determine to be
9 limiting. Thus, a double-ended break with the idle pump in the broken leg and a C_D = 1.0 was analyzed
7 for Oconee using the RELAP5-based evaluation model with three pumps. This analysis, which was
7 performed at 80 percent FP with a moderator temperature coefficient of +1 pcm/°F, was shown to be
7 less limiting than the 100 percent FP case with a moderator temperature coefficient of 0 pcm/°F
7 (Reference 41).

15.14.4.2 Limiting Linear Heat Rate Analysis (LOCA Limits)

The large break spectrum analysis was performed using an axial peaking factor of 1.7 and a peak linear
7 heat rate of 17.5 kw/ft in order to determine the worst case break size and location using the
7 RELAP5-based evaluation model. For the limiting power shape or LOCA limits analysis, the location of
7 the 1.7 axial peak was varied along the length of core at the midpoints between the spacer grids nearest
7 the 2,4,6,8, and 10 feet elevations. A LOCA simulation of the worst case break was run for each power shape case. Then, for each case a maximum allowable linear heat rate which results in a core thermal response within the acceptance criteria of 10CFR50.46 was determined. The results of these analyses are
7 presented in Reference 41.

7

7 The LOCA linear heat rate limits as a function of elevation and burnup are shown in Figure 15-111 and
7 Figure 15-112. Plant operation within these limits assures that the 10CFR 50.46 acceptance criteria are
7 not exceeded.

2 LOCA limit analysis values for MK-B9 fuel are given in Table 15-27, along with a time sequence of
7 events for ECCS equipment. These results indicate a maximum PCT of 1989°F and a local metal water
7 reaction rate of 2.73 percent. Results for the MK-B9 fuel are presented only for burnup greater than
7 28,000 MWd/mtU since this fuel type is only present in Oconee cores as once- and twice-burned fuel.
7 The LOCA limit analysis values for MK-B10T fuel are given in Table 15-31. These results indicate a
7 maximum PCT of 2024°F and a local metal water reaction rate of 3.04 percent. LOCA limit analyses

have also been performed for demonstration lead test assemblies for the MK-B11 fuel design. These limits and the results of the analyses are not presented in detail due to their limited applicability.

15.14.4.3 Small Break LOCA

The SBLOCA is considered to be those break sizes less than 0.5 ft^2 and greater than the capacity of the normal makeup system. This corresponds to a minimum break size of approximately 0.0008 ft^2 with letdown flow isolated or 0.0004 ft^2 assuming normal letdown. In addition to the cold leg break locations, the HPI line break and core flood line with a maximum break size of 0.44 ft^2 were considered. The reference analysis considered three cases; the 0.44 ft^2 core flood line break, the 0.5 ft^2 pump discharge break, and the 0.04 ft^2 pump suction break since it had been previously determined to be the limiting small break (Reference 22). The results of these analyses determined that the core remained covered and assured that the criteria were met.

Subsequent evaluations determined that the worst case small break should be at the pump discharge rather than the pump suction. A break at the pump discharge could result in one half of the HPI going out the break, and an insufficient flow rate would be delivered to the vessel thereby uncovering the core for an extended period of time. As described in Section 15.14.3.3.6, "ECCS Performance and Single Failure Assumption," the HPIS was modified in order to deliver a higher flowrate. Additional analyses of SBLOCA were performed taking credit for operator action to align HPIS flow to both loops within ten minutes (Reference 9). The HPI flow rates assumed in core flood line, RCP discharge, and HPI line small break LOCA analyses are given in Table 15-28, Table 15-29, and Table 15-30, respectively. HPI flow rates are obtained from Reference 37. Break sizes of 0.04, 0.055, 0.07, 0.085, 0.10, and 0.15 ft^2 were performed at the pump discharge to supplement the reference analyses. Two modifications to the evaluation model were also included in the analyses. The results of the analyses showed that minor core uncovery occurred for the 0.055, 0.07, and 0.085 ft^2 breaks. The worst case PCT resulting from the 0.07 ft^2 break was 1092°F.

The SBLOCA has been analyzed assuming that the reactor coolant pumps trip and coast down on reactor trip. With no forced flow the liquid in the system would collapse to the lower elevations and an inner vessel mixture level could be tracked to determine the occurrence of core uncovery. For cases in which the pumps remained running, the circulation of the two-phase mixture provided adequate core cooling. Subsequent evaluations of the effect of a delayed pump trip revealed that a pump trip at high system void fractions would result in a collapsed mixture level well below the top of the core (Reference 14). This situation could only occur for a limited range of break sizes and a certain time window when pump trip would be unacceptable. In order to avoid an inadvertent pump trip in the time window, operating procedures were revised to instruct the operator to trip the reactor coolant pumps on loss of primary system subcooled margin (Reference 15). Analyses have shown that this action will prevent the criteria of 10CFR 50.46 from being exceeded for any SBLOCA.

The SBLOCA evaluation model has been revised due to NUREG-0737, Section II.K.3.30. NUREG-0737, Section II.K.3.31 requires that analyses are performed with the revised evaluation model to show compliance with 10CFR 50.46. Compliance with 10CFR 50.46 is demonstrated by a qualitative assessment of the SBLOCA spectrum and then a quantitative evaluation of the critical break sizes. The analyses documented in Reference 29 demonstrate that the previous SBLOCA evaluation model predicts more conservative results than the revised SBLOCA evaluation model. Therefore, analyses performed with the previous version of the SBLOCA evaluation model remain bounding.

5 15.14.5 EVALUATION OF NON-FUEL CORE COMPONENT STRUCTURAL 5 RESPONSE

The temperature transient in the core can produce significantly higher than normal temperatures in components other than fuel rods. Therefore a possibility of eutectic formation between dissimilar core materials exists. Considering the general area of eutectic formation in the entire core and reactor vessel internals, the following dissimilar metals are present, with major elements being in the approximate proportions shown:

Type-304 Stainless Steel

19% chromium

10% nickel

remainder iron

Control Rod Poison Material

80% silver

15% indium

5% cadmium

Zircaloy-4

98% zirconium

1-3/4% tin

Inconel

53% nickel

19% chromium

3% molybdenum

5% Nb-Ta

1% titanium

0.5 % aluminum

remainder iron

9 All these alloys have relatively high melting points (≥ 2,300°F) except those for silver, cadmium, and indium. The melting point of the silver-indium-cadmium alloy is about 1,470°F.

The binary phase diagram indicates that zirconium in the proportion 75 to 80 percent has a eutectic point with either iron, nickel, or chromium at temperatures of approximately 1,710, 1,760, and 2,380°F, respectively. If these dissimilar metals are in contact and if those eutectic points are reached, then the materials could theoretically melt even though the temperature is below the melting point of either material taken singly.

9 The Mk-B10 through Mk-B10L use Zircaloy-4, rather than inconel, for the intermediate spacer grids.
9 Only the end grids are made of inconel and these grids are outside of the active fuel region. Therefore, the

9 current assembly designs are less susceptible to this phenomenon than older designs, which had inconel
9 grids at each location.

During the experimental test program referred to above, B&W conducted experimental tests in which
7 specimens of Zircaloy-4 tubing in contact with sections of INCONEL 718 spacer grids material were subjected to a thermal transient closely approximately that of the clad hot spot following a LOCA. These tests verified that the eutectic reaction is limited to the small region of contact between the clad and the spacer grid tips (dimples), and that it terminates as these materials melt at the point of contact. Both the clad and the grid material maintained their structural integrity because the amount of material involved was small and melting was localized.

Another area of dissimilar metal contact is that of a zirconium guide tube with the stainless steel cladding of the control rod. To determine whether the temperatures in the control rod following a LOCA could become high enough to approach either the temperature required for possible eutectic formation between the clad and the guide tube or the melting temperature of the Ag-In-Cd alloy, the thermal performance of a control rod assembly following a LOCA was examined analytically. A conservative approach was taken in this analysis. In spite of the fact that the core flow is as high or higher than normal core flow during the first two seconds following the rupture, normal steady-state cooling of a control rod is assumed. In two seconds, the core power is essentially down to decay heat levels. However, the following assumptions were made.

1. The average core power after two seconds is 8 percent of ultimate power and remains at this level.
2. All decay heat is absorbed in the core and 50 percent of the decay heat is in the form of gamma rays available for absorption in the control rod. By ratioing the control rod density to the average core density, an average energy deposition rate of 8.50 W/cc in the control assemblies was obtained.
3. The maximum activation product energy in the control rod itself was estimated to be 2.99 W/cc.
4. The highest energy deposition rate at the decay heat level was assumed to be the average times the ratio of peak-to-average power, or 36.18 W/cc.
5. An adiabatic heatup of the control rod with a heat rate of 36.18 W/cc was assumed until the water level reached the point in the core at which the highest peak-to-average power occurs.
6. The temperature of the control alloy is approximately 650°F at the time the rod is assumed to be insulated (2 sec).

Using the assumptions above, the average temperature of the Ag-In-Cd goes up to 1,035°F, at which time the water level in the core reaches the elevation of the hottest spot on the control rod. The temperature of the rod then rapidly decreases.

The lowest temperature for a eutectic formation is that for Zr-Fe, which occurs at 1,710°F. Therefore, the integrity of the control rod assemblies is maintained during and following a LOCA.

2

2 15.14.6 CONFORMANCE WITH ACCEPTANCE CRITERIA

7 The NRC-approved ECCS Evaluation Models used for the LOCA analysis for Oconee class plants have
7 been shown to be within the guidelines of 10CFR50 Appendix K. These models have been used to perform detailed sensitivity studies to assure that any adverse phenomena are identified and adequately addressed. These analyses have demonstrated that the consequences of hypothetical LOCA's up to and including a double-ended break of the largest pipe in the RCS are within the limits prescribed in 10CFR50.46, as follows:

15.14.6.1 Peak Cladding Temperature

7 The maximum peak cladding temperature was calculated to be 2024°F, which is less than the 2200°F limit.

15.14.6.2 Maximum Cladding Oxidation

7 The maximum local metal-water reaction was calculated to be 3.04 percent, which is less than the 17 percent limit.

15.14.6.3 Maximum Hydrogen Generation

6 The worst case core average hydrogen generation was calculated to be less than the 1 percent limit.

15.14.6.4 Coolable Geometry

Changes in core geometry due to thermal and irradiation effects and mechanical loading have been calculated and show that no gross core blockage or disfiguration will occur. The core will maintain a coolable geometry.

15.14.6.5 Long-Term Cooling

Subsequent to the blowdown, refill, and reflood phases of a LOCA, long-term cooling to remove core decay heat for an extended period of time must be established. The ECCS is designed to perform this function. Operator action is assumed to be available fifteen minutes following a LOCA. Several operational modes are available to provide the necessary cooling and also to assure that adequate coolant
6 circulation exists to prevent any concentration of boric acid in a region of the RCS (Refer to Section
6 6.3.3.2.1, "Boron Precipitation Evaluation"). Redundancy in the design of the ECCS and multiple available flowpaths for removing core heat provide for sufficient long-term cooling.

15.14.7 ENVIRONMENTAL EVALUATION

The evaluation of the environmental consequences for the LOCA includes the assumption that one percent of the fuel rods in the core have been defective prior to the initiation of the accident. This results in the coolant fission product inventory given in Table 15-14 (Reference 28) for the worst time in life (up to 400 EFPD) for each isotope. The fission product release to the Reactor Building includes the coolant activity plus the gap activity from all fuel rods. The total core gap activities are given in Table 15-4.

Of the iodine released, 50 percent is assumed to plate out and the other half is assumed to remain in the Reactor Building atmosphere where it is available for leakage. No credit is taken for removal of airborne iodine by the Reactor Building Spray System (RBSS). To facilitate environmental dose calculations, all isotopes of iodine have been equated into dose equivalent curies of iodine-131. The dose equivalency factor is determined by considering the concentration and specific dose of each iodine isotope present over the period of interest. The iodine dose to the thyroid per curie is obtained from the values given in TID-14844. The iodine activity released to the reactor building is 1.43×10^6 dose equivalent curies of iodine-131.

While the Reactor Building leakage rate will decrease rapidly as the pressure decays, the leakage is assumed to remain constant at the rate of 0.25 percent of Reactor Building volume per day for the first 24 hrs. Thereafter, since the Reactor Building has returned to nearly atmospheric pressure, the rate is assumed to be reduced to 0.125 percent of the Reactor Building volume per day and to remain at this value for the duration of the accident.

It is assumed that 50 percent of the Reactor Building leakage will go into the penetration rooms which will be maintained at a negative pressure. The atmosphere in these rooms is discharged through charcoal filters to the unit vent. The charcoal filters are assumed to be 90 percent efficient for iodine removal. The remaining 50 percent of the Reactor Building leakage is assumed to escape directly to the atmosphere. By this method a maximum of 55 percent of the iodine released from the Reactor Building is ultimately released to the atmosphere. Atmospheric dilution of the leakage discharged from the unit vent is calculated using the elevated release dispersion factor of 3.35×10^{-5} sec/m^3. Dilution of the other leakage from the Reactor Building is calculated using the ground release dispersion factor of 1.16×10^{-4} sec/m^3. A breathing rate of 3.47×10^{-4} m^3/sec is assumed for the 2 hr. exposure. For the 30-day exposure, a breathing rate of 2.32×10^{-4} m^3/sec is assumed.

The total integrated thyroid doses resulting from this LOCA fission product release are 5.0 rem for the 2 hr. exposure at the 1 mi exclusion distance, and 5.5 rem for the 30-day exposure at the 6 mi low population distance. The corresponding whole body doses are 0.01 rem and 0.01 rem.

15.14.8 CONCLUSIONS

7 A complete spectrum of LOCAs have been conservatively analyzed with the NRC-approved evaluation models which conform to 10CFR50 Appendix K. The results of these analyses meet the acceptance
6 criteria of 10CFR50.46. The off-site environmental consequences are within the dose limits of 10CFR100. Therefore, the consequences of all design basis LOCAs have been shown to be acceptable.

15.14.9 REFERENCES

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15.15 MAXIMUM HYPOTHETICAL ACCIDENT

15.15.1 IDENTIFICATION OF ACCIDENT

The analyses in the preceding sections have demonstrated that even in the event of a LOCA accident, no significant core melting will occur. However, to demonstrate in a still more conservative manner that the operation of a nuclear power plant at the proposed site does not present any undue hazard to the general public, a maximum hypothetical accident (MHA) involving a gross release of fission products is evaluated. No mechanism whereby such a release occurs is postulated, since this would require a multitude of failures in the engineered safeguards which are provided to prevent such an occurrence. Fission products are assumed to be released from the core as stated in TID-14844, namely, 100 percent of the noble gases, 50 percent of the halogens, and 1 percent of the solids. Further, 50 percent of the iodines released to the Reactor Building are assumed to plate out. The Reactor Building Spray System is credited with removal of a portion of the remaining iodine from the building atmosphere. Other parameters such as meteorological conditions, iodine inventory of the fuel, Reactor Building leak rate, etc., are the same as assumed for the LOCA. The total core fission product inventory of interest is given in Table 15-15 (Reference 1).

15.15.2 ENVIRONMENTAL EVALUATION

The meteorological model employed is the same used in the LOCA analysis. The Reactor Building leak rate is assumed to be 0.25 percent per day by volume for the first 24 hrs, and then 0.125 percent per day for the next 29 days. The other assumptions are consistent with TID-14844.

The direct dose to the whole body following this accident is insignificant as shown in Figure 15-80. The total integrated thyroid doses are 167 rem for the 2 hr exposure at the 1-mi exclusion area boundary, and 74.1 rem for the 30-day exposure at the 6-mi low population zone distance. The corresponding whole body doses are 1.58 rem and 0.37 rem. These dose consequences are within the 10CFR 100 limits. A summary of the dose consequences for all transients and accidents is given in Table 15-16. These doses are revised to account for the effects of high burnup reload core designs (References 1, 2).

15.15.3 EFFECT OF WASHOUT

To provide a further evaluation of the suitability of the site, the effects of washout on surrounding drinking water reservoirs following the MHA are analyzed. Calculations are made for the case of continuous rain lasting 24 hr covering the general area of the reservoir and the site. The maximum washout rate as a function of distance is calculated from the following equation (Reference 3):

$$\omega_{max} = \frac{Q_o \, e^{-(y^2/2\sigma_y^2)}}{x e \sigma_y \sqrt{2\pi}}$$

where

ω_{max} = maximum washout rate $\left(\frac{Ci}{sec - m^2}\right)$

x = downwind distance (m)

σ_y = horizontal dispersion (m)

y = crosswind distance from plume axis (m)

Q_o = release rate ($\frac{Ci}{sec}$)

The equation above is conservative since the results do not consider the wind speed or vertical distribution in the cloud. The wind direction is assumed to remain towards Lake Keowee for the 24 hr period with the plume center lines uniformly distributed over this section. Washout is assumed to occur under neutral stability conditions, Pasquill D, which is typical for a rainy day.

The average release rate from the Reactor Building during the 24-hr period following the accident is 0.37 equivalent curies of iodine-131 per sec. Using the above equation, the maximum iodine washout is calculated by assuming that all of the iodine that has washed out remains in the surrounding reservoir and is not affected by runoff. The average number of curies in the reservoir during a one-year period is reduced by a factor of 0.0318 due to the natural decay of iodine. Assuming that this activity mixes in the reservoir and that an adult drinks 0.8 m^3 per year (Reference 4) of the contaminated water, the total dose to the thyroid has been calculated using the methods of TID-14844. The nearest drinking water intake is approximately two miles from the site. At this distance, the total integrated one-year ingestion dose to the thyroid is 1.0 rem. This dose is well below the limits of 10CFR 100.

15.15.4 EFFECTS OF ENGINEERED SAFEGUARDS SYSTEMS LEAKAGE

An additional source of fission product leakage during the maximum hypothetical accident can occur from leakage of the engineered safeguards systems external to the Reactor Building during the recirculation phase for long-term core cooling. A detailed analysis of the potential leakage from these systems is presented in Section 6.1.6, "Engineered Safeguards Materials." This leakage is less than the SLC 16.6.4, "Low Pressure Injection (LPI) System Leakage," limit of 2 gallons per hour (gph). Some of this leakage will flash into steam.

It is assumed that the water being recirculated from the Reactor Building sump through the external system piping contains 50 percent of the core saturation iodine inventory. This is the entire amount of iodine released from the RCS. The assumption that all of the iodine escaping from the RCS is absorbed by the water in the Reactor Building is conservative since much of the iodine released from the fuel will be plated out on the building walls. It is assumed that all the iodine contained in the water which is flashed is released to the Auxiliary Building atmosphere. Iodine will also be released from the remaining water, but the total released from both sources is estimated to be less than 5 %.

The Auxiliary Building is ventilated and discharges to the unit vent. The activity is assumed to be continuously released from the unit vent during the recirculation phase (which does not start until 30 minutes into the event). Atmospheric dilution is calculated using the 2-hr release dispersion factor of 0.00022 seconds per cubic meter. The total integrated dose to the thyroid from this activity is 1.78 rem for 2-hr exposure at the 1 mile exclusion distance. The integrated dose to the thyroid for a 30 day exposure at the 6 mile low population zone boundary is 1.48 rem. Combined with other sources of exposure during a maximum hypothetical accident, this is within the 300 rem guidelines specified in 10 CFR Part 100.

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15.16 POST-ACCIDENT HYDROGEN CONTROL

15.16.1 INTRODUCTION

The purpose of this section is to summarize the analyses performed to:

1. Evaluate the hazard caused by hydrogen generation following a LOCA.
2. Evaluate the acceptability of hydrogen recombination as a method for controlling the Reactor Building hydrogen concentration.

In this section the potential for radiolytic hydrogen generation including the dose, or energy deposited in the coolant following the accident, and the basis for the selection of the hydrogen generation constant ("G" value) is analyzed. Since the FSAR analyzes the potential zircaloy-water reaction in other sections, this analysis is not presented herein and a 5 percent zirc-water reaction is assumed in the reference case described in subsequent sections. The potential for hydrogen generation from a zinc-boric acid reaction when borated water spray solution contacts galvanized steel and aluminum in the Reactor Building at the post-accident temperature is also considered. The analysis shows that the radiolytic hydrogen generation rate plus the hydrogen contributed by the zircaloy and other reactions does not result in unacceptable hydrogen concentrations until 310 hr after the initiation of the LOCA.

Post-accident Reactor Building hydrogen concentration is controlled by the use of the Thermal Hydrogen Recombiner. Air is drawn from the reactor building at a flow of greater than 50 scfm to the recombiner. There the air is heated to approximately 1340 deg. F and passed through a reaction chamber causing hydrogen and oxygen molecules to recombine into water vapor. The effluent from this process then flows back to the reactor building. Since all process gas is returned to the reactor building, no release of radioactive material is made to the environment and therefore the hydrogen concentration can be reduced without increasing the radiation dose to the public.

Regulatory Guide 1.7 "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident" has been referenced in several sections of this analysis. Even though the Regulatory Guide has been used for guidance and information, Oconee is not committed to Regulatory Guide 1.7.

15.16.2 POST-ACCIDENT HYDROGEN GENERATION

15.16.2.1 Radiolytic Hydrogen Generation

15.16.2.1.1 Sources of Radiation

The radiation sources which contribute to the energy absorbed by the coolant following an accident are shown in Table 15-17. For the LOCA the only significant amount of radiation comes from sources in and near the core. In addition to the core sources, the contributions from the gases in the Reactor Building atmosphere, and the fission products in the coolant water itself are also considered. Table 15-18 shows the assumption used in the calculation of the energy deposited in the solution described in the following section.

Figure 15-82 shows the flow path of the post-accident ECCS in the long-term recirculation mode. Following a LOCA, the fluid for the RBSS and the ECCS is supplied from the borated water storage tank

(BWST). After the BWST is empty, coolant is then circulated from the Reactor Building sump through the LPIS to the reactor vessel.

The activity levels of the individual fission product nuclides were determined with B&W's proprietary digital fission product code. This digital code computes the activity of more than 200 fission product nuclides from one or two fissionable materials as a function of reactor operating history. One hundred time steps can be used in the code, and at each time step the program will print the individual nuclide activity along with the total gamma source strengths from all nuclides for each of six gamma energy groups.

The activity of the Np-239 and U-239 was obtained using the maximum neutron capture rates that occur in U-238 at any time during a core cycle. Sources from the activated clad and structural materials were calculated assuming saturation activity of these components and using lifetime average neutron fluxes in the core.

15.16.2.1.2 Calculation of Absorbed Energy

Table 15-18 summarizes the assumption made in calculating the energy absorbed by the coolant. In a LOCA all of the absorbed energy comes from sources in and near the core with the greatest fraction coming from fission product decay. The energy from fission product decay is about equally divided between gamma rays and beta particles. To determine the energy deposited in the solution by beta particles, the fuel pellets were subdivided into concentric cylindrical source shells, 10 mils in thickness. The amount of beta energy that was transmitted through the fuel cladding was calculated for each of these source shells. These calculations were performed for each fission product nuclide. It was assumed that all of the energy that penetrated the clad was absorbed by the water. The integrated beta energy between 10 and 3,000 hr after the LOCA was only two to three percent of that from the gamma rays. Nearly all of the beta energy is absorbed by the oxide and cladding.

For gamma rays the fission product source strengths were taken from the output of the fission product code and the gamma sources from U-239 and Np-239 were added to the various energy groups to obtain the total core source strengths. Energy deposition rates to the solution at various times were then calculated for each of the six gamma energy groups. Since these sources contribute most of the energy received by the solution, this calculation was checked using three techniques, all based on the assumption of a homogeneous core with a uniform average source distribution.

First, the amount of energy produced per unit volume of core was assumed to equal the amount of energy absorbed per unit volume. The distribution of absorbed energy between the cooling water and the remainder of the core was found by a ratio of the energy absorption coefficient of water to that of the homogenized core for each of the energy groups. In the second technique a receiver point was chosen at the center of the core. The energy absorption rate was calculated at this location with a point kernel integration code. The absorption at all other points in the core was assumed to be in the same as that at this point. For the third calculation the core was represented as an infinite homogeneous medium and the flux equations for an infinite slab were used to calculate the absorbed energy. These latter two calculations require the use of energy absorption buildup parameters for the homogenized core. A comparison between the mass and energy absorption coefficients for the core with those of various materials showed that the coefficients for lead matched those of the core quite well. The energy absorption buildup factors for lead were thus incorporated into the flux equations using the Taylor form of the buildup.

The total energy deposited in the solution was obtained by graphical integration of the absorption rate curves. Figure 15-84 shows the energy absorbed by the solution as a function of time following the LOCA. The results have been presented in terms of the energy absorbed by the solution rather than in dose units. The reason is that dose is a measure Absorbed Energy of energy absorbed per unit mass of

material. Consequently, whenever the volume or mass of the emergency core cooling solution changes, the dose changes. The generation of hydrogen, however, is a function only of the energy absorbed by the solution and does not change simply because the mass of the solution changes.

The curve shown in Figure 15-84 includes all the sources previously mentioned, fission product gammas, fission product betas, Np-239 and U-239, and activated structural materials. Also included is the energy absorbed by the water outside the core from sources inside core. This was determined by computing the spatial variation of the gamma fluxes in the water outside the core and integrating over the water volume. This contributed between 3 and 4 percent of the total energy absorbed. The activated cladding and other core hardware sources yield deposited energy which is only a fraction of a percent of that from other sources. The greatest amount of absorbed energy comes from the fission product and Np-239 gamma rays; these contribute approximately 95 percent of the total energy.

In addition to the core sources, 100 percent of the noble gases in the Reactor Building atmosphere, 50 percent of the halogens and 1 percent of the solids in the cooling water must also be considered.

In the Reactor Building atmosphere the activity levels and beta and gamma yield data for the noble gases were used to compute the individual beta and gamma source strengths for each nuclide. These sources were distributed uniformly throughout the free air volume of the Reactor Building. For beta particles the energy absorbed per unit volume of air was assumed to be equivalent to that produced per unit volume. For gamma rays the absorbed energy was computed at a point in the center of the Reactor Building and it was assumed that all other points in the building received this same energy. The gamma flux was calculated with a point kernel integration code. No credit was taken for attenuation by shielding by structures within the Reactor Building.

For the 50 percent halogens and 1 percent solid fission products in the cooling water, it was assumed that all of the energy produced by these sources was absorbed in the water. The absorbed energy from the halogens was computed for each nuclide using the individual beta and gamma yields. The contribution from the 1 percent solids was obtained by taking 1 percent of the total fission product decay heat curve and depositing this quantity of energy to the coolant.

As can be seen in Figure 15-84, initially the energy is controlled by the fission products in the cooling water. However, by 100 hr the sources in the core have taken over and continue to control as time increases. The contribution from the noble gases in the building atmosphere does not show up on the graph - this was insignificant in comparison to the other sources.

Since the core sources, and in particular the fission product gammas, contribute most of the energy to the solution, a comparison has been made between the decay heat gamma sources calculated by B&W with that published by Shure (Reference 1). Figure 15-85 shows the integrated gamma decay heat (fission products plus U-239 and Np-239) between 10 and 3,000 hr decay time following 620 days irradiation time from the two methods. Over the time span of interest for hydrogen generation (100 - 1,000 hr), they are in excellent agreement.

15.16.2.1.3 Radiolytic Hydrogen Generation

The hydrogen generation rates from the radiolytic decomposition of water were calculated utilizing the data presented in Figure 15-84 and a hydrogen generation constant ("G" value) equal to 0.45 molecules of hydrogen per 100 ev of energy absorbed by the fluid in the core region.

In the LOCA the integrated energy absorption by the sump solution is small, and this has been lumped with the core energy and a single hydrogen generation constant has been used. Under the Design Basis Accident (DBA) conditions, when the energy absorption in the sump region is significant, as a result of the assumed sources, a "G" value of 0.3 molecules of hydrogen per 100 ev of energy absorbed was used to

establish the sump contribution. Both of these hydrogen generation constants are those reported in the literature. The "G" value of 0.45 is used in the core region and is reported as a conservative upper limit for boiling solutions (Reference 2, Reference 3). The "G" value of 0.3 is used for the coolant in the sump which represents a slowly moving fluid and it is based upon published ORNL data (Reference 4).

15.16.2.2 Chemical Hydrogen Generation

In addition to the radiolytic hydrogen generation sources (core and sump radiolysis) following a Design Basis Accident, hydrogen may also be evolved from two chemical sources: (1) zirconium-water reaction involving clad material, and (2) from the reaction of zinc and aluminum within the Reactor Building with the borated coolant water.

15.16.2.2.1 Method of Analysis

The quantity of zirconium which reacts with the core cooling solution depends on the performance of the Emergency Core Cooling System. The 10CFR50.46 criteria for evaluation of the Emergency Core Cooling System requires that the zircalloy-water reaction be limited to one percent by weight of the total quantity in the core.

Aluminum is more reactive with the Reactor Building spray solution than other plant materials such as galvanized steel, copper, and copper-nickle alloys. However, because of the relatively large amount of exposed galvanized and zinc-based painted surfaces in the Reactor Building, zinc corrosion must be considered as a contributing hydrogen source.

It should be noted that zirconium-water reaction and the aluminum and zinc corrosion with Reactor Building spray are chemical reactions and thus essentially independent of the radiation field inside the Reactor Building following a LOCA. Radiolytic decomposition of water is dependent on the radiation field intensity. The radiation field inside the Reactor Building is calculated for the maximum credible accident in which the fission product activities given in TID-14844 are used.

15.16.2.2.2 Typical Assumptions

The following discussion outlines the assumptions used in the calculations.

15.16.2.2.3 Zirconium-water Reaction

Hydrogen can be generated during a LOCA by the reaction of hot zirconium cladding with the surrounding steam. The zirconium-water reaction is described by the chemical equation:

$$Zr + 2H_2O \text{ ------> } ZrO_2 + 2H_2 + \text{Heat}$$

The quantity of zirconium which reacts with the core cooling solution depends on the performance of the Emergency Core Cooling System (ECCS). The 10CFR50.46 criteria for evaluation of the ECCS requires that the zirconium-water reaction be limited to one percent by weight of the total quantity of zirconium in the core. For Oconee the maximum of 1% zirconium-water reaction is assumed. Regulatory Guide 1.7 requires that the assumption for hydrogen produced from the zirconium-water reaction equal 5 times the extent of the maximum calculated reaction under 10CFR50.46, i.e., 5.0%. Per Regulatory Guide 1.7, the zirconium-water hydrogen source is assumed to be released over a 2 minute period from the start of the transient, and is assumed to be distributed uniformly throughout Containment.

5 *15.16.2.2.3.1 Corrosion of Plant Materials*

5 Another possible source of hydrogen could occur from metal surfaces exposed to an environment
5 containing high-temperature steam, corrosive sprays, fission products, and radioactivity. Such exposure
5 might result in surface corrosion reactions that produce hydrogen. Corrosive tests have been performed to
5 determine the behavior of various metals that are used in Containment when exposed to a post-LOCA
5 environment. As applied to the quantitative definition of hydrogen production rates, the results of the
5 corrosion tests have shown that only aluminum will corrode at a rate that will significantly add to the
5 hydrogen accumulation in the Containment atmosphere. However, because of the relatively large amount
5 of exposed galvanized and zinc-based painted surfaces in Containment, zinc corrosion must be considered
5 as a contributing hydrogen source.

5 The corrosion of aluminum and zinc may be described by the following reactions:

5 $$2Al + 3H_2O \text{-----}> Al_2O_3 + 3H_2$$
5 $$Zn + H_20 \text{-----}> ZnO + H_2$$

5 The time-temperature cycle considered in the calculation of aluminum and zinc corrosion are based on a
5 conservative representation of the postulated post accident Containment transient. The corrosion data
5 points include the effects of temperature, alloy, and spray solution conditions. NOTE: In Section 5, Part
5 C of Regulatory Guide 1.7 it is stated that values given in Table 1 for evaluating production of
5 combustible gases following a LOCA may be changed on the basis of additional experimental evidence
5 and analyses. As a result the minimum assumed value give for aluminum corrosion rate of 200 mpy is
5 not used in the analysis.

5 **15.16.2.3 Primary Coolant Hydrogen**

5 The maximum equilibrium quantity of hydrogen in the primary coolant is 472 scf. This value includes
5 both hydrogen dissolved in the coolant water at 15-40 cc (STP) per liter of water and corresponding
5 equilibrium hydrogen in the pressurizer gas space. The 472 scf of hydrogen is assumed to be released
5 immediately into Containment at the initiation of the LOCA.

5 15.16.3 EVALUATION OF RECOMBINATION TO CONTROL HYDROGEN 5 CONCENTRATIONS

5 **15.16.3.1 Hydrogen Flammability Limits**

5 In order to determine the acceptability of any hydrogen removal system, the hydrogen concentration that
5 would constitute a potential hazard if that concentration were exceeded must be established. Regulatory
5 Guide 1.7 defines a concentration limit of 4 volume percent for hydrogen accumulation following a loss of
5 coolant accident.

5 The hydrogen generation which occurs following a design basis LOCA is a slow process driven by sump
5 radiolysis and metal corrosion. Calculations have shown that many days are required to reach the
5 regulatory limit of 4 volume percent. A hydrogen concentration slightly above 4 volume percent is
5 generally accepted as a lower flammability limit. Furthermore, assuming no credit for the Containment
5 Hydrogen Recombiner System, the concentration thirty days following a design basis LOCA is
7 approximately 6.9 volume percent. Studies of containment structural capacity and the effects of hydrogen
5 combustion have shown concentrations much higher than 4 volume percent are required to threaten the
5 integrity of a large dry containment like the Oconee containments. Concentrations in excess of 12 volume
5 percent would be required to present a challenge to the integrity of the Oconee containments.

Concentrations of this magnitude are only expected during core damage accidents like those studied in probabilistic risk analyses.

Although a concentration greater than 4 volume/percent may be acceptable, the lower flammability limit of 4 volume/percent specified by Regulatory Guide 1.7 is nevertheless used in this evaluation.

15.16.3.2 Evaluation of Recombination to Control Hydrogen Concentrations

Prediction of hydrogen generation following the loss-of-coolant accident using the assumptions and method of analysis described in Section 15.16.2, "Post-Accident Hydrogen Generation" shows that although hydrogen production rate decreases as the post-accident time increases, total hydrogen accumulation can exceed the lower flammability limit of 4 volume percent. The analysis shows that using conservative assumptions, post-LOCA hydrogen concentrations can reach 3 volume percent in approximately 168 hours (7 days) and 4 volume percent in approximately 310 hours (13 days). A method of control is therefore necessary to prevent hydrogen accumulation from exceeding the Regulatory Guide 1.7 limit of 4 volume percent.

Recombination of hydrogen and oxygen in the reactor building atmosphere is the chosen means of post-accident hydrogen control. The Containment Hydrogen Recombiner System (CHRS) is designed to operate at a flowrate of greater than 50 SCFM with concentrations of 0.5 volume percent and a recombination efficiency of 95%. Additionally, use of the recombiner will not increase offsite releases of radioactive material.

The basic approach evaluated herein is to allow the hydrogen concentration to increase for a minimum of 7 days prior to placing the CHRS into service. This allows time for pressures and temperatures to decrease in the Reactor Building prior to placing the system in service. With hydrogen concentrations conservatively calculated following Regulatory Guide 1.7 methodology not to reach 4 volume percent in containment for 310 hours after the initiation of the event, allowing this 7 day time would not cause the 4 limit to be exceeded. Steps are taken to place the recombiner in service when the hydrogen concentration exceeds 0.5 volume percent within the preceeding time limitations and within the pressure/temperature limitations of the recombiner system components. The analysis shows that when recombiner operation is begun as stated above at a flow rate of greater than 50 SCFM, safe hydrogen concentrations will be maintained in containment.

Post accident hydrogen concentrations are indicated by the Containment Hydrogen Monitoring System (CHMS). The CHMS is described in Section 9.3.7, "Containment Hydrogen Monitoring System" and is shown in Figure 9-15. This instrumentation provides two redundant channels of hydrogen monitoring that can monitor hydrogen concentrations at different levels of the containment including CHRS inlet and return concentrations. Should both trains of hydrogen monitoring be inoperable and no other means of hydrogen measurement be available, the CHRS will be placed in service after 7 days from initiation of the accident to assure hydrogen concentrations are not exceeded.

In order to assure high concentration pockets of hydrogen do not exist and that representative samples of hydrogen can be obtained, adequate mixing of hydrogen throughout containment should exist. Mixing in the Reactor Building atmosphere is expected to be good. The Reactor Building cooling fans or sprays will introduce considerable turbulence to the building atmosphere to provide good mixing of hydrogen in the early stages of the accident. In addition, all the Reactor Building volumes are connected by large vent areas (stair wells, elevator shafts, grating) to promote good air circulation.

Figure 15-89 shows the Reactor Building cross-section. The hydrogen generated will be primarily from the corrosion of aluminum HVAC equipment in the large open area of the containment and from radiolysis of water in the sump and water leaking from the RCS. These locations are within the

5 unrestricted main volume of the building and will permit the hydrogen to diffuse rapidly and provide a
5 uniform mixture in this area. This rapid mixing occurs because hydrogen has a high diffusion rate and a
5 low generation rate, and is capable of diffusing in all directions. The hydrogen will diffuse very rapidly
5 giving an even distribution under the conditions existing in the Reactor Building. This situation is not
5 analogous to one where attempts are made to mix streams of gases under dynamic conditions where
5 residence times and mixing distances are critical. In addition, the thermal mixing effects, heating of air
5 above the hot sump water, and possible steam releases from the RCS will move the hydrogen laden air
5 from the points of generation toward the cold external walls and emergency cooling equipment. Although
5 hydrogen is lighter than air, it will not tend to concentrate in high areas because of the high diffusion rate
5 and because of the open design of the Reactor Building.

5 Since the hydrogen is generated primarily from corrosion of aluminum and core radiolysis in the large
5 open areas, the hydrogen must diffuse from the major volumes into those minor volumes which are
5 enclosed. The minor volumes or those not having good communication with the major volumes would
5 be at a lower hydrogen concentration because the hydrogen is diffusing from the higher concentration
5 level to a lower concentration level. Accordingly, pockets, if they exist, will be low concentration pockets
5 rather than high concentration pockets. As the maximum concentration in the major volume will never
5 exceed the 4.0 volume/percent limit, flammable or explosive mixtures will not exist in the minor volumes
5 which might be considered as pocket areas.

5 The ability of hydrogen to diffuse rapidly into all volumes is inferred by a condensing steam
5 environment (CSE) experiment (Reference 8) which measured the spatial concentration of iodine in the
5 various compartments. The tests showed very good mixing in the main chamber and a rapid interchange
5 by diffusion and mixing with the atmosphere of other chambers which had limited communication. The
5 diffusivity of hydrogen is approximately 10 times that of iodine so a more uniform mixture would be
5 expected for hydrogen than for iodine. Also, the higher concentrations would provide greater
5 concentration gradients for better diffusion than was indicated by the CSE tests.

5 During a DBA LOCA, the operation of Reactor Building sprays and RBCUs will provide mixing in
5 containment. This along with the fact that the hydrogen generation rates are low for the majority of the
5 accident support the conclusion that a nearly uniform hydrogen concentration will exist in containment.
5 Even though the average hydrogen concentration throughout containment may be less than 4 v/0, some
5 small pockets of hydrogen exceeding 4 v/o by a small amount would not be detrimental. Results of
5 experiments summarized in Regulatory Guide 1.7 state that for hydrogen concentrations in the rage of 4
5 to 6 volume percent, partial burning of the hydrogen above 4 percent may occur. However, in this range
5 of 4 to 6 percent, the rate of flame propagation is less than the rate of rise of the flammable mixture.
5 Therefore, whether uniform mixing exists or not, hydrogen concentration at 4 volume percent or slightly
5 higher are not a concern.

5 15.16.4 CONTAINMENT HYDROGEN RECOMBINER SYSTEM DESCRIPTION

5 The Containment Hydrogen Recombiner System consists of a portable hydrogen recombiner, control
5 panel for the recombiner, and piping. The Oconee recombiners are Thermal Hydrogen Recombiners
5 developed and constructed by Rockwell International. Two recombiners are normally maintained at the
8 Oconee site. Only one recombiner is required operable per Oconee SLC 16.6.10, "Containment Hydrogen
8 Recombiner System". Duke Power Company maintains a lease agreement with Carolina Power and
5 Light (CP&L) and Florida Power and Light (FP&L) for use of the second recombiner when needed at
5 the H.B. Robinson Nuclear Site for CP&L and the Turkey Point Nuclear Site for FP&L. This
5 agreement is based on the sharing of recombiners between sites as described in Regulatory Guide 1.7.

5 The recombiner is normally not connected to a containment building. When needed post-LOCA, the
5 recombiner and control cabinet will be moved to the affected unit. The control cabinet will be installed

on a pad near the recombiner. The recombiner will be anchored to its foundation, and connected by flexible piping to the piping which runs to and from containment penetrations 60 and 61.

The hydrogen recombiner controls hydrogen by recombining hydrogen with oxygen to form water vapor, which is returned to the reactor building. The air is heated by radiant heaters to a temperature high enough (approximately 1200°F) to begin recombination of the hydrogen and oxygen to form water vapor. Recombination of hydrogen and oxygen is an exothermic reaction and the recombiner is designed to use the heat generated by the reaction to aid in maintaining the process. As temperature increases due to heat generated, controls automatically reduce heater output to maintain proper reaction chamber temperature of approximately 1340°F. The recombiner is capable of processing 90 SCFM with a recombination efficiency of at least 95% for hydrogen concentrations greater than 0.5 volume percent. Although the design flowrate for the recombiner is 90 SCFM, the operating flow rate at Oconee is less since there are several hundred feet of supply and return piping. The minimum required flow rate for post-accident operation is 50 SCFM. The Hydrogen Recombiners are located in a mild environment and are therefore not within the scope of 10CFR50.49. Major component data is listed in Table 15-25.

Any condensation that may accumulate in the CHRS supply and return piping will be routed by a gravity drainage system to the Reactor Building Normal Sump.

The recombiner is the preferred method of hydrogen control since there is no release of radioactive material to the atmosphere. The air/hydrogen mixture is drawn from the reactor building and the air and water vapor mixture is returned to the Reactor Building.

The supply flow path for recombiner operation is from the Reactor Building via Inboard Containment Isolation Valve 1(2)(3)PR-7, Penetration 60, Outboard Containment Isolation Valve 1(2)(3)PR-8, and flexible coupling PR FX0001 & 0002 to the recombiner unit. The flow path through the recombiner is the blower, the flow element, the radiant heaters, the reaction chamber, and the air blast heat exchanger.

The air blast heat exchanger is cooled by the air blast blower, which forces approximately 3000 CFM of air at ambient temperature through the heat exchanger to cool the air/water vapor mixture to near ambient temperature before returning to the Reactor Building. The recombiner will automatically shutdown if outlet temperature reaches 146°F.

The return flow path is via flexible coupling PR FX0005 and PR FX0006, manual valve 1(2)(3)PR-61, Outboard Containment Isolation Valve 1(2)(3)PR-10, Penetration 61, and Inboard Containment Isolation Valve 1(2)(3)PR-9.

Electric motor operated valves 1(2)(3)PR-7 and 1(2)(3)PR-9 close on an Engineered Safeguards Channel 1 signal. Air operated valves 1(2)(3)PR-8 and 1(2)(3)PR-10 close on an Engineered Safeguards Channel 2 signal. These are redundant channels which actuate on low RC pressure or high RB pressure to close these containment penetration isolation valves.

An alternate supply flow path is provided by Hydrogen Recombiner Inlet Containment Isolation Valve 1(2)(3)PR-59 and an alternate return flow path is provided by Hydrogen Recombiner Return Containment Isolation Valve 1(2)(3)PR-60. These valves are normally closed EOVs, capable of being operated electrically from the cable rooms. The valves are installed to ensure a failure of 1(2)(3)PR-7 or 1(2)(3)PR-9 would not prevent operation of the CHRS. Power is supplied to these valve from non-safety related, non-load shed power. The flow configuration of the CHRS is shown on Figure 15-110.

Manual action is relied upon outside of containment to restore failed valves or other components that may fail to operate post-LOCA. Sufficient time is available to correct any problems that may occur.

All piping and equipment necessary for the function of the CHRS are designed to withstand a Safe Shutdown Earthquake without a loss of function except CHRS power. Power for the Containment Hydrogen Recombiner is normally supplied from non-safety power via the Auxiliary Power Upgrade Busses. In the event power is not available from the normal supply, power can be manually restored from either of two non-safety, non-loadshed power supplies.

Detailed design information is provided in Reference 13.

15.16.5 CONTAINMENT HYDROGEN RECOMBINER SYSTEM OPERATION AND TESTING

Following a LOCA, the process of placing the CHRS in service is begun when the containment hydrogen concentration in containment reaches 0.5% by volume. The recombiner and control cabinet are placed on the appropriate pads of the affected Unit. Electrical and mechanical connections are made to connect the recombiner to the affected Unit. Mechanical connections are leak rate tested and valve alignments are made to align the CHRS for operation. After 7 days, when system operating parameters are within allowable limits, the recombiner is placed in service.

Testing of the recombiner and flow path is performed every 18 months. This testing includes:

- Visual inspection of the CHR Unit
- Calibration of all recombiner instrumentation and control circuits
- Operation of the CHRS in the post-LOCA configuration
- Verifying proper operation of heaters and controls
- Verifying acceptable flowrates through the recombiner
- Verifying acceptable flowrates through the hydrogen recombiner flowpath
- Leak rate testing of the recombiner and piping
- Leak rate testing of the blind isolation flanges on the CHRS permanent piping (tested after each installation)

15.16.6 CONCLUSIONS

The analyses also show that the hydrogen generated in the Reactor Building following a LOCA can be adequately controlled using the CHRS with a flowrate of greater than 50 SCFM (Figure 15-87). The peak hydrogen concentration of 3.97 v/o does not occur until 30 days post-LOCA.

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15.17 SMALL STEAM LINE BREAK ACCIDENT

15.17.1 IDENTIFICATION OF CAUSES AND DESCRIPTION

The small steam line break accident is caused by small breaks in the steam lines or by failures of valves connected to the steam lines. The break flowrate, the reactor kinetic behavior, and the status of the control systems have a large effect on the plant response. The initial plant response to the increase in steam flow is a decrease in steam generator pressure and an overcooling of the Reactor Coolant System (RCS). The expected plant response with the Integrated Control System (ICS) in automatic would be for the main turbine control valves to close to return turbine header pressure to the setpoint, the control rods would insert to offset the increase in the reactor power due to the negative moderator coefficient of reactivity, and main feedwater (MFW) flow would be controlled to maintain the secondary heat sink in balance with the reactor power. This automatic response may be successful in not tripping the reactor. With the ICS in automatic or manual control, a reactor trip on high neutron flux, flux/flow/imbalance, variable low pressure-temperature, on turbine trip due to main feedwater pump trip, or by manual operator action would be expected.

The small steam line break accident analyses assume that the ICS is in manual control for initial conditions of full power with four reactor coolant pumps (RCPs) in operation, and 80% power with three RCPs in operation. The ICS in manual control is more limiting than with the ICS in automatic. A range of break sizes and moderator temperature coefficients are analyzed to determine the combination that approaches the most limiting conditions relative to the DNBR limit. The effect of a decrease in the reactor vessel downcomer temperature on the indicated excore power range flux is modeled. Several non-safety systems could cause a trip of the MFW pumps thereby mitigating the consequences of the transient. These include the steam line break mitigation circuitry (which actuates some non-safety grade components), the ICS high steam generator level trip, and the low MFW pump discharge pressure trip. None of these non-safety systems are credited in the analyses. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Operator action is credited with manually tripping the reactor at 10 minutes if an automatic reactor trip has not occurred. No single failure has been identified which adversely affects this transient.

A small steam line break accident is considered to be either a fault of moderate frequency (valves failing open) or an infrequent fault (pipe break). To bound both types of events, the analysis assumes pipe breaks as initiating events, with acceptance criteria corresponding to the less severe fault of moderate frequency category. The acceptance criteria for this accident are that the minimum DNBR remains above the limit (1.50 for four RCP operation and 1.53 for three RCP operation), that the centerline fuel melt limit is not exceeded, and that the offsite doses will be within 10% of the 10CFR100 limits.

15.17.2 ANALYSIS

The limiting small steam line break accident for DNB considerations is a break size of 1.2 ft^2 initiated from three RCP operation, with a moderator temperature coefficient of -12 pcm/°F. The transient response is given in Figure 15-168, Figure 15-169, Figure 15-170, Figure 15-171, Figure 15-172 and Figure 15-173 and the sequence of events is given in Table 15-49. The duration of the analysis is 250 seconds, which includes the core conditions of minimum DNBR margin. The blowdown out the break increases the steam flow exiting the steam generators by approximately 30% (Figure 15-168). The steam

generator pressure decrease (Figure 15-169) propagates throughout the secondary system, causing main feedwater flow to increase (Figure 15-170) and a decrease in main feedwater temperature. RCS temperatures decrease (Figure 15-171) causing a power increase (Figure 15-172) due to the negative moderator temperature coefficient of reactivity. As the power level increases, the temperature increases and the moderator and Doppler feedback mitigates the power excursion. The transient reaches a sustained power level of approximately 113%. The high flux and the flux/flow/imbalance trips do not actuate due to the effect of the decrease in the reactor vessel downcomer temperature. The RCS pressure response (Figure 15-173) follows RCS average temperature. The system analysis results are input to a detailed core thermal-hydraulic analysis assuming a standard reference power distribution. The minimum DNBR of 1.301 is less than the design limit of 1.53. Consequently, DNBR margin may not exist, and a fuel pin census analysis is performed to determine if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. A range of pin radial peaks and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel rod in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the fuel rod exceeds the DNBR limit. All fuel rods that exceed the DNBR limit are assumed to experience cladding failure and are counted in the source term for the offsite dose calculation. The results of the fuel pin census analysis for the small steam line break accident is that DNB margin exists for all of the fuel pins. The centerline fuel melt limit has been evaluated and it is not violated.

15.17.3 ENVIRONMENTAL CONSEQUENCES

A conservative consequences analysis is performed for the postulated small steam line break outside containment. The transient cool-down of the Reactor Coolant System (RCS) and the associated positive reactivity addition to the core do not lead to accident-induced fuel failures or breaches of the primary system pressure boundary. Therefore, environmental consequences can only arise from atmospheric releases of pre-existing RCS activity via primary-to-secondary leakage and of contaminated secondary system coolant.

Two postulated cases are analyzed:

Case 1: Equilibrium RCS iodine specific concentrations, at the technical specification limit, exist at the time of the accident. The primary activities for non-iodine isotopes bound the limits set by Technical Specifications. No iodine release rate spiking is assumed.

Case 2: Pre-existing iodine spike at the time the accident occurs. The reactor coolant concentrations are the maximum permitted for full power operation (50 times the normal equilibrium Technical Specification limit).

The secondary side coolant activity prior to the accident corresponds to limits set by Technical Specifications.

The initial conditions, boundary conditions and assumptions of the analysis are chosen to maximize the release of radionuclides to the environment by maximizing the stored energy in the primary system, the primary to secondary leakage, and the secondary-side pressurization. The following assumptions and parameters are used to calculate the activity release and offsite dose for the postulated small MLSB accident:

1. The reactor is assumed to be at the end of a 500 EFPD cycle with extended operation at 102% full power (2619.4 MWt).
2. No core cladding ruptures or fuel melting occur during the accident.
3. Offsite power is maintained for the duration of the accident.

4. A pre-existing, 1 gpm primary-to-secondary leakage is assumed to be located in the affected steam generator. This leakage is assumed to vary as the plant is cooled to cold shutdown (Mode 5). The associated activity releases to the environment bound those corresponding to primary-to-secondary leakage at the technical specification limits.
5. During the accident, credit is taken for depletion of the RCS fission product activities by radioactive decay and by primary-to-secondary leakage.
6. All noble gases contained in the RCS coolant leaking to the OTSG secondary side are immediately released to the atmosphere, with no retention in the secondary coolant.
7. The following iodine partition coefficients are assumed:
   - **a)** The steam generator steam/water interface iodine partition coefficient is 1.
   - **b)** The partition coefficient for main steam/auxiliary steam providing the motive force in the condenser steam air ejectors (CSAEs) is 1.
   - **c)** The condenser partition coefficient is 10,000 for iodine entering the condenser and then exiting via the CSAEs to the unit vent.
8. No credit is taken for either heat removal or iodine retention in the condenser once the turbine stop valves close. Instead, the atmospheric dump valve associated with the unruptured main steam line is used to cool the plant to cold shutdown (Mode 5).
9. Beginning at 70 minutes, the plant is cooled to cold shutdown (Mode 5) at a rate within the technical specification limits that leads to conservative offsite doses.
10. SG steaming to atmosphere ends at 2.9 hours with primary to secondary releases ending at 3.9 hours.
11. The RCS is assumed to be cooled to cold shutdown conditions at the Tech Spec maximum permissible rates.
12. No credit is taken for plate-out of iodine in the steam generator steam lines.
13. The primary coolant releases from the ruptured steam generator terminates once the RCS has been cooled to cold shutdown (Mode 5) conditions and the RCS pressure is less than or equal to the pressure in the secondary-side of the OTSGs.
14. Other parameters are listed in Table 15-55.

Prior to a manual reactor trip at 10 minutes, the RCS depressurizes and begins cooldown leading to positive reactivity and increase in core power. Following manual reactor trip one MDEFWP starts and motive steam flow to TDEFWP is initiated. The operators stabilize plant and hold plant at the thermal shock operating region for 1 hour and begin a controlled cooldown at 70 minutes.

Based on the foregoing model, the primary and secondary side releases may be calculated, as well as the offsite doses. The doses are below the regulatory acceptance criteria of a small fraction of 10 CFR 100 limits, for each of the above cases analyzed. The results are presented in Table 15-55.

15.17.4 CONCLUSIONS

The small steam line break accident analysis results show that DNBR margin exists for all of the fuel rods, and that no fuel failures due to centerline fuel melt occur. The environmental consequences meet the acceptance criteria. All of the acceptance criteria are met.

THIS IS THE LAST PAGE OF THE CHAPTER 15 TEXT PORTION.

Table 15-2. Rod Ejection Accident SIMULATE-3K Analysis Results

Parameter	BOC 4 RCP	BOC 3 RCP	BOC HZP	EOC 4 RCP	EOC 3 RCP	EOC HZP
Initial rod position (%wd)	58	38	0	58	38	0
Ejected rod worth (pcm)	200	400	800	200	400	800
Delay neutron fraction	0.0058	0.0058	0.0058	0.0049	0.0049	0.0049
Begin rod ejection (sec)	0	0	0	0	0	0
End rod ejection (sec)	0.063	0.093	0.150	0.063	0.093	0.150
Maximium neutron power (%FP)	140	194	1841	137	214	1752
Time of maximum power (sec)	0.076	0.109	0.228	0.081	0.117	0.277
Peak assembly power	2.29	2.93	4.17	2.25	3.00	4.33
Peak nodal power	3.14	4.20	6.40	3.09	4.81	10.5
High flux trip time (sec)	0.054	0.082	0.248	0.057	0.083	0.245
Begin scram rod motion (sec)	0.454	0.482	0.648	0.457	0.483	0.645
End scram rod motion (sec)	2.854	2.882	3.048	2.857	2.883	3.045

Table 15-3. Rod Ejection Accident ARROTTA Analysis Results

Parameter	BOC 4 RCP	BOC 3 RCP	BOC HZP	EOC 4 RCP	EOC 3 RCP	EOC HZP
Initial rod position (%wd)	58	38	0	58	38	0
Ejected rod worth (pcm)	200	400	800	200	400	800
Delay neutron fraction	0.0058	0.0058	0.0058	0.0049	0.0049	0.0049
Begin rod ejection (sec)	0	0	0	0	0	0
End rod ejection (sec)	0.063	0.093	0.150	0.063	0.093	0.150
Maximium neutron power (%FP)	144	195	2098	148	223	1918
Time of maximum power (sec)	0.076	0.106	0.270	0.079	0.112	0.262
Peak assembly power	2.38	3.01	4.28	2.45	3.12	4.51
Peak nodal power	3.33	4.37	6.66	3.44	4.77	9.99
High flux trip time (sec)	0.054	0.082	0.248	0.057	0.083	0.245
Begin scram rod motion (sec)	0.454	0.482	0.648	0.457	0.483	0.645
End scram rod motion (sec)	2.854	2.882	3.048	2.857	2.883	3.045
Peak pellet average enthalpy (cal/gm)	132.8	129.0	55.1	109.7	118.3	58.5
Percent pins exceeding DNBR (%)	40.6	39.2	< 1	27.6	36.3	2.1

9 **Table 15-5. Steam Line Break Accident - With Offsite Power Case Sequence of Events**

9 Event	Time (sec)
9 Break opens	0.0
9 Reactor trip on variable low pressure-temperature	0.7
9 Control rod insertion begins	0.8
9 Third CBP starts	1.5
9 Turbine stop valves closed 9 Control rods fully inserted	1.8
9 MSSV opens on unaffected SG	6.9
9 HPI actuates	20.8
9 MSSV closes on unaffected SG	26.9
9 Boron injection from HPI begins	103.4
9 CFT injection begins	131.5
9 Boron from CFT B starts	152.0
9 Boron from CFT A starts	157.2
9 Peak return-to-power occurs	160.0
9 End of simulation	600.0

9

7 **Table 15-6. Summary of LOCA Break Spectrum Break Size and Type**

Parameter	CLPD DE	CLPD DE	CLPD DE	CLPD Split	CLPS DE
Break C_D	1.0	0.8	0.6	1.0	1.0
Unruptured node	12	12	13	13	12
PCT, °F	1915.1	1895.9	1851.9	1811.5	1829.9
Time, sec	33.549	41.515	37.100	34.086	32.151
Local oxidation, %	1.7364	1.5650	1.0324	0.9773	1.0277
Ruptured node	11	13	12	12	13
PCT, °F	1957.1	1889.6	1820.9	1745.0	1796.3
Time, sec	28.604	29.845	31.511	31.055	32.284
Local oxidation, %	2.0190	1.8633	1.6000	1.4752	1.5446
Clad rupture time, sec	19.02	20.655	23.21	21.02	19.19
CFTs begin injection, sec	11.80	12.80	14.60	12.20	13.00
End of bypass, sec*	18.14	19.29	21.56	18.90	17.70
End of blowdown, sec	20.16	21.46	24.20	21.01	22.94
End of adiabatic heatup, sec	26.562	27.721	29.988	27.475	25.542
Water mass in reactor vessel lower plenum at end of blowdown, lbm	16701.6	17695.6	20418.6	16811.3	36238.7

Table 15-16. Summary of Transient and Accident Doses Including the Effects of High Burnup Reload Cores

	Doses (rem)	
Fuel Handling Accident		
Thyroid at EAB	5.25E+1	
Whole body at EAB	1.85E-1	
Steam Generator Tube Rupture	Case 1	Case 2
Thyroid at EAB	3.95E+1	2.62E+2
Whole body at EAB	7.36E-2	4.39E-1
Thyroid at LPZ	1.13E+1	6.61E+1
Whole body at LPZ	1.52E-2	7.65E-2
Waste Gas Tank Failure		
Whole body at EAB	4.4E-1	
Rod Ejection		
Thyroid at EAB	1.04E+2	
Whole body at EAB	4.97E-1	
Thyroid at LPZ	2.25E+1	
Whole body at LPZ	7.75E-2	
Large Main Steam Line Break		
Thyroid at EAB	9.80E+0	1.14E+1
Whole body at EAB	2.39E-3	1.50E-2
Thyroid at LPZ	1.33E+0	1.92E+0
Whole body at LPZ	4.62E-4	4.07E-3
Small Main Steam Line Break		
Thyroid at EAB	4.97E+0	6.69E+0
Whole body at EAB	2.32E-3	1.53E-2
Thyroid at LPZ	8.70E-1	1.52E+0
Whole body at LPZ	7.07E-4	4.33E-3
LOCA		
Thyroid at EAB	5.00E+0	
Whole body at EAB	1.00E-2	
Thyroid at LPZ	5.50E+0	
Whole body at LPZ	1.40E-2	
Maximum Hypothetical Accident		
Thyroid at EAB	283E+2	
Whole body at EAB	1.91E+0	
Thyroid at LPZ	2.15E+2	
Whole body at LPZ	5.32E-1	
Fuel shipping cask drop accident*		
Thyroid at EAB	1.42E+2	
Whole body at EAB	1.30E-1	
Dry storage transfer cask drop*		
Thyroid at EAB	7.20E+1	
Whole body at EAB	1.50E-1	

Note: * Not reanalyzed for high burnup fuel, although the impact is negligible.

Table 15-32 (Page 1 of 2). Summary of Transient and Accident Cases Analyzed

UFSAR Section	Description of Transient	Summary of Cases Analyzed
15.2	Startup Accident	Peak RCS pressure
15.3	Rod Withdrawal at Power	1. Core cooling capability 2. Peak RCS pressure
15.4	Moderator Dilution Accidents	1. Power operation 2. Refueling
15.5	Cold Water Accident	Core cooling capability
15.6	Loss of Coolant Flow	Core cooling capability: 1. Four RCP trip from four-RCPs 2. Two RCP trip from four-RCPs 3. One RCP trip from three-RCPs 4. Locked rotor from four-RCPs 5. Locked rotor from three-RCPs
15.7	Control Rod Misalignment Accidents	Core cooling capability 1. Dropped rod from four-pumps 2. Dropped rod from three-pumps 3. Statically misaligned rod
15.8	Turbine Trip	Peak RCS pressure
15.9	Steam Generator Tube Rupture	Offsite dose
15.10	Waste Gas Tank Rupture	Offsite dose
15.11	Fuel Handling Accidents	Offsite dose 1. Fuel handling accident in Spent Fuel Pool 2. Fuel handling accident in containment 3. Fuel shipping cask drop 4. Dry storage canister cask drop
15.12	Rod Ejection	Peak fuel enthalpy 1/2.Four-pump BOC and EOC 3/4.Three-pump BOC and EOC 5/6.Three-pump BOC and EOC, HZP Core cooling capability 1/2.Four-pump BOC and EOC 3/4.Three-pump BOC and EOC 5/6.Three-pump BOC and EOC, HZP Peak RCS pressure 7.Three-pump BOC

9 **Table 15-32 (Page 2 of 2). Summary of Transient and Accident Cases Analyzed**

9 9 UFSAR Section	Description of Transient	Summary of Cases Analyzed
9 15.13	Steam Line Break	Core cooling capability
9		1. With offsite power
9		2. Without offsite power
9 15.14	Loss of Coolant Accidents	10CFR50.46 and offsite dose
9		1. Large-break LOCA spectrum
9		Mk-B9 fuel LOCA limit cases
9		Mk-B10 fuel LOCA limit cases
9		2. Small-break LOCA spectrum
9 15.15	Maximum Hypothetical Accident	Large Break LOCA - offsite dose
9 15.16	Post-Accident Hydrogen Control	Large Break LOCA - flammability limit
9 15.17	Small Steam Line Break	Core cooling capability

Table 15-33. Methodology Topical Reports and Computer Codes Used in Analyses

	UFSAR Section	Topical Reports	Computer Codes
15.2	Startup Accident	DPC-NE-3005-PA	RETRAN-02 SIMULATE-3P
15.3	Rod Withdrawal at Power Accident	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P
15.4	Moderator Dilution Accidents	DPC-NE-3005-PA	N/A
15.5	Cold Water Accident	DPC-NE-3005-PA	RETRAN-02
15.6	Loss of Coolant Flow Accidents	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P
15.7	Control Rod Misalignment Accidents	DPC-NE-3005-PA	RETRAIN-02 VIPRE-01 SIMULATE-3P
15.8	Turbine Trip Accident	DPC-NE-3005-PA	RETRAN-02
15.9	Steam Generator Tube Rupture Accident	DPC-NE-3005-PA	RETRAN-02
15.12	Rod Ejection Accident	DPC-NE-3005-PA	SIMULATE-3K SIMULATE-3P ARROTTA RETRAN-02 VIPRE-01
15.13	Steam Line Break Accident	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P
15.14	Loss of Coolant Accident		
	Large Breaks	BAW-10192-P	RELAP5/MOD2-B&W CONTEMPT REFLOD3 BEACH
	Small Breaks	BAW-10154-P	CRAFT2 FOAM2 THETA-1B
15.17	Small Steam Line Break Accident	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P

Table 15-34 (Page 1 of 5). Summary of Input Parameters for Accident Analyses Using Computer Codes

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
15.2	N/A	1.0E-7	532	2155	272,976	285	+7.0E-5	Note 2	0.0065	15
15.3	1	100	579	2155	378,400	195	-3.0E-5	Note 2	0.0065	1
	2	102	581	2185	371,360	285	3.0E-5	Note 2	0.0065	15
15.5	N/A	80	579	2125	282,665	195	-35.0E-5	Note 3	0.0049	1
15.6	1	100	579	2125	378,400	195	-3.00E-5	Note 2	0.0065	1
	2	100	579	2125	378,400	195	-3.00E-5	Note 2	0.0065	1
	3	80	579	2125	282,665	195	-2.2235E-5	Note 2	0.0065	1
	4	100	579	2125	378,400	195	-3.0E-5	Note 2	0.0065	1
	5	80	579	2125	282,665	195	-2.2235E-5	Note 2	0.0065	1
15.7	1	100	579	2125	378,400	195	-3.0E-5	Note2	0.0065	1
	2	80	579	2125	282,665	195	-3.0E-5	Note 2	0.0065	1
15.8	N/A	102	581	2185	371,360	285	-3.075E-5	Note 2	0.0065	15
15.9	N/A	102	577	2185	371,360	245	-35.0E-5	Note 4	0.0049	15
15.12	1	102	581	2095	371,360	N/A	-3.0E-5 Note 7	-1.25E-5	0.0058	N/A
	2	82	581	2095	272,985	N/A	-2.2E-5	-1.30E-5	0.0058	N/A
	3	10E-9	540	2095	173,448	N/A	+7.0E-5	-1.65E-5	0.0058	N/A
	4	102	581	2095	371,360	N/A	-25.0E-5	-1.35E-5	0.0049	N/A
	5	82	581	2095	272,985	N/A	-25.0E-5	-1.38E-5	0.0049	N/A
	6	10E-9	540	2095	173,448	N/A	-15.0E-5	-1.75E-5	0.0049	N/A
	7	82	581	2095	272,985	245	0.0	0.0	N/A	15

Table 15-34 (Page 2 of 5). Summary of Input Parameters for Accident Analyses Using Computer Codes

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
15.13	1	102	577	2095	371,360	195	Note 8	Note 5	0.0049	1
	2	100	579	2125	378,400	245	Note 9	Note 6	0.0065	1
15.14	1	102	580.5	2190	355,232 Note 1	220	0.0	Note 4	0.007	20
	2	110.3	581.9	2116.6	371,360 Note 10	260	0.0	-1.3896E-5	0.0071	0
15.17	N/A	80	579	2155	282,665	245	-12.0E-5	Note 3	0.0054	1

Note 1: LB LOCA analysis assumed 131.9 Mlb/hr or 100.9% of design flow.

Note 2: Doppler reactivity assumption as function of average fuel temperature:

Accident Analyses: 15.2, 15.3, 15.6, 15.7, 15.8

Average Fuel Temperature (°F)	Doppler Coefficient Δk/k-°F (x10^{-5})
231.4	-2.129
449.65	-1.7959
727.61	-1.4773
1424.01	-1.1856

Note 3: Doppler Reactivity assumption as function of average fuel temperature:

Accident Analyses: 15.5, 15.17

Average Fuel Temperature (°F)	Doppler Coefficient Δk/k-°F (x10^{-5})
457.73	-1.9084
629.14	-1.6884
889.38	-1.4683
1346.34	-1.3447

Note 4: Doppler reactivity assumption as function of average fuel temperature:

Accident Analyses: 15.9, 15.14 Case 1

Table 15-34 (Page 3 of 5). Summary of Input Parameters for Accident Analyses Using Computer Codes

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)

Average Fuel Temperature (°F)	Doppler Coefficient Δk/k-°F (x10^{-5})
452.38	-2.1782
754.3	-1.8795
1149.79	-1.6651
1350	-1.5566

Note 5: Doppler reactivity assumption as function of average fuel temperature:

Accident Analysis: 15.13 Case 1

Average Fuel Temperature (°F)	Doppler Reactivity %Δk/k
953.8	0
940.55	0.0221
920.55	0.0531
900.55	0.0854
532	0.9144
512	0.9556
500	0.979
450	1.0821
400	1.187
350	1.2948
300	1.4059
250	1.5205
200	1.639

Note 6: Doppler reactivity assumption as function of average fuel temperature:

Accident Analysis: 15.13 Case 2

Table 15-34 (Page 4 of 5). Summary of Input Parameters for Accident Analyses Using Computer Codes

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)

Average Fuel Temperature (°F)	Doppler Reactivity %Δk/k
1250	0
1200	0.0533
1150	0.1073
1112	0.1493
1052	0.2158
1000	0.2736
900	0.3898
800	0.509
700	0.6326
600	0.7611
532	1.0265

Note 7: Actual physics parameters values determine from code cross section library for 15.12 Cases 1-6, target values listed for moderator and doppler reactivities and β-effective.

Note 8: Moderator reactivity assumption as a function of moderator density.

Accident Analysis: 15.13 Case 1

Moderator Density (lbm/ft^3)	Moderator Reactivity %Δk/k
44.6805	0
45.2685	0.2294
46.0051	0.5095
46.6294	0.7376
47.6658	1.101
47.8133	1.6696
49.1185	2.2695
49.5917	2.4735
51.5476	3.283
52.0171	3.4673
53.7633	4.124
54.1503	4.2632
55.7105	4.8038
56.0313	4.9109
57.6164	5.4401
59.1166	5.9409

Table 15-34 (Page 5 of 5). Summary of Input Parameters for Accident Analyses Using Computer Codes

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)

Note 9: Moderator reactivity assumption as a function of moderator density.

Accident Analysis: 15.13 Case 2

Moderator Density (lbm/ft^3)	Moderator Reactivity %Δk/k
41.767	-0.06
42.941	-0.0214
43.828	-0.0048
44.296	0
44.538	0.003
45.363	-0.0042
46.1	-0.0177
46.724	-0.0351
47.813	-0.0626

Note 10: SB LOCA analysis assumed 137.9 Mlb/hr or 105.5% of design flow.

Table 15-35. Trip Setpoints and Time Delays Assumed in Accident Analyses

Trip Functions	Nominal Setpoint	Limiting Trip Setpoint Assumed in Analyses	Time Delay (seconds)
RPS:			
High Flux	105.5% FP	106.5% FP	0.4
High Pressure	2355 psig	2362 psig	0.5
Low Pressure	1800 psig	1793 psig (Note 2)	0.5
Variable Low Pressure-Temperature	Trip if: (Note 1) $P < 11.14 \cdot T_{hot}-4706$	Trip if: (Note 1) $P < 11.14 \cdot T_{hot}-4716$	0.7
High Temperature	618°F	618.85°F	0.7
Flux/Flow	Trip if: (Note 3) $\Phi > 109.4\%FP/flow \cdot Fm$	Trip if: (Note 3) $\Phi > 109.4\%FP/flow \cdot Fm + 2.2\%FP$	1.2
Pump Monitor		NA	0.6
ESPS:			
HPI	1590 psig	1480 psig 1400 psig (Note 6)	15 (no-LOOP) 38 (LOOP)
CFT	2 psid	+6.5 psid (CFT-A) -2.5 psid (CFT B) (Note 4)	NA
LPI		N/A (Note 5)	39 + 14 sec ramp

Notes:

1. "P" is gauge pressure.
2. SBLOCA analyses assume 1900 psig.
3. "Fm" is measured flow.
4. SBLOCA analyses assume 600 psig Nitrogen Pressure.
5. Trip setpoint not explicitly assumed, initiation on time delay with LBLOCA.
6. Large steam line break assumes HPI actuation at 1400 psig because of degraded containment conditions.

8 **Table 15-36. Startup Accident Sequence of Events**

8 Event	Time(sec)
Rod withdrawal begins	0.0
Pressurizer control heaters de-energize	49.5
High RCS pressure reactor trip	51.3
Control rod insertion begins	51.8
Pressurizer safety valves open	53.6
Peak RCS pressure occurs	54.3
Pressurizer safety valves reseat	56.6
End of simulation	100.0

9 **Table 15-37. Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis Sequence of Events**

Event	Time (sec)
Rod withdrawal begins	0.0
High RCS pressure reactor trip setpoint reached	38.7
Control rod insertion begins	39.2
Turbine trip on reactor trip	39.2
Main steam safety valves lift	41.9 - 43.3
Peak RCS pressure occurs	42.6
Main steam safety valves begin to reseat	44.5
End of simulation	49.2

9 **Table 15-38. Rod Withdrawal at Power Accident - Core Cooling Capability Analysis Sequence of Events**

Event	Time (sec)
Rod withdrawal begins	0.0
Pressurizer spray actuates	54.1
High pressure reactor trip setpoint reached	147.1
Control rod insertion begins	147.6
Turbine trip on reactor trip	147.6
Main steam safety valves lift	152 - 153
Pressurizer spray terminates	154.5
End of simulation	157.6

9 **Table 15-39. Cold Water Accident Sequence of Events**

Event	Time (sec)
Fourth RCP starts	0.1
RCP reaches full speed	4.1
Maximum heat flux occurs (96.7%FP)	6.0
End of simulation	15.0

Table 15-40. Loss of Flow Accidents Four RCP Coastdown from Four RCP Initial Conditions Sequence of Events

Event	Time (sec)
All RCPs trip	0.0
Pump monitor reactor trip	0.01
Rod motion begins	0.61
Turbine trip on reactor trip	0.77
Pressurizer spray initiates	2.90
MSSVs lift	3.43 - 4.36
End of simulation	19.0

Table 15-41. Loss of Flow Accidents Two RCP Coastdown from Four RCP Initial Conditions Sequence of Events

Event	Time (sec)
Two RCPs trip	0.0
Flux/flow reactor trip setpoint reached	3.51
Rod motion begins	4.71
Turbine trip on reactor trip	4.87
Pressurizer spray initiates	5.99
MSSVs lift	7.15 - 10.32
End of simulation	19.0

Table 15-42. Loss of Flow Accidents One RCP Coastdown from Three RCP Initial Conditions Sequence of Events

Event	Time (sec)
One RCPs trip	0.0
Flux/flow reactor trip setpoint reached	3.05
Rod motion begins	4.25
Turbine trip on reactor trip	4.41
MSSVs lift	6.56 - 8.93
End of simulation	19.0

9 **Table 15-43. Loss of Flow Accidents Locked Rotor from Four RCP Initial Conditions Sequence of Events**

Event	Time (sec)
Locked rotor occurs	0.0
Flux/flow reactor trip setpoint reached	0.51
Rod motion begins	1.71
Turbine trip on reactor trip	1.87
Pressurizer spray initiates	3.01
MSSVs lift	4.18 - 7.05
End of simulation	9.0

9 **Table 15-44. Loss of Flow Accidents Locked Rotor from Three RCP Initial Conditions Sequence of Events**

Event	Time (sec)
Locked rotor occurs	0.0
Flux/flow reactor trip setpoint reached	0.13
Rod motion begins	1.33
Turbine trip on reactor trip	1.49
Pressurizer spray initiates	3.27
MSSVs lift	5.04 - 6.55
End of simulation	9.0

9 **Table 15-45. Control Rod Misalignment Accidents - Dropped Rod Accident Sequence of Events**

Event	Time (sec)
Control rod drops	0.0
ICS initiates control rod withdrawal	0.44
Pressurizer spray initiates	17.2
Control rod withdrawal terminates	22.6
End of simulation	60.0

9 **Table 15-46. Turbine Trip Accident Sequence of Events**

Event	Time (sec)
Turbine trip	0.1
MFW isolation	0.1
Main steam safety valves lift	3.0 - 9.2
High RCS pressure trip	3.5
Control rod insertion begins	4.0
Peak RCS pressure occurs	7.5
Main steam safety valves reseat	10.7
End of simulation	50.0

9 **Table 15-47. Steam Generator Tube Rupture Accident Sequence of Events**

Event	Seconds
SGTR occurs	0.1
HPIS injection flow starts	0.1
Reactor trip	1200
Turbine trip on reactor trip	1200
MFW pumps trip	1200
MSSVs lift and begin cycling	1201
EFW flow to ruptured SG begins	1380
Operator identifies EFW control valve is failed closed	1980
EFW to both SG is restored	2580
Operator identifies ruptured SG	3180
Operator begins minimizing subcooled margin	3900
Operator begins cooldown to 532°F with ADVs	5580
All MSSVs have reseated	6130
RCS cooled down to 532°F	6688
Operator completes isolation of the ruptured SG	7289
Operator trips one RCP per loop	7289
Shift changeover begins	7289
Shift changeover completed	10,889
Steaming of ruptured SG due to high SG level begins	11,112
Operator begins RCS cooldown to 450°F	11,189
RCS temperature reaches 450°F. Boron sampling and boration to cold shutdown begins	17,080
Operator begins coolddown to LPIS conditions	24,580
LPIS conditions reached	41,122
Start cooldown with LPIS	43,822
Plant cooled down to 212°F	48,366

9 **Table 15-48. Steam Line Break Accident - Without Offsite Power Case Sequence of Events**

Event	Time (sec)
Break initiates, offsite power lost	0.0
RCPs begin to coast down	
MFW pumps begin to coast down	
Control rod insertion begins	0.14
Turbine stop valves closed	1.76
Control rods fully inserted	2.54
End of simulation	10

9 **Table 15-49. Small Steam Line Break Accident Sequence of Events**

Event	Time (sec)
Break occurs	10
Third Condensate Booster Pump actuates	72
Peak neutron power	194
MDNBR occurs	198
Problem termination	250

Table 15-50. Iodine and Noble Gas Inventory in Reactor Core and Fuel Rod Gaps. 500 EFPD Equilibrium Cycle [1]

Nuclide	Core Inventory (Curies)	Fraction of Inventory in Gap[2,3]	Total Core Gap Inventory (Curies)
I-131	7.16E+7	0.10	7.16E+6
I-132	1.03E+8	0.10	1.03E+7
I-133	1.49E+8	0.10	1.49E+7
I-134	1.73E+8	0.10	1.73E+7
I-135	1.35E+8	0.10	1.35E+7
Xe-131m	4.51E+6	0.10	7.89E+4
Xe-133m	4.51E+6	0.10	4.51E+5
Xe-133	1.39E+8	0.10	1.39E+7
Xe-135m	2.82E+7	0.10	2.82E+6
Xe-135	4.17E+7	0.10	4.17E+6
Xe-138	1.19E+8	0.10	1.19E+7
Kr-83m	8.95E+6	0.10	8.95E+5
Kr-85m	1.90E+7	0.10	1.90E+6
Kr-85	8.30E+5	0.30	2.49E+5
Kr-87	3.66E+7	0.10	3.66E+6
Kr-88	5.15E+7	0.10	5.15E+6

Notes:

1. Based on an equilibrium cycle at end of life. The three-region core operates at a power level of 2619.36 MWth (i.e., 102% of full power).
2. Regulatory Guide 1.25.
3. Regulatory Guide 1.77, Appendix B.

Table 15-51. Reactor Coolant System Fission Product Source Activities - 500 EPFD Equilibrium Cycle [1]

Nuclide	Maximum Specific Activity [2] (μCi/gm)	Maximum Total Coolant Activity [3] (Curies)
I-131	5.80E+0	1.39E+3
I-132	8.36E+0	1.68E+3
I-133	7.03E+0	1.42E+3
I-134	7.76E-1	1.55E+2
I-135	3.32E+0	6.63E+2
Xe-131m	6.04E+0	1.21E+3
Xe-133m	6.42E+0	1.28E+3
Xe-133	4.67E+2	9.32E+4
Xe-135m	7.06E-1	1.41E+2
Xe-135	1.34E+1	2.67E+3
Xe-138	7.40E-1	1.48E+2
Kr-83m	5.34E-1	1.06E+2
Kr-85m	2.23E+0	4.44E+2
Kr-85	1.72E+2	3.43E+4
Kr-87	1.21E+0	2.42E+2
Kr-88	3.81E+0	7.60E+2

Notes:

1. Reactor coolant activities at equilibrium assuming 1 percent failed fuel randomly distributed throughout the core.
2. Based on steady-state operation with no RCS leakage and no continuous pressurizer spray flow. Used for calculating doses arising from reactor coolant leaks to the secondary systems.
3. Based on steady-state operation with no RCS leakage and 1 gpm continuous pressurizer spray flow. Used for calculating rod ejection activity releases to containment.

Table 15-52. Parameters for Steam Generator Tube Rupture Accident Dose Analysis

		Case 1	Case 2
1.	**Data and assumptions used to estimate radioactive sources from postulated accident.**		
	a. Power Level (MWth)	2619.4	Same
	b. Number of failed fuel rods	368	234.3
	c Unruptured steam generator tube leak rate prior to and during accident (gpm)	1.0	Same
2.	**Data and assumptions used to estimate activity released**		
	a. Iodine partition coefficient for steam releases from ruptured steam generator	1.0	Same
	b. Iodine partition coefficient for steam releases from unruptured steam generator	1.0	Same
	c. Iodine partition coefficient in condenser	10,000	Same
	d. Reactor coolant released to ruptured steam generator (lbm)	1.076E+6	Same
	e. Reactor coolant released to unruptured steam generator (lbm)	3.018E+3	Same
3.	**Dispersion data**		
	a. Distance to exclusion area boundary (m)	1.609E+3	Same
	b. Distance to outer boundary of low population zone (m)	9.654E+3	Same
	c. Chi/Q at exclusion area boundary (sec/m3)		
	0-2 hrs (unit vent releases)	3.35E-5	Same
	0-2 hrs (all other releases)	2.20E-4	Same
	d. Chi/Q at low population zone boundary (sec/m3)		
	0-8 hrs	2.35E-5	Same
	8-24 hrs	4.70E-6	Same
	1-4 days	1.50E-6	Same
	4-30 days	3.30E-7	Same
4	**Dose data**		
	a. Method of dose calculations	Reg. Guide 1.4	Same
	b. Dose conversion assumptions	ICRP30 NUREG-1918	Same
	c. Doses (rem)	see Table 15-16	

Table 15-53 (Page 1 of 2). Parameters for Postulated Rod Ejection Offsite Dose Analysis

1.	**Data and assumptions used to estimate radioactive sources from postulated accident.**		
	a. Power Level (MWth)		2619.4
	b. Percent of failed fuel prior to accident		1.0
	c. Steam generator tube leak rate prior to and during accident (gpd)	157 gpd in each OTSG	
	d. Failed fuel	50 percent of fuel rods in core	
	e. Activity released to reactor coolant from failed fuel and available for release.		
	Noble gases	80 percent of core gap inventory	
	Iodines	80 percent of core gap inventory	
	f. Iodine species fractions (organic, elemental, and particulate)	Regulatory Guide 1.4	
2.	**Data and assumptions used to estimate activity released**		
	a. Containment free volume (ft^3)		1.828E+6
	b. Containment leak rate	0.25 percent of containment volume per day, $0 \leq t \leq 24$ hrs. 0.125 percent of containment volume per day, t>24 hrs.	
	c. Bypass leakage fraction		0.50
	d. Iodine partition coefficient for steam releases		1.0
	e. Iodine partition coefficient in condenser		10,000
	f. Primary coolant releases to Reactor Building (lbs)		
	(0-2 hrs)		1,190,439
	(0-8 hrs)		4,576,102
	(0-24 hrs)		--
	(0-4 days)		--
	(0-30 days)		--
	g. Primary coolant leakage to secondary-side of OTSGs (lbs)		
	(0-2 hrs)		71.3
	(0-8 hrs)		314.0
	(0-24 hrs)		1000.8
	(0-4 days)		4116.4
	(0-30 days)		8929.7

Table 15-53 (Page 2 of 2). Parameters for Postulated Rod Ejection Offsite Dose Analysis

	h.	Steam release from steam generators (lbs)	
		(0-2 hrs)	298,058
		(0-8 hrs)	1,166,649
		(0-24 hrs)	1,719,594
		(0-4 days)	2,735,614
		(0-30 days)	4,305,292
3.	**Dispersion data**		
	a.	Distance to exclusion area boundary (m)	1.609E+3
	b.	Distance to outer boundary of low population zone (m)	9.654E+3
	c.	Chi/Q at exclusion area boundary (sec/m3)	
		0-2 hrs (unit vent releases)	3.35E-5
		0-2 hrs (all other releases)	2.20E-4
	d.	Chi/Q at low population zone boundary (sec/m3)	
		0-8 hrs	2.35E-5
		8-24 hrs	4.70E-6
		1-4 days	1.50E-6
		4-30 days	3.30E-7
4	**Dose data**		
	a.	Method of dose calculations	Reg. Guide 1.77 with the following exception: Credit is taken for concurrent RCS releases to RB and primary-to-secondary leakage.
	b.	Dose conversion assumptions	ICRP 30 NUREG-1918
	c.	Doses (rem)	see Table 15-16

Table 15-54. Parameters for Large Main Steam Line Break Accident Dose Analysis

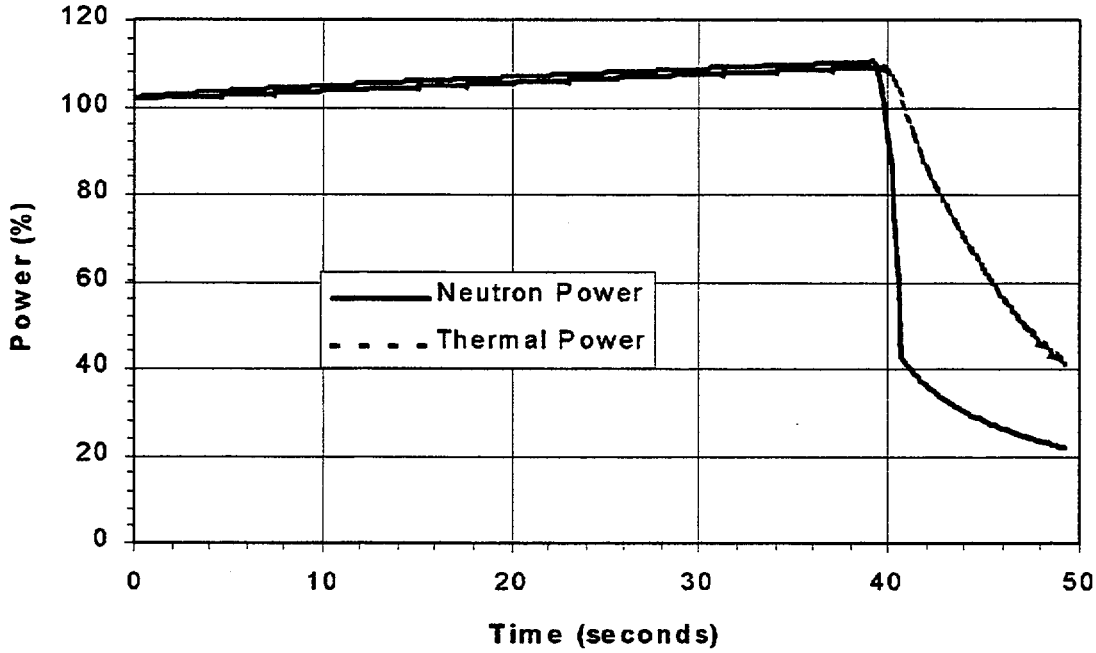
			Case 1	Case 2
1.	**Data and assumptions used to estimate radioactive sources from postulated accident.**			
	a.	Power level (MWth)	2619.4	2619.4
	b.	RCS iodine specific activity [μCi/gm]	1.0	50 times Case 1
	c.	Non-iodine RCS activity	Tech Spec Limit	50 times Case 1
	d.	Faulted OTSG tube leak rate prior to and during accident (gpm)	1.0	Same
	e.	Unfaulted OTSG tube leak rate prior to and during accident (gpd)	150	150
2.	**Data and assumptions used to estimate activity released**			
	a.	Iodine partition coefficient for steam releases	1.0	1.0
	b.	Iodine partition coefficient in condenser	10,000	10,000
	c.	Integrated steam release from steam generators (lbm)		
		1200 sec.	45,920	Same
		4500 sec.	267,359	Same
		7200 sec.	448,779	Same
3.	**Dispersion data**			
	a.	Distance to exclusion area boundary (m)	1.609E+3	Same
	b.	Distance to outer boundary of low population zone (m)	9.654E+3	Same
	c.	Chi/Q at exclusion area boundary (sec/m3)		
		0-2 hrs (unit vent releases)	3.35E-5	Same
		0-2 hrs (all other releases)	2.20E-4	Same
	d.	Chi/Q at low population zone boundary (sec/m3)		
		0-8 hrs	2.35E-5	Same
		8-24 hrs	4.70E-6	Same
		1-4 days	1.50E-6	Same
		4-30 days	3.30E-7	Same
4	**Dose data**			
	a.	Method of dose calculations	Reg. Guide 1.4	Same
	b.	Dose conversion assumptions	ICRP 30 NUREG-1918	Same
	c.	Doses (rem)	see Table 15-16	

Table 15-55. Parameters for Small Main Steam Line Break Accident Dose Analysis

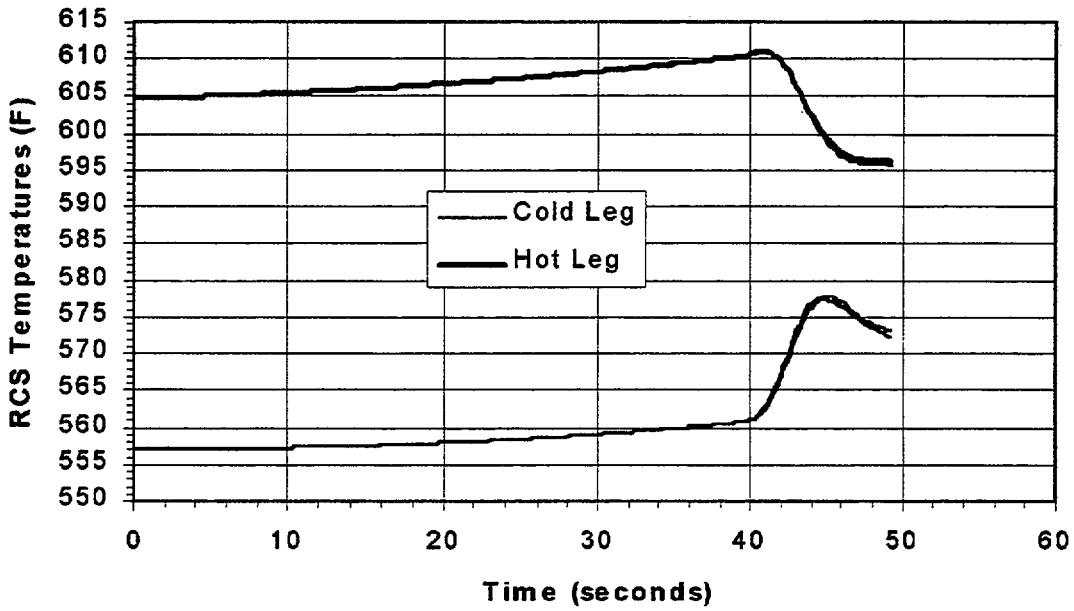
			Case 1	Case 2
1.	**Data and assumptions used to estimate radioactive sources from postulated accident.**			
	a.	Power level (MWth)	2619.4	Same
	b.	RCS iodine specific activity [μCi/gm]	1.0	50 times Case 1
	c.	Non-iodine RCS activity	Tech Spec limit	50 times Case 1
	d.	Faulted OTSG tube leak rate prior to and during accident (gpm)	1.0	Same
	e.	Unfaulted OTSG tube leak rate prior to and during accident (gpm)	150 gpd	Same
2.	**Data and assumptions used to estimate activity released**			
	a.	Iodine partition coefficient for steam releases	1.0	Same
	b.	Iodine partition coefficient in condenser	10,000	Same
	c.	Integrated steam release from steam generators (lbm)		
		1200 sec.	49,216	Same
		4500 sec.	263,318	Same
		7200 sec.	416,196	Same
3.	**Dispersion data**			
	a.	Distance to exclusion area boundary (m)	1.609E+3	Same
	b.	Distance to outer boundary of low population zone (m)	9.654E+3	Same
	c.	Chi/Q at exclusion area boundary (sec/m3)		
		0-2 hrs (unit vent releases)	3.35E-5	Same
		0-2 hrs (all other releases)	2.20E-4	Same
	d.	Chi/Q at low population zone boundary (sec/m3)		
		0-8 hrs	2.35E-5	Same
		8-24 hrs	4.70E-6	Same
		1-4 days	1.50E-6	Same
		4-30 days	3.30E-7	Same
4	**Dose data**			
	a.	Method of dose calculations	Regulatory Guide 1.4	Same
	b.	Dose conversion assumptions	ICRP 30 NUREG-1918	Same
	c.	Doses (rem)	see Table 15-16	

8 Figure 15-9.
8 Deleted Per 1998 Update

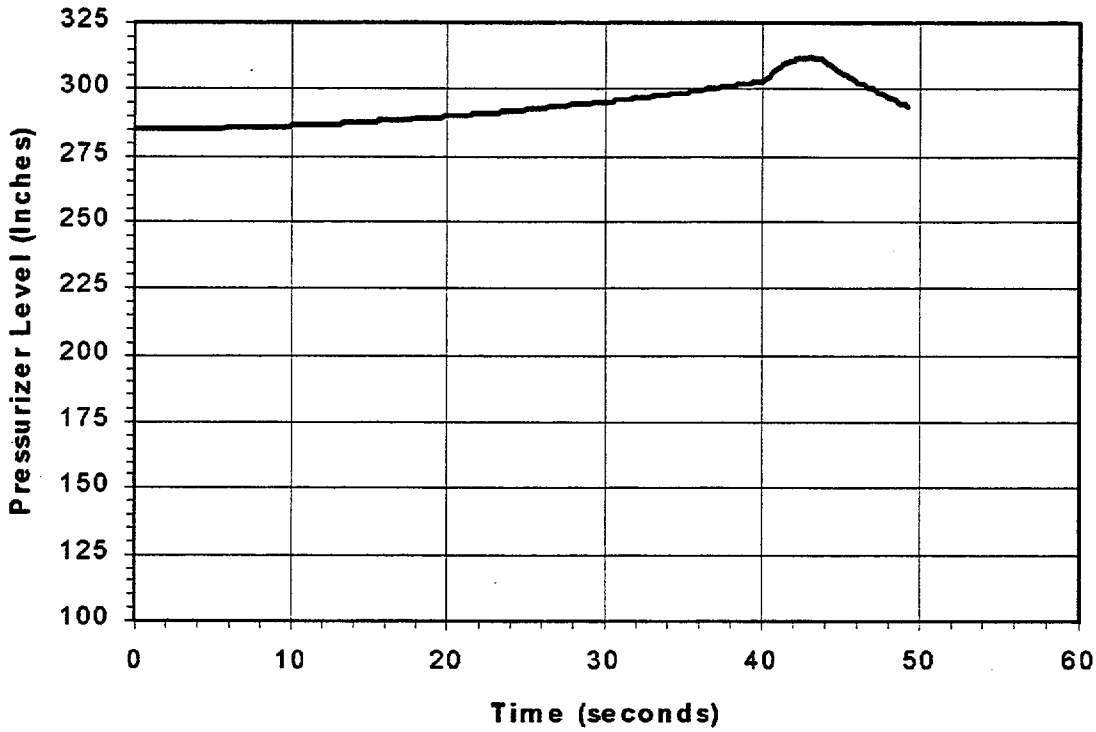
8 Figure 15-10.
8 Deleted Per 1998 Update



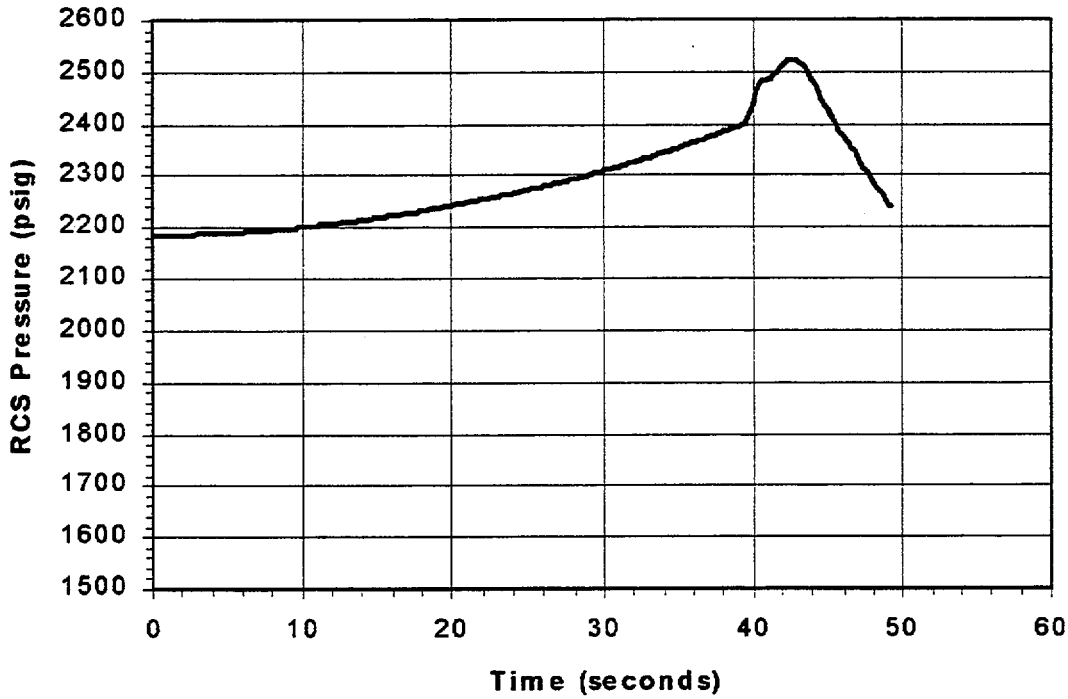
9 Figure 15-11.
9 Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis Power



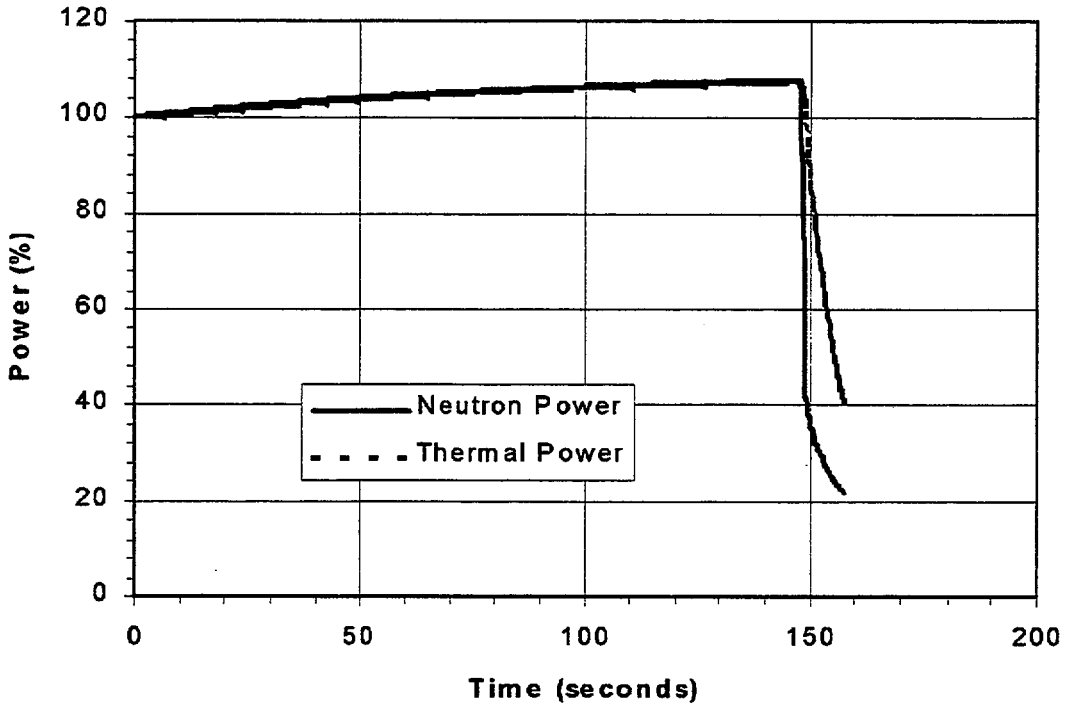
9 Figure 15-12.
9 Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis RCS Temperatures



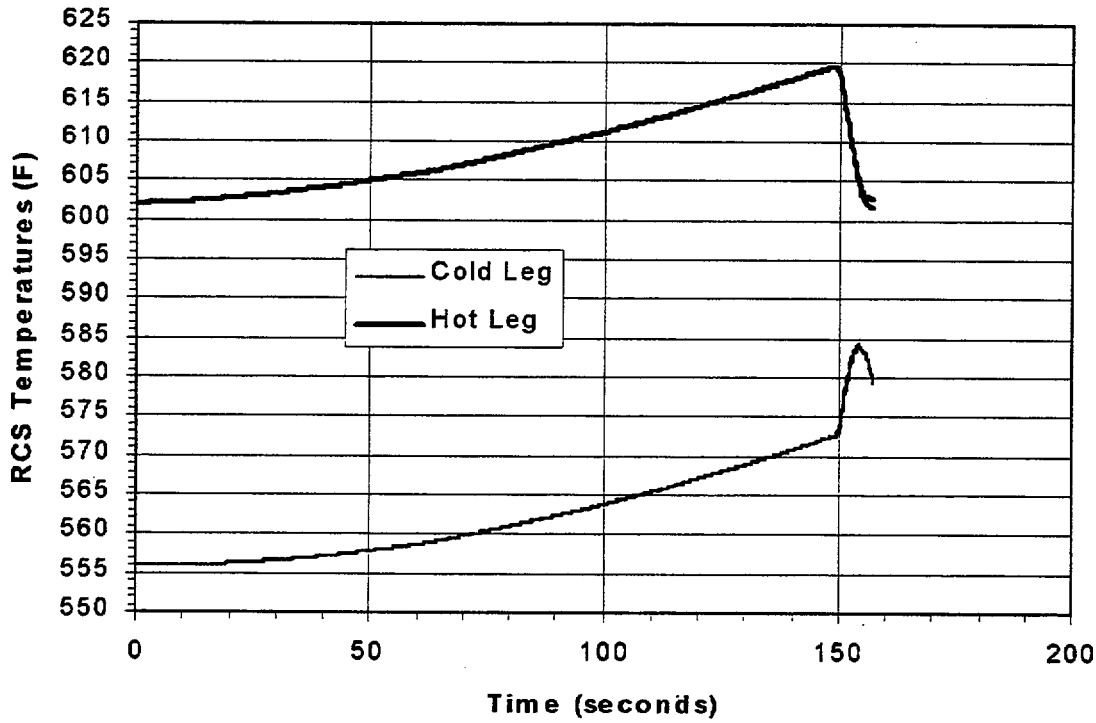
9 Figure 15-13.
9 Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis Pressurizer Level



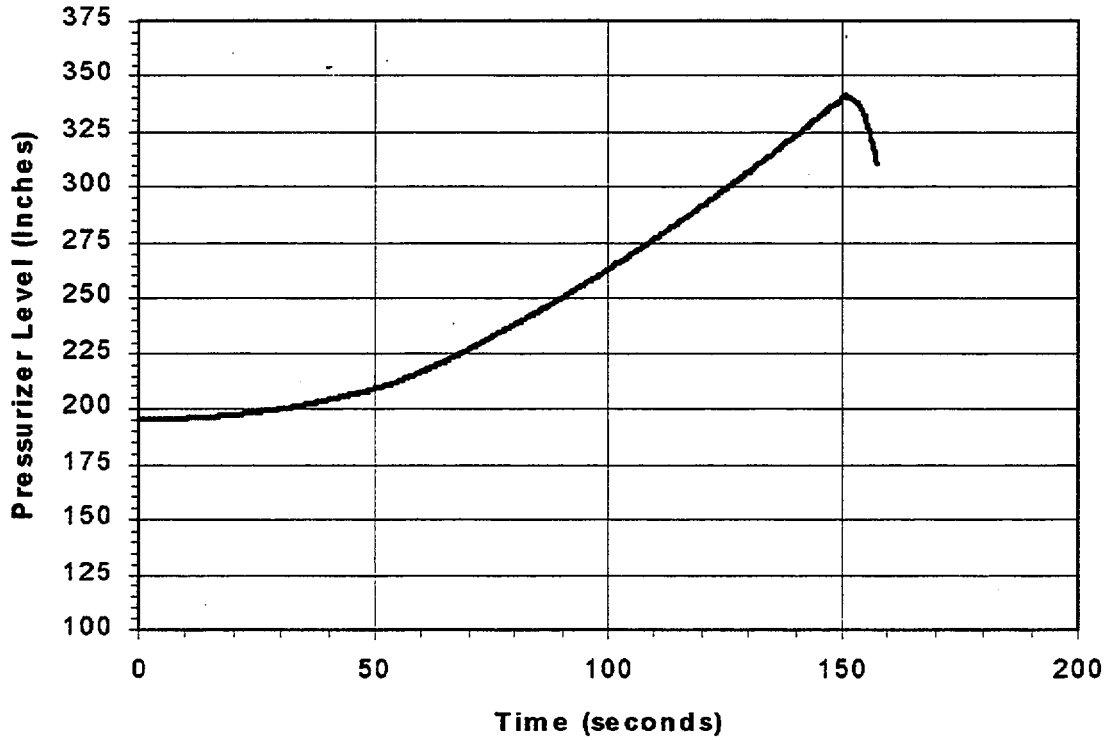
9 Figure 15-14.
9 Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis RCS Pressure



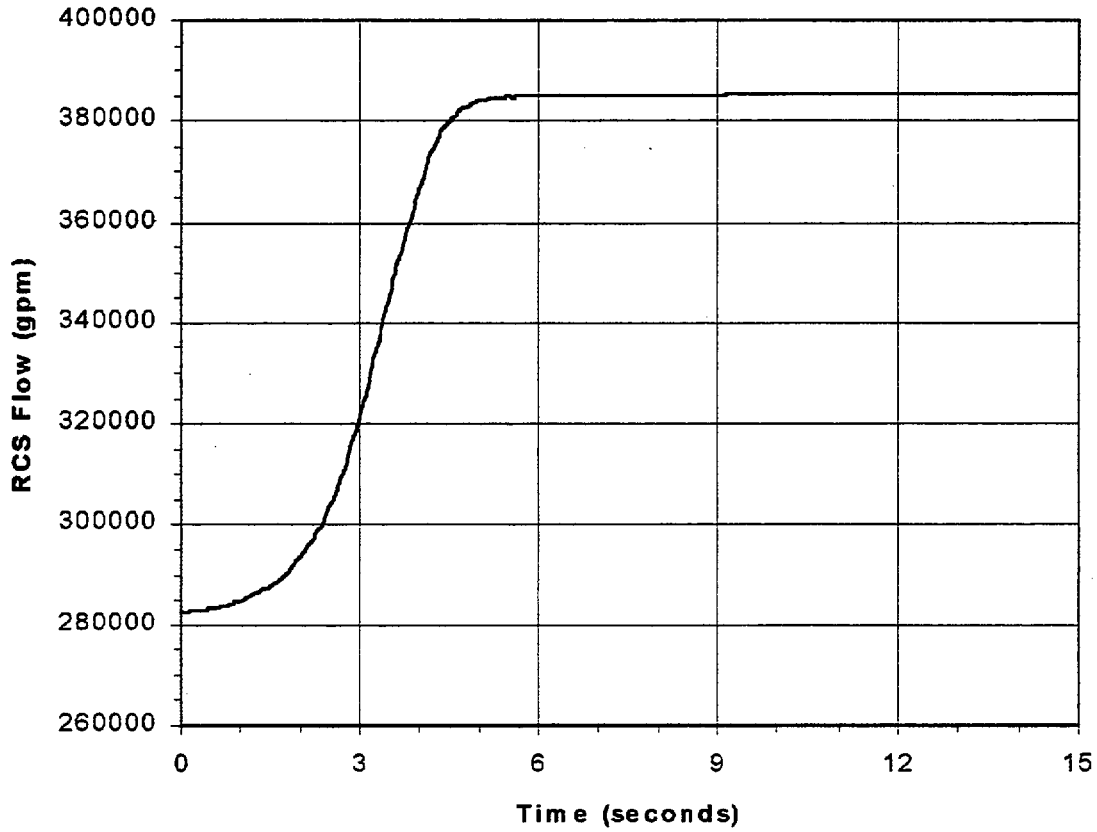
9 Figure 15-15.
9 Rod Withdrawal at Power Accident - Core Cooling Capability Analysis Power



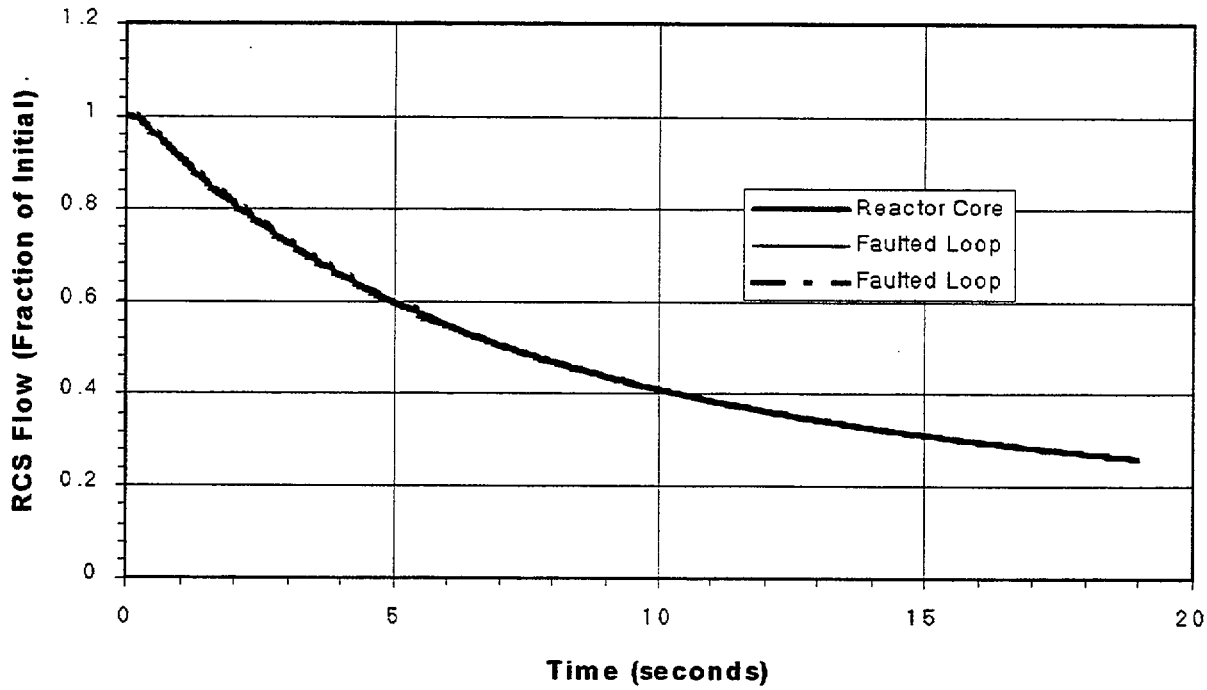
9 Figure 15-16.
9 Rod Withdrawal at Power Accident - Core Cooling Capability Analysis RCS Temperatures



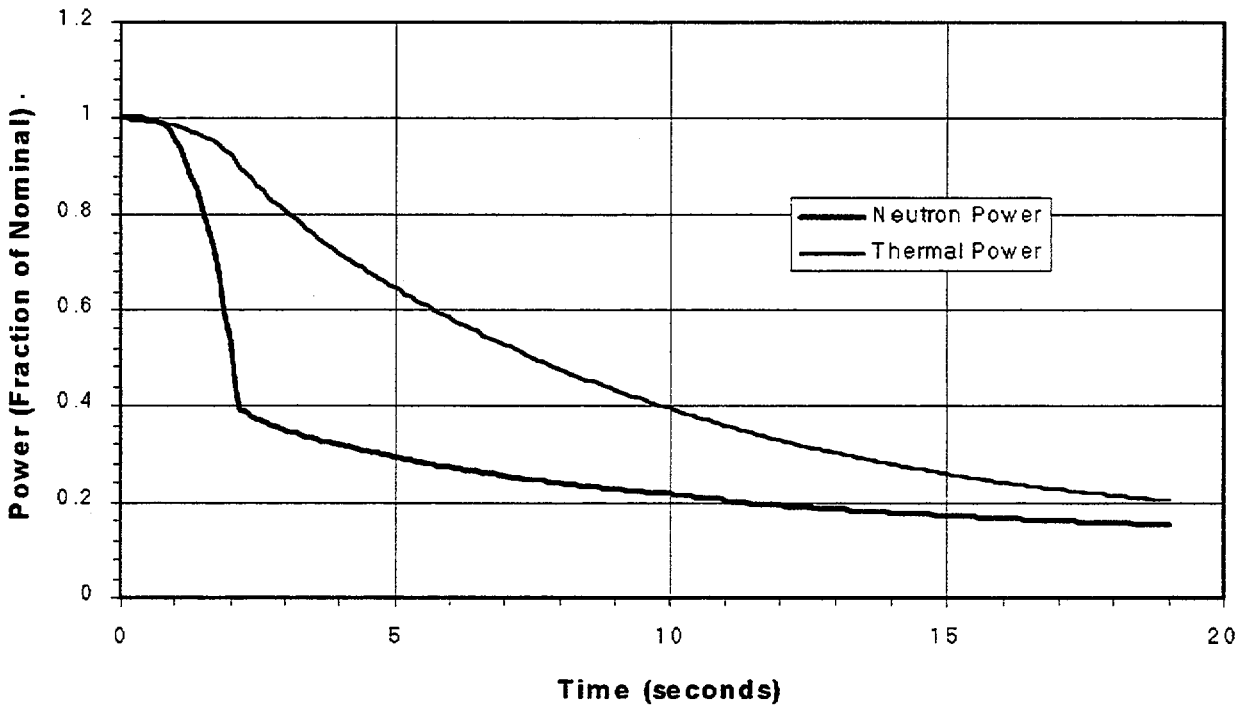
9 Figure 15-17.
9 Rod Withdrawal at Power Accident - Core Cooling Capability Analysis Pressurizer Level



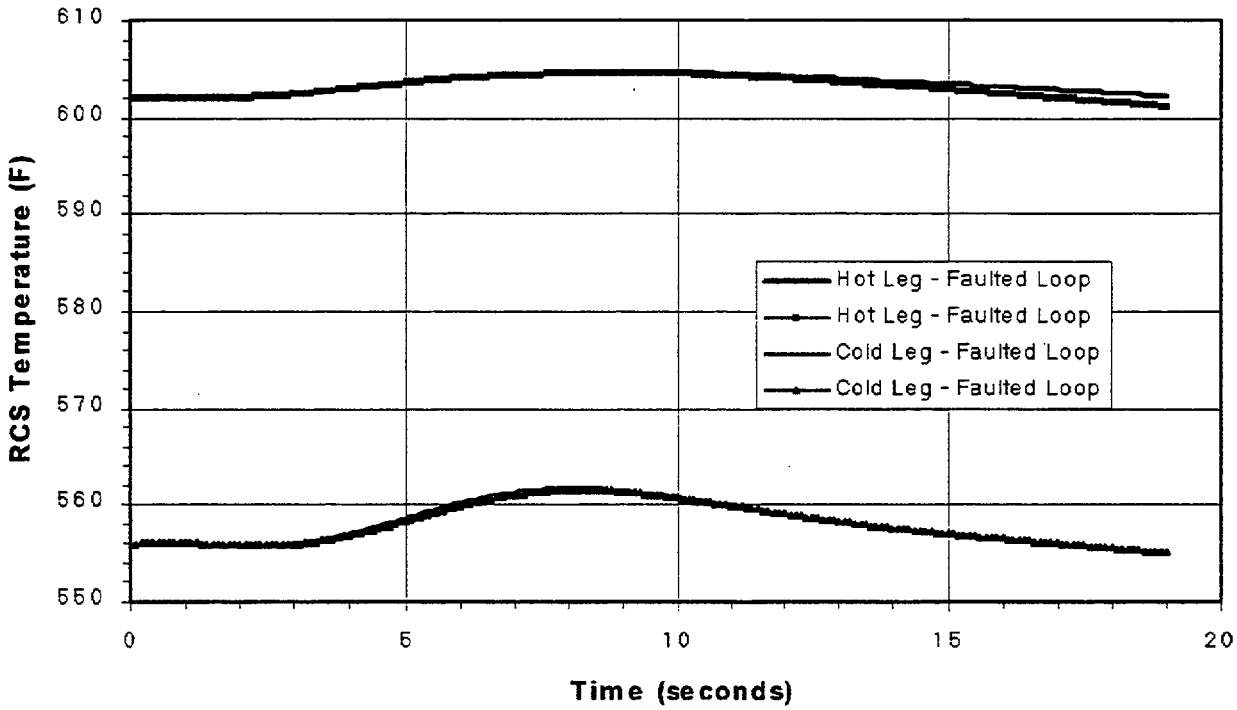
9 Figure 15-18.
9 Cold Water Accident - RCS Flow



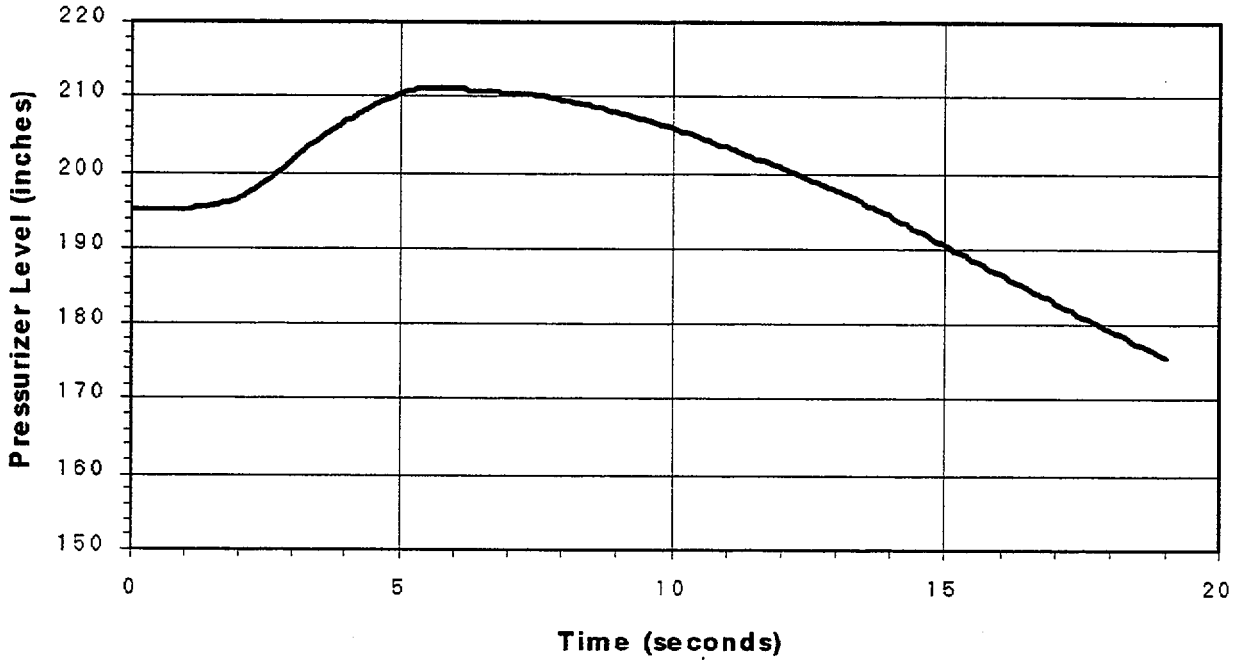
9 Figure 15-19.
9 Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis -
9 RCS Flow



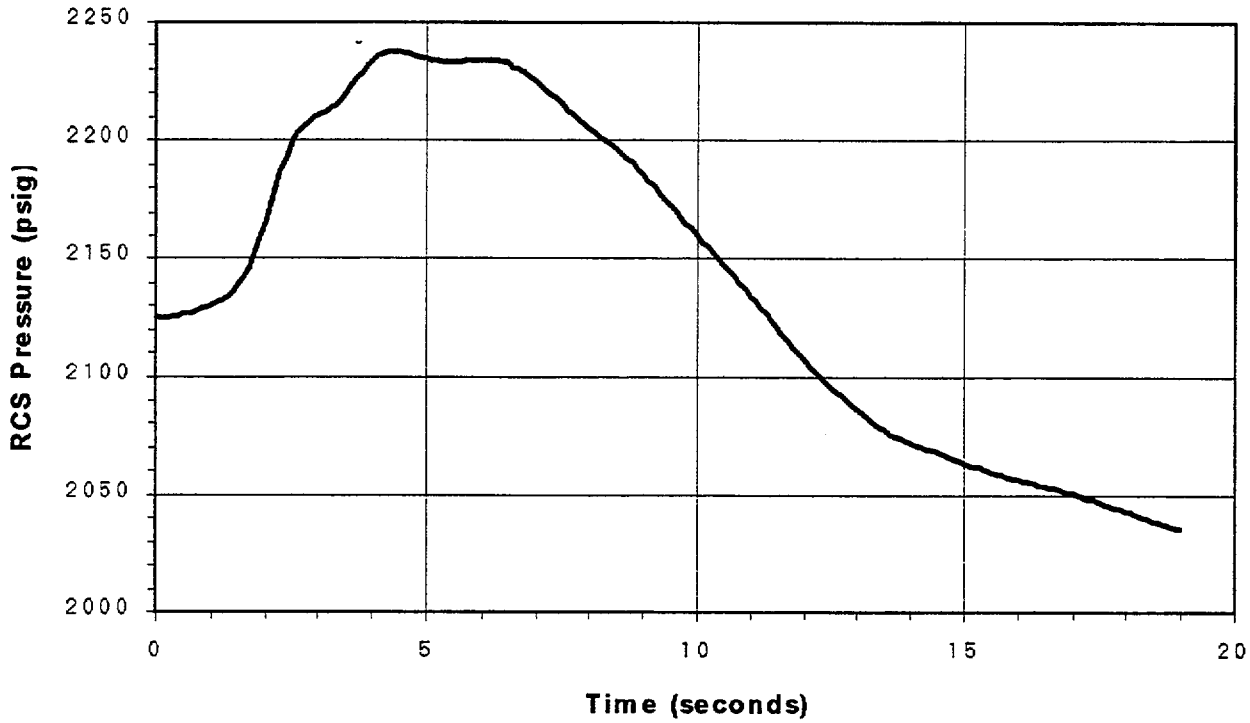
9 Figure 15-20.
9 Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis -
9 Power



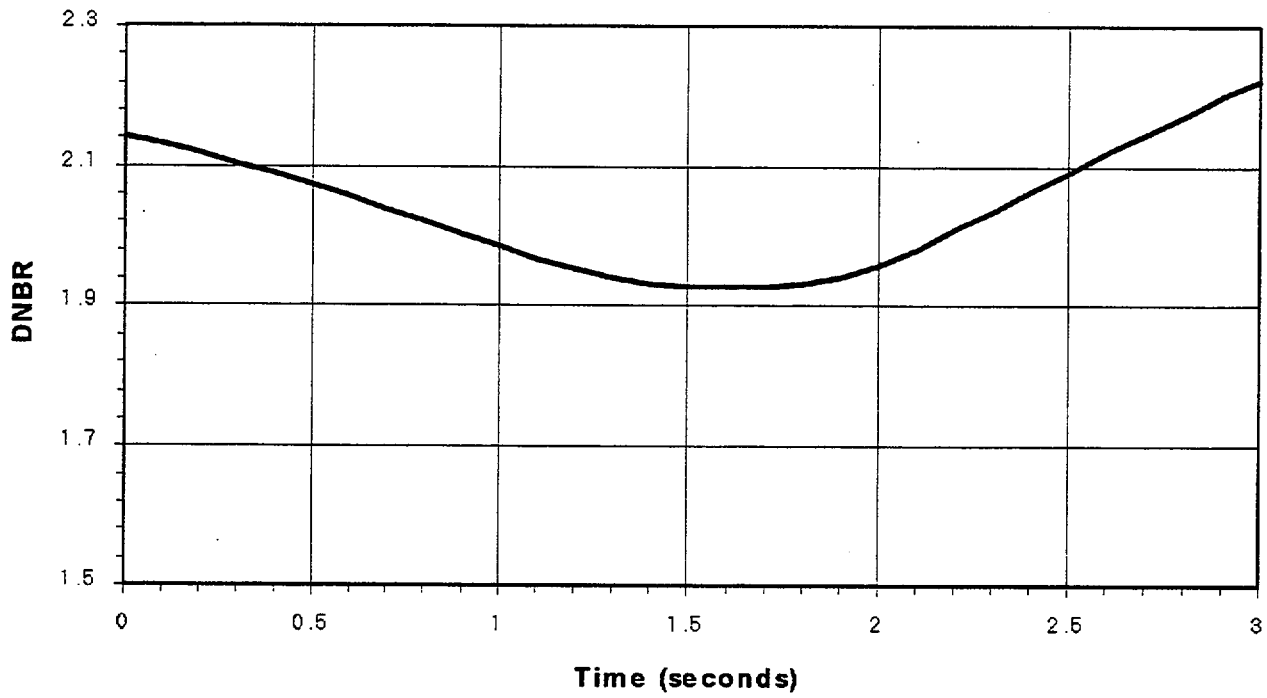
9 Figure 15-21.
9 Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis -
9 RCS Temperature



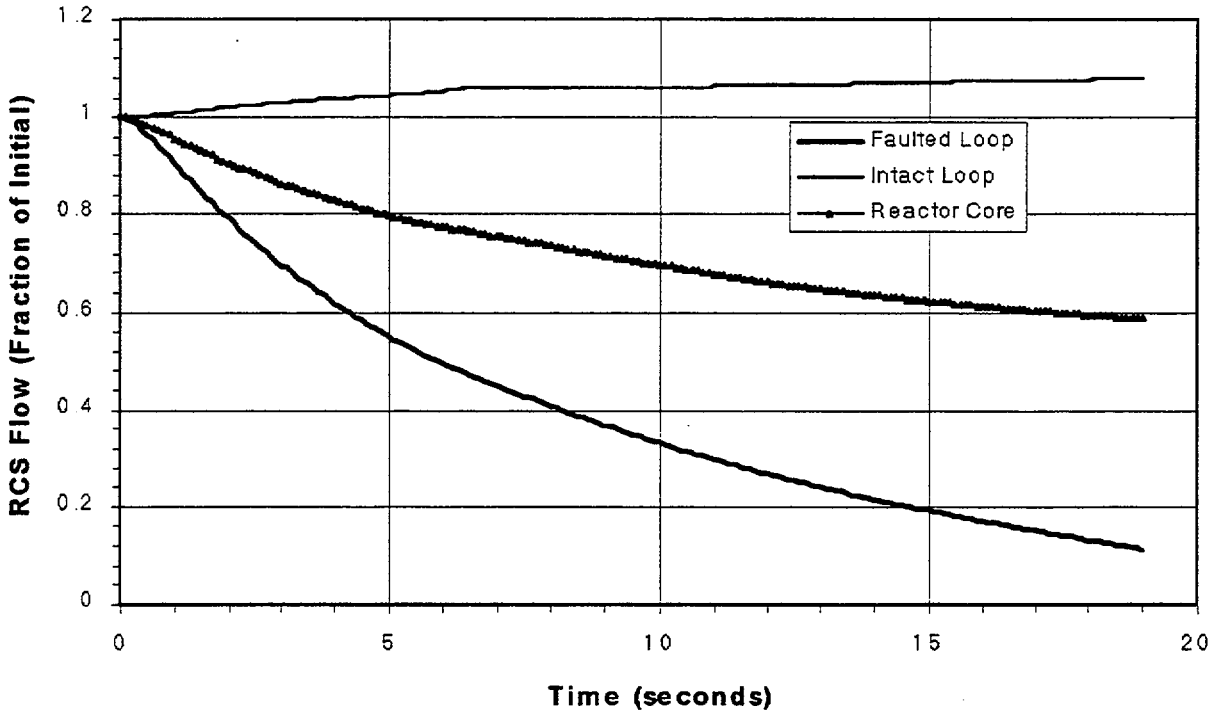
9 Figure 15-22.
9 Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis -
9 Pressurizer Level



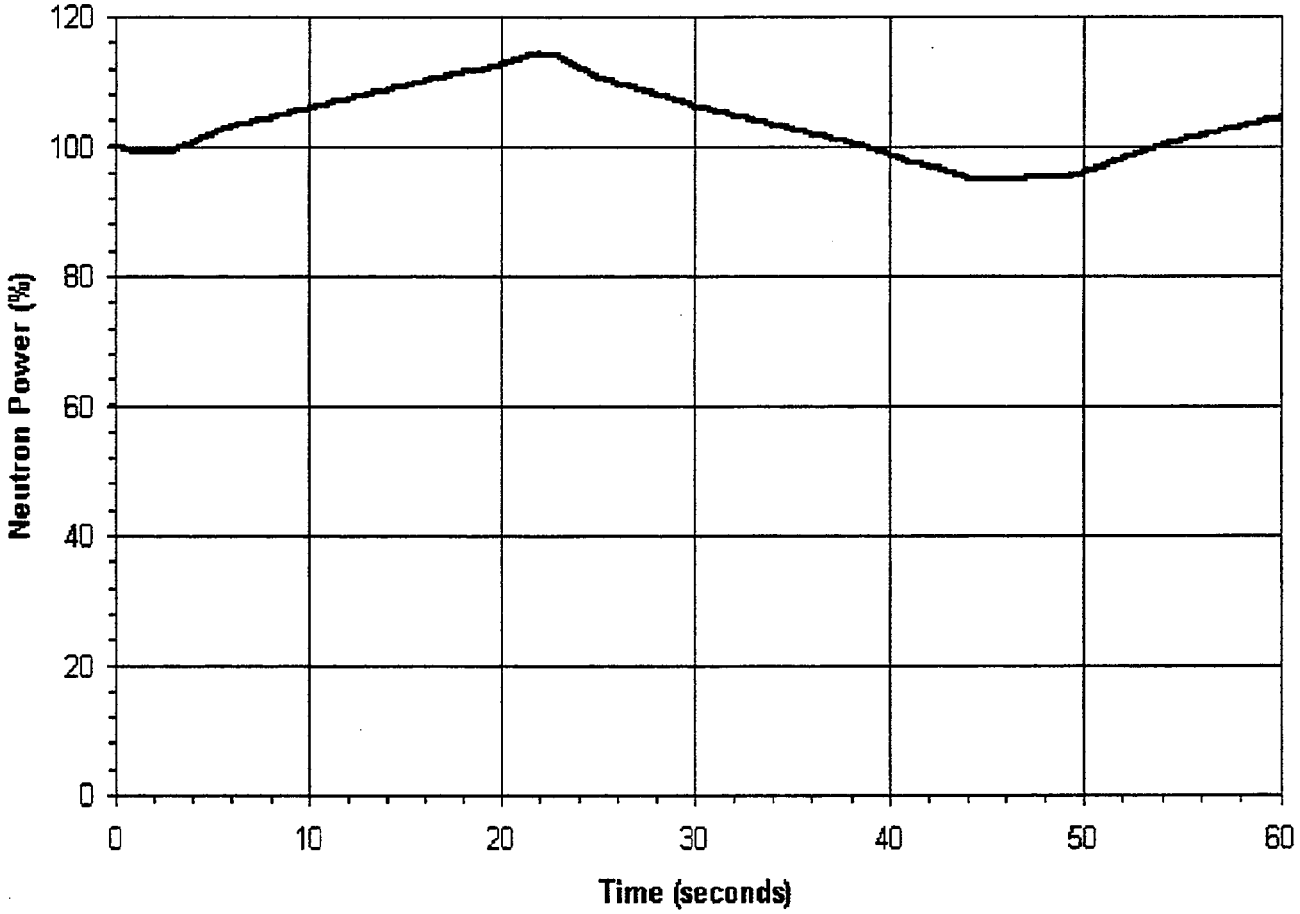
9 Figure 15-23.
9 Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis -
9 RCS Pressure



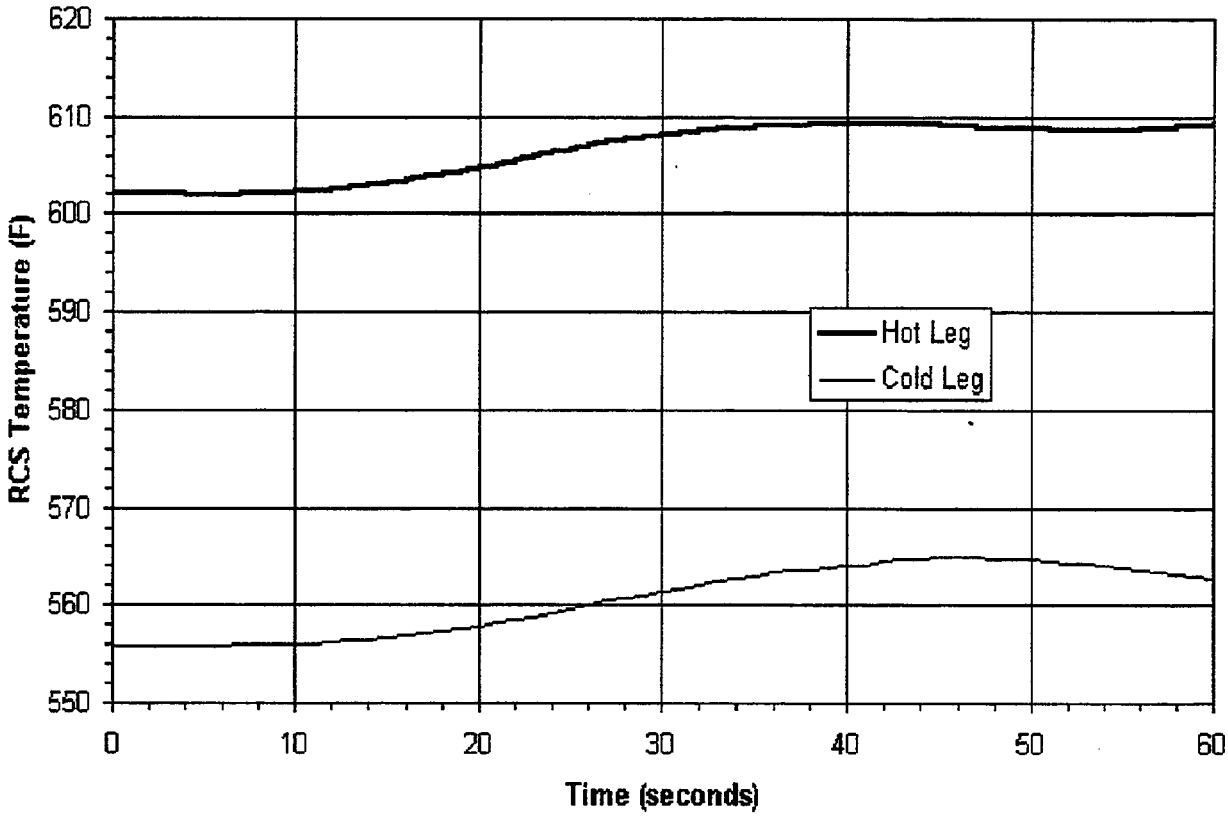
9 Figure 15-24.
9 Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis -
9 DNBR



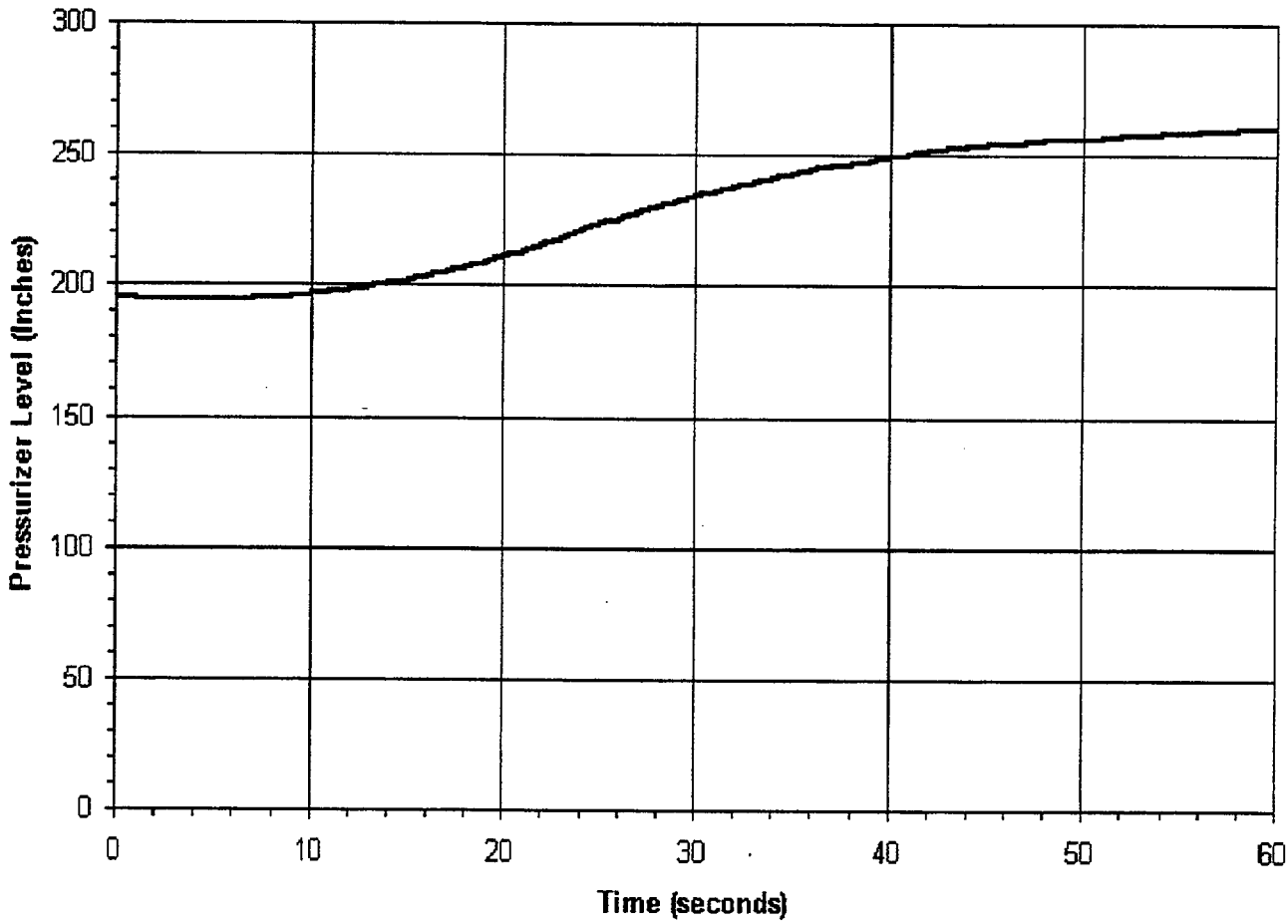
9 Figure 15-25.
9 Loss of Coolant Flow Accidents - Two RCP Coastdown From Four RC P Initial Conditions Analysis -
9 RCS Flow



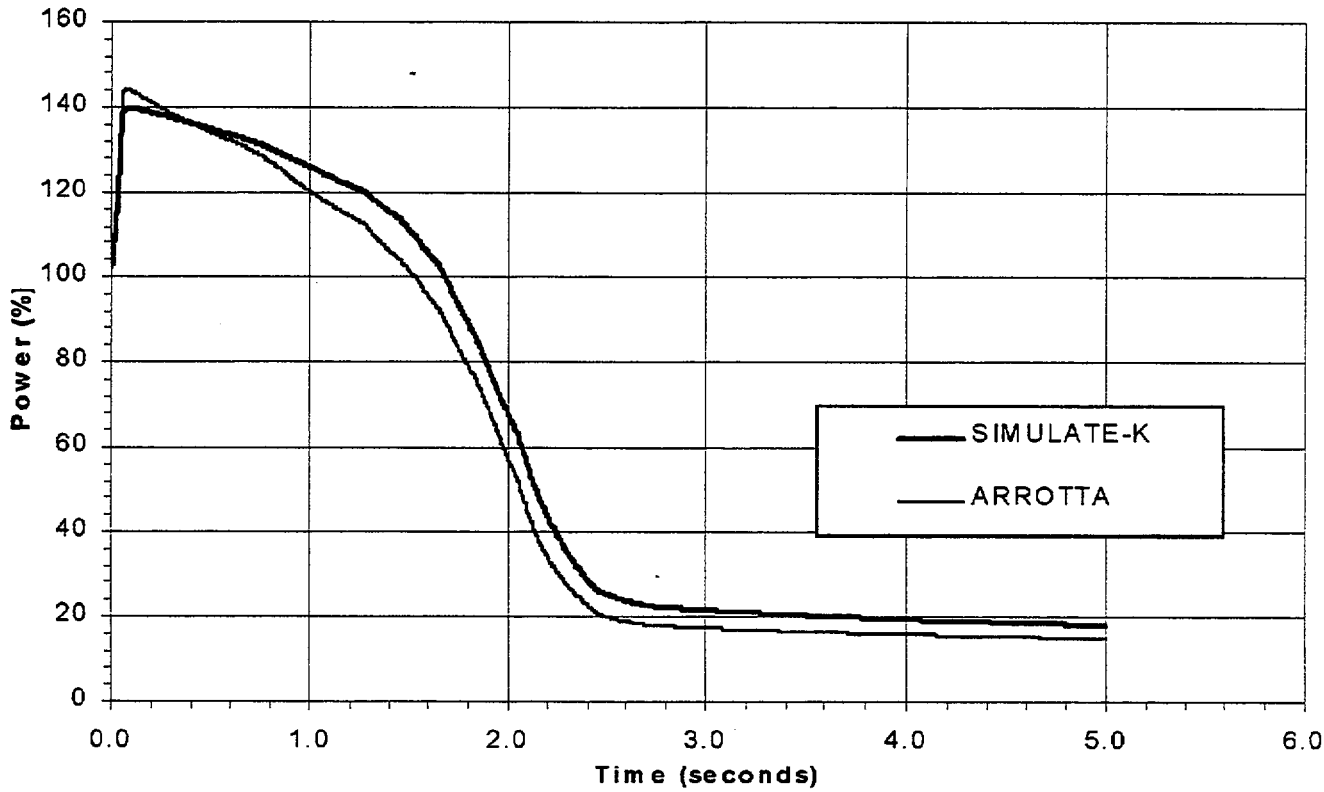
9 Figure 15-26.
9 Control Rod Misalignment Accidents - Dropped Rod Analysis - Neutron Power



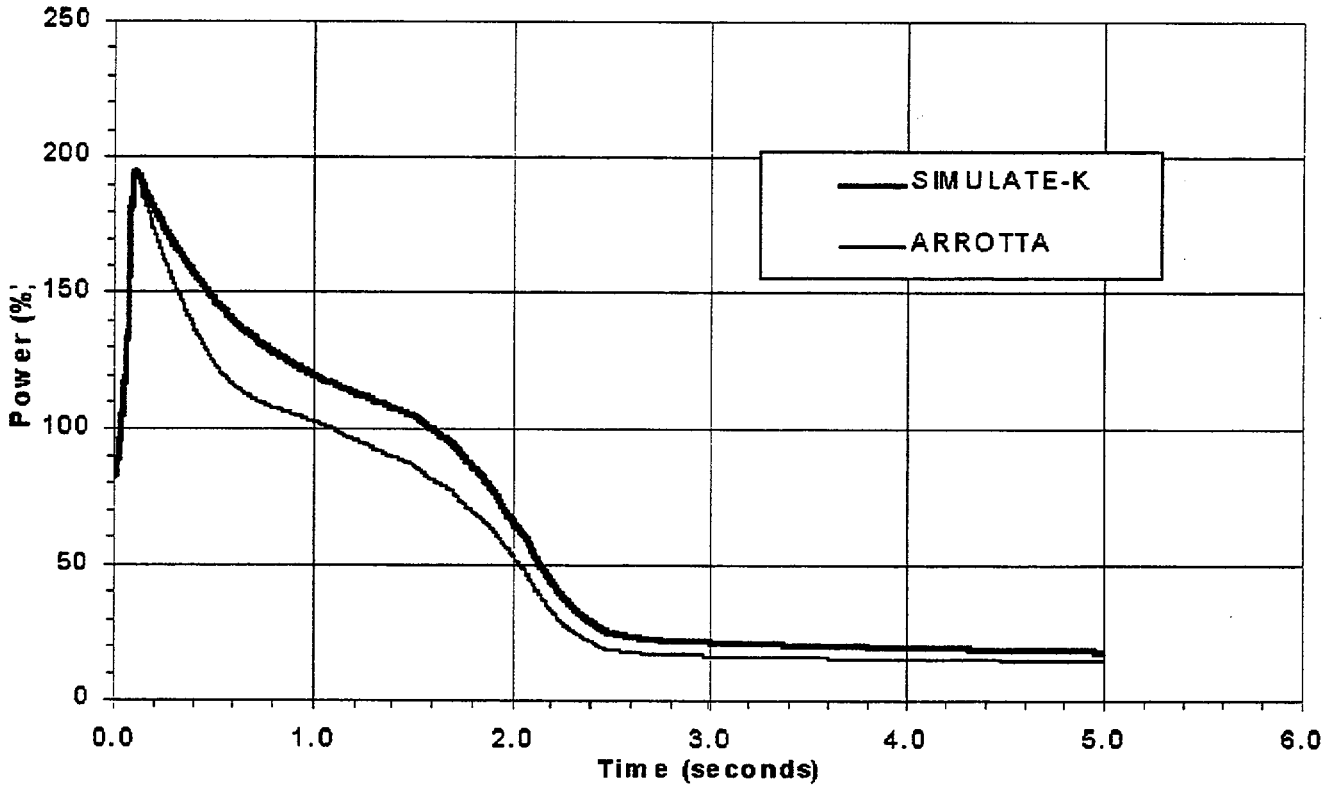
9 Figure 15-27.
9 Control Rod Misalignment Accidents - Dropped Rod Analysis - RCS Temperatures



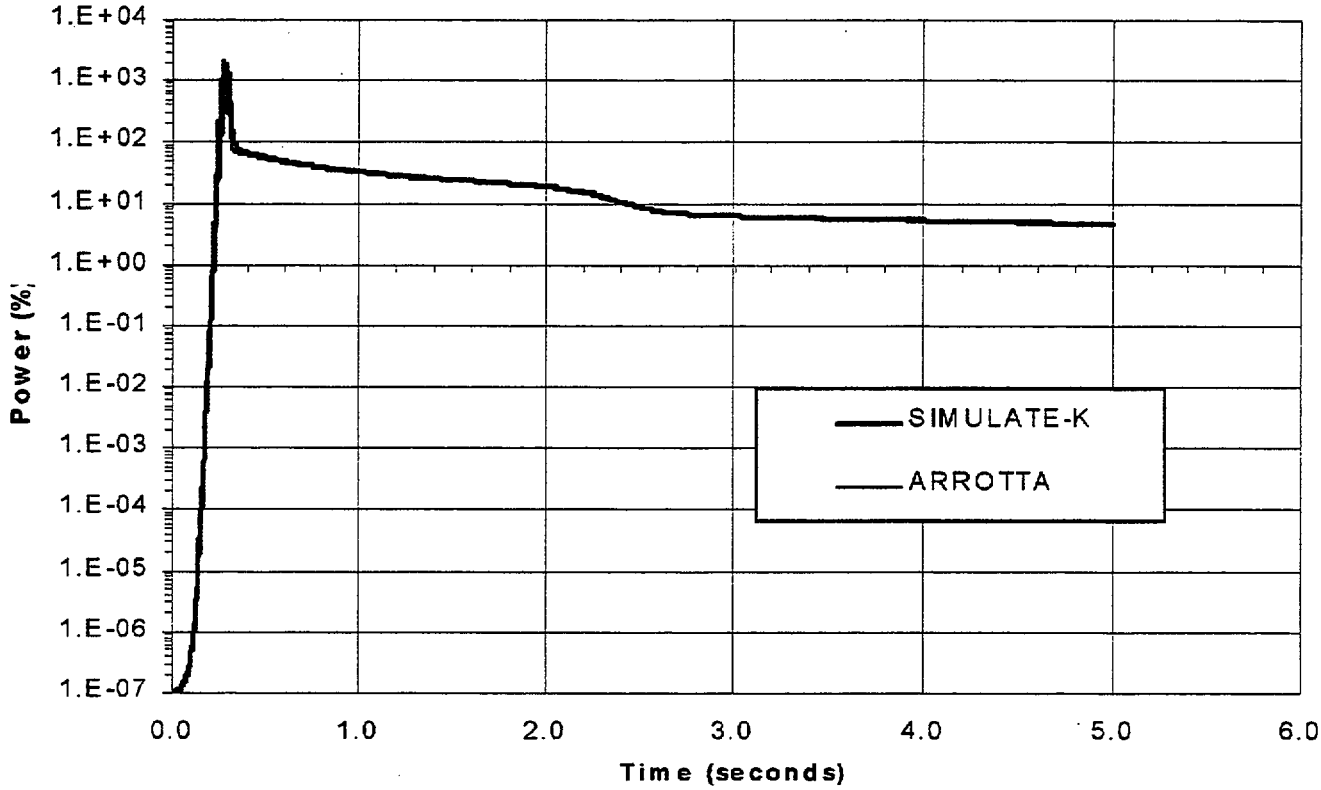
9 Figure 15-28.
9 Control Rod Misalignment Accidents - Dropped Rod Analysis - Pressurizer Level



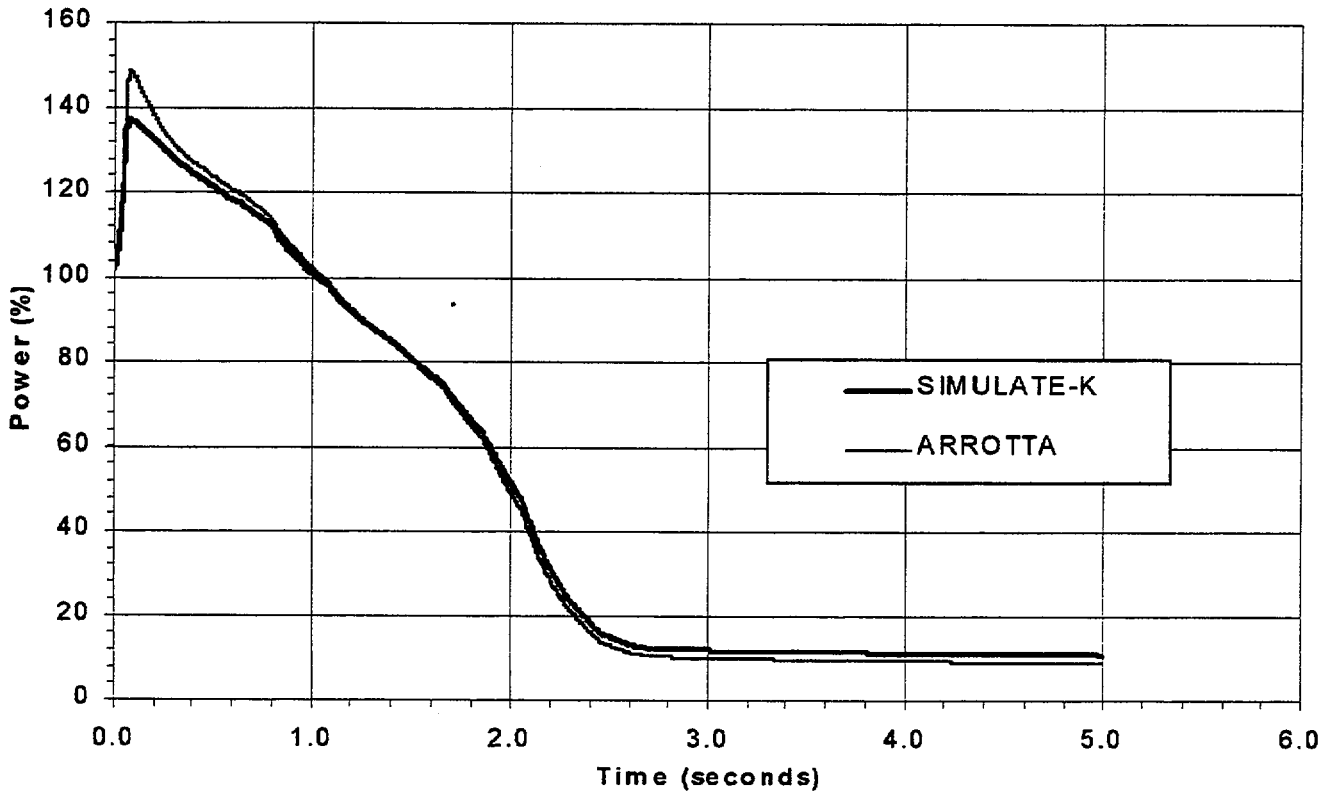
9 Figure 15-29.
9 Rod Ejection Accident - BOC Four RCPs - Power



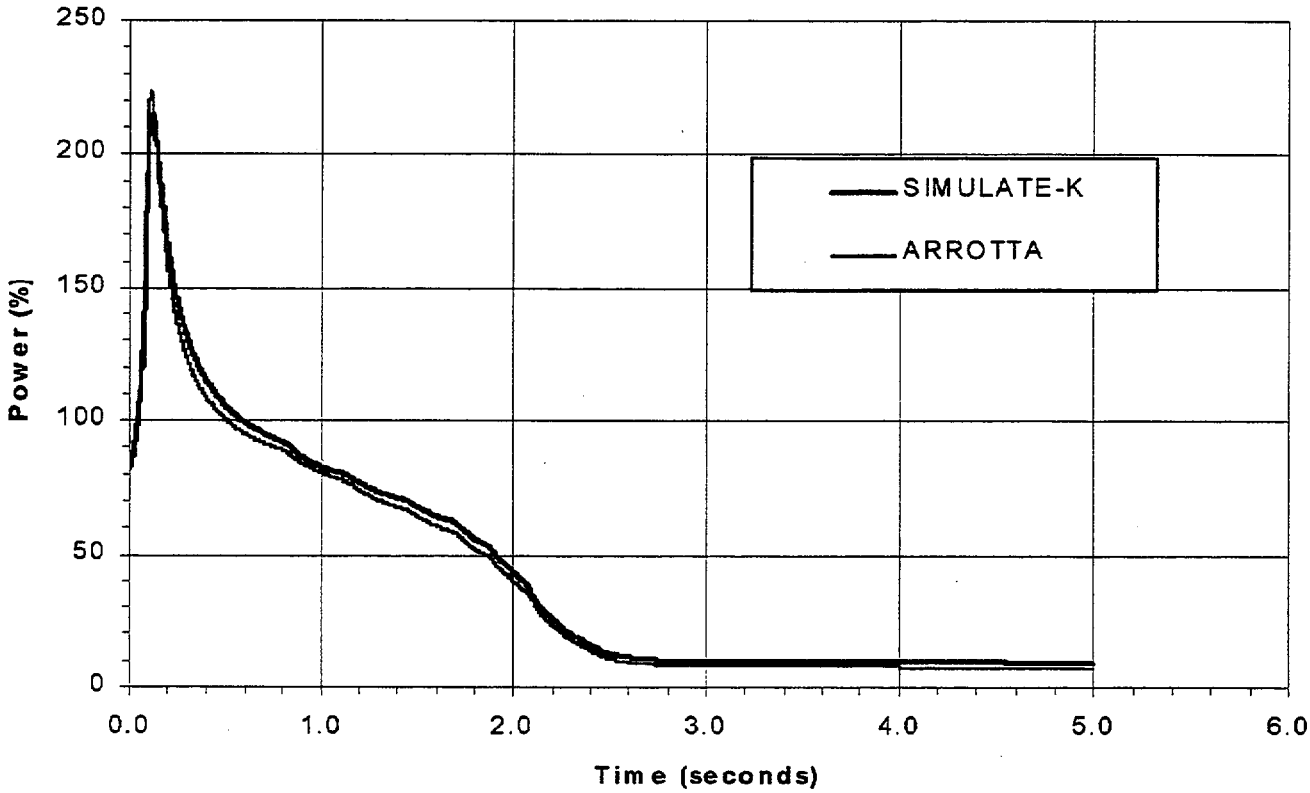
9 Figure 15-30.
9 Rod Ejection Accident - BOC Three RCPs - Power



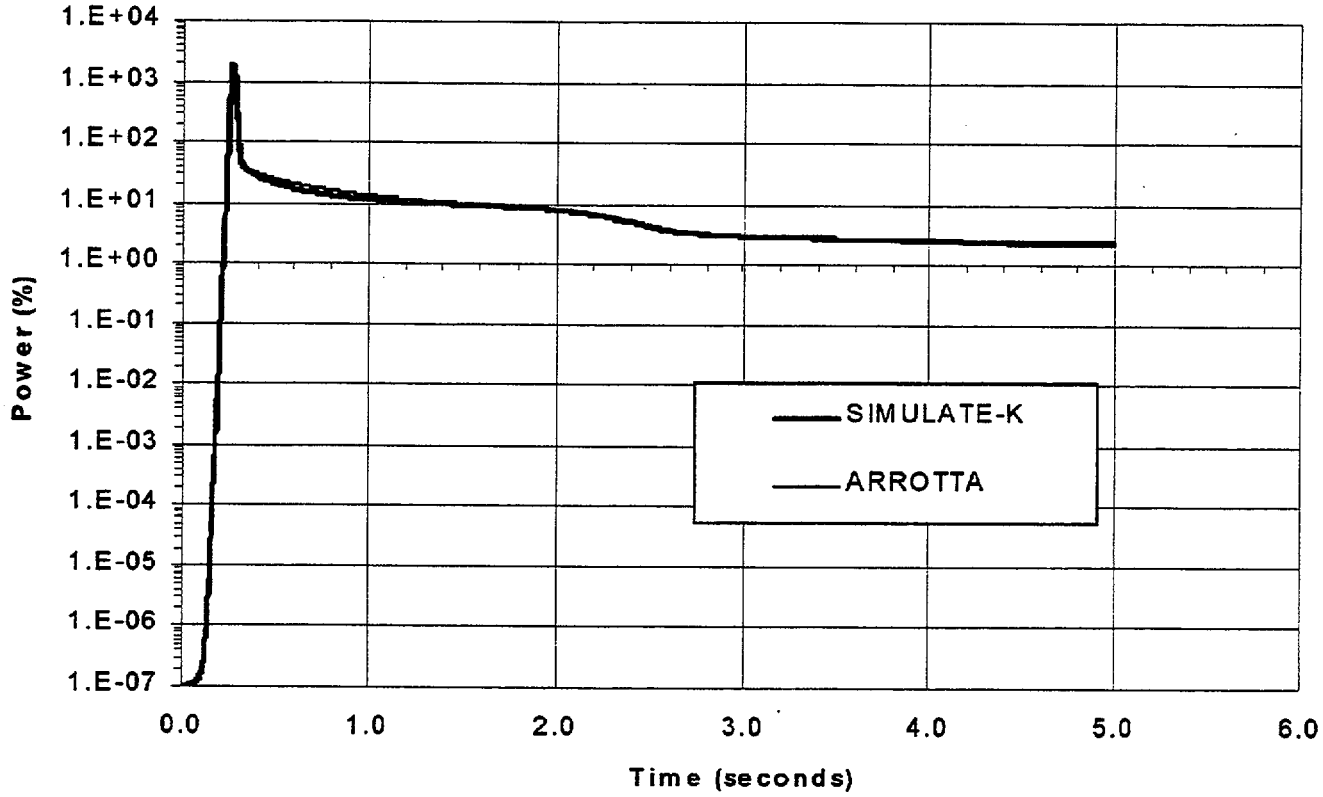
9 Figure 15-31.
9 Rod Ejection Accident - BOC HZP - Power



9 Figure 15-32.
9 Rod Ejection Accident - EOC Four RCPs - Power



9 Figure 15-33.
9 Rod Ejection Accident - EOC Three RCPs - Power

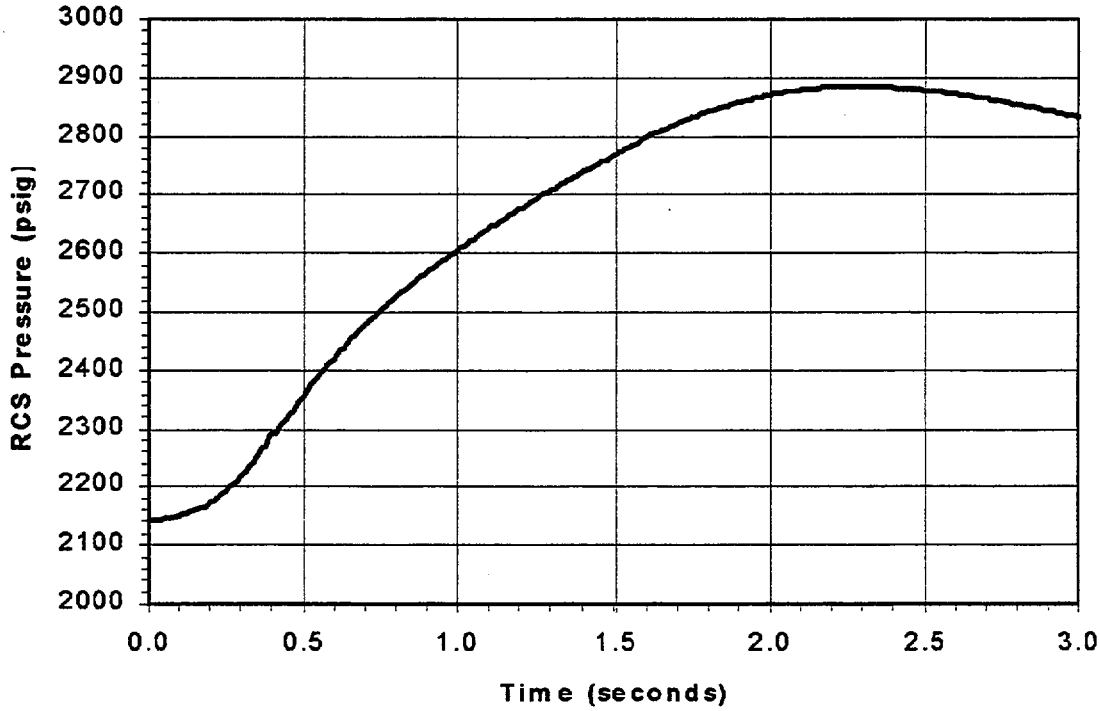


9
9

Figure 15-34.
Rod Ejection Accident - EOC HZP - Power

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
A						0.181	0.270	0.288	0.278	0.192					
B				0.160	0.315	0.898	1.099	0.920	1.138	0.748	0.353	0.185			
C			0.207	0.623	0.744	1.112	1.391	1.389	1.451	1.212	0.857	0.753	0.264		
D		0.153	0.812	0.678	0.994	0.943	1.371	1.282	1.450	1.083	1.195	0.849	0.827	0.222	
E		0.302	0.720	0.975	0.998	1.222	1.448	1.439	1.569	1.441	1.289	1.344	1.052	0.462	
F	0.170	0.659	1.057	0.906	1.190	0.924	1.298	1.251	1.453	1.170	1.670	1.372	1.665	1.066	0.281
G	0.250	1.025	1.302	1.290	1.370	1.249	1.051	1.048	1.233	1.683	2.093	2.151	2.196	1.709	0.424
H	0.263	0.844	1.278	1.190	1.315	1.144	0.978	0.752	1.176	1.590	2.107	2.384	2.233	1.441	0.452
K	0.250	1.025	1.302	1.290	1.370	1.249	1.051	1.048	1.233	1.683	2.093	2.150	2.195	1.707	0.424
L	0.170	0.659	1.057	0.906	1.190	0.924	1.298	1.251	1.453	1.170	1.669	1.372	1.665	1.068	0.281
M		0.303	0.721	0.976	0.998	1.222	1.447	1.439	1.569	1.441	1.289	1.343	1.051	0.461	
N		0.157	0.814	0.679	0.993	0.943	1.370	1.282	1.450	1.083	1.196	0.849	0.824	0.217	
O			0.207	0.621	0.743	1.111	1.391	1.389	1.452	1.212	0.858	0.754	0.264		
P				0.158	0.314	0.898	1.099	0.920	1.138	0.748	0.355	0.180			
R						0.181	0.269	0.288	0.278	0.192					

9 Figure 15-35.
9 Rod Ejection Accident - BOC Four RCPs - Core Power Distribution

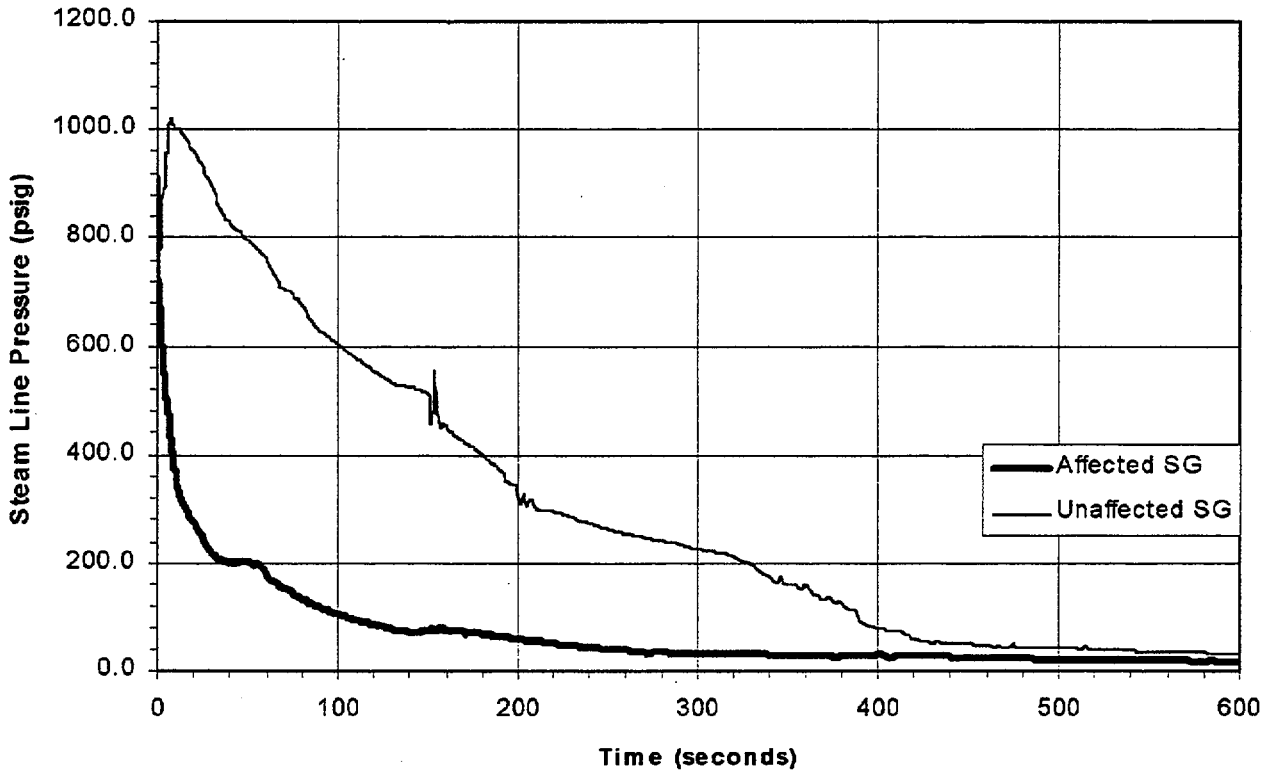


9 Figure 15-36.
9 Rod Ejection Accident - BOC Three RCPs - RCS Pressure

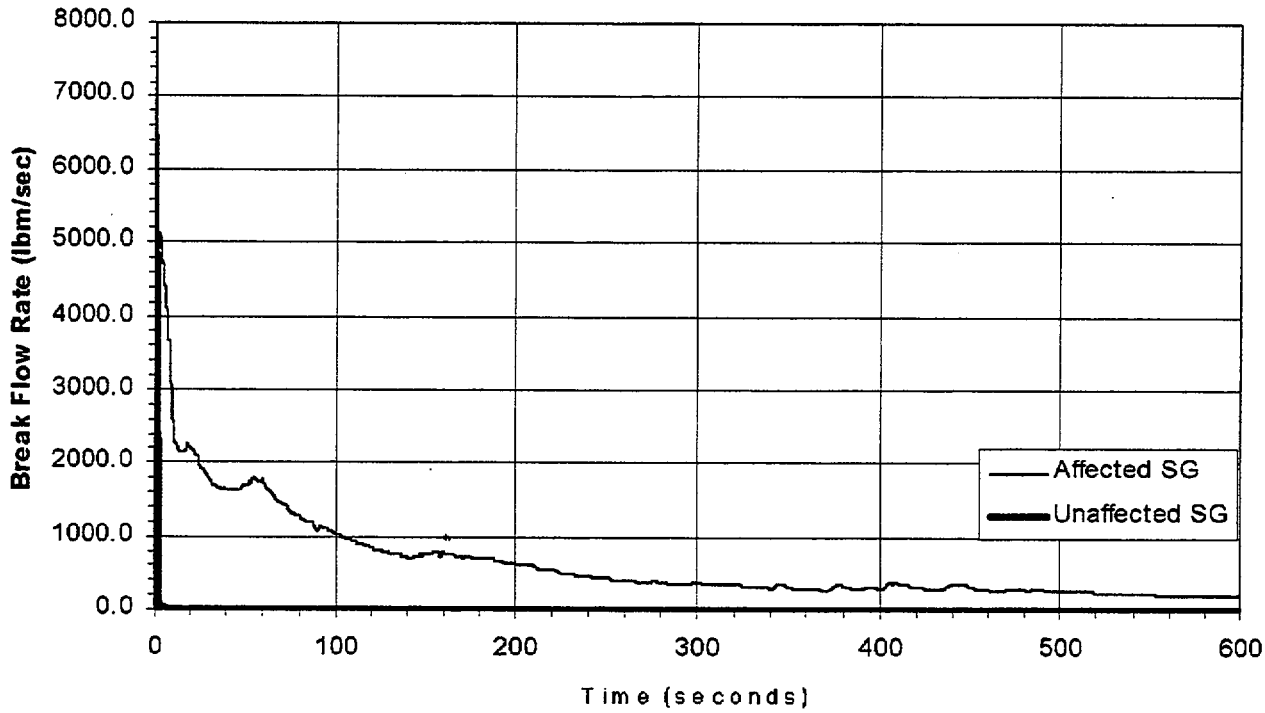
9 Figure 15-37.
9 Deleted Per 1999 Update

9 Figure 15-38.
9 Deleted Per 1999 Update

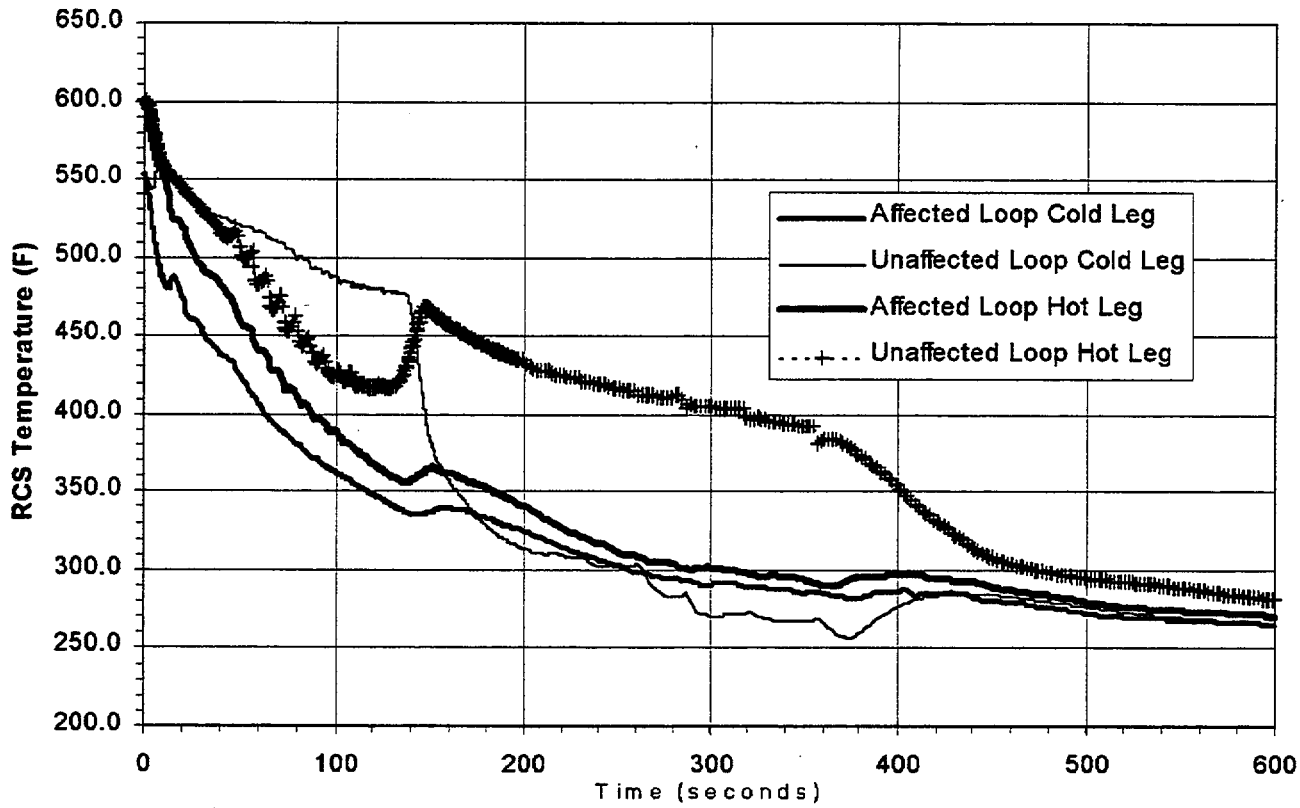
9 Figure 15-39.
9 Deleted Per 1999 Update



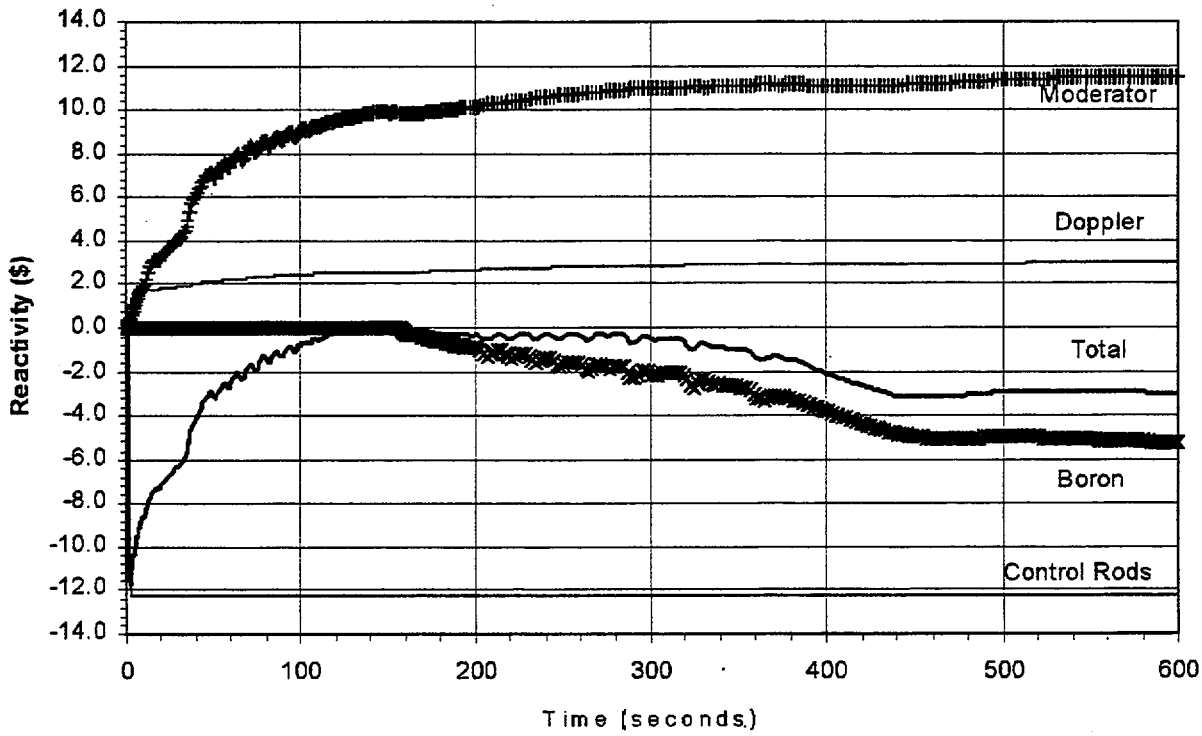
9 Figure 15-40.
9 Steam Line Break Accident - With Offsite Power - Steam Line Pressure



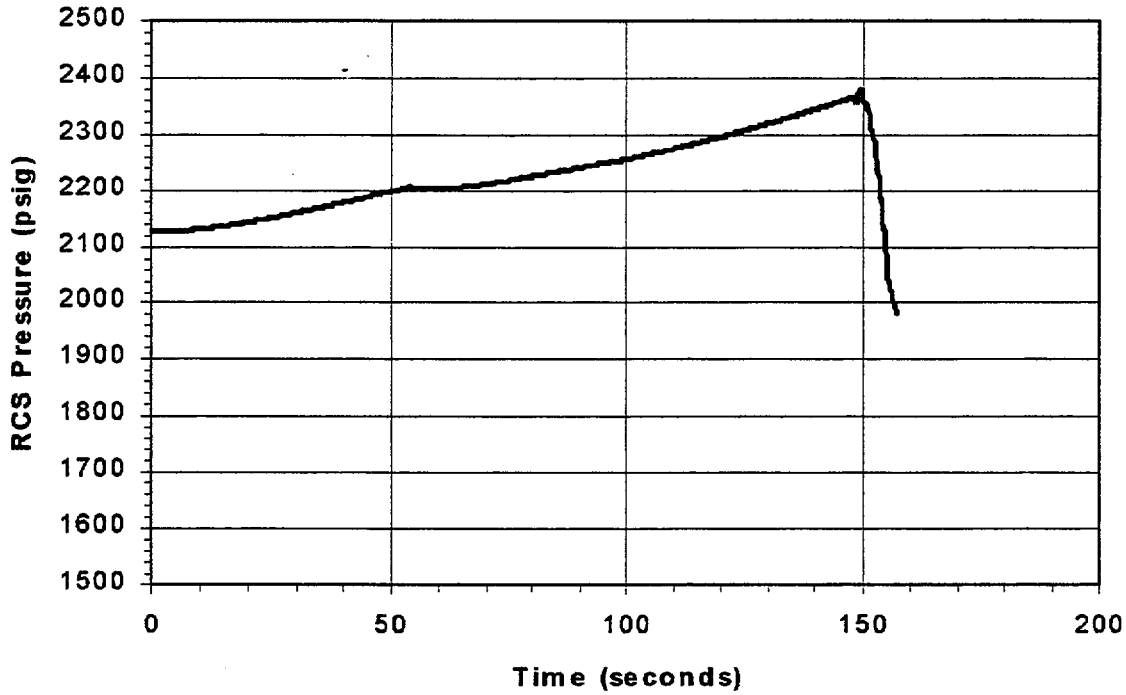
9 **Figure 15-41.**
9 **Steam Line Break Accident - With Offsite Power - Break Flowrate**



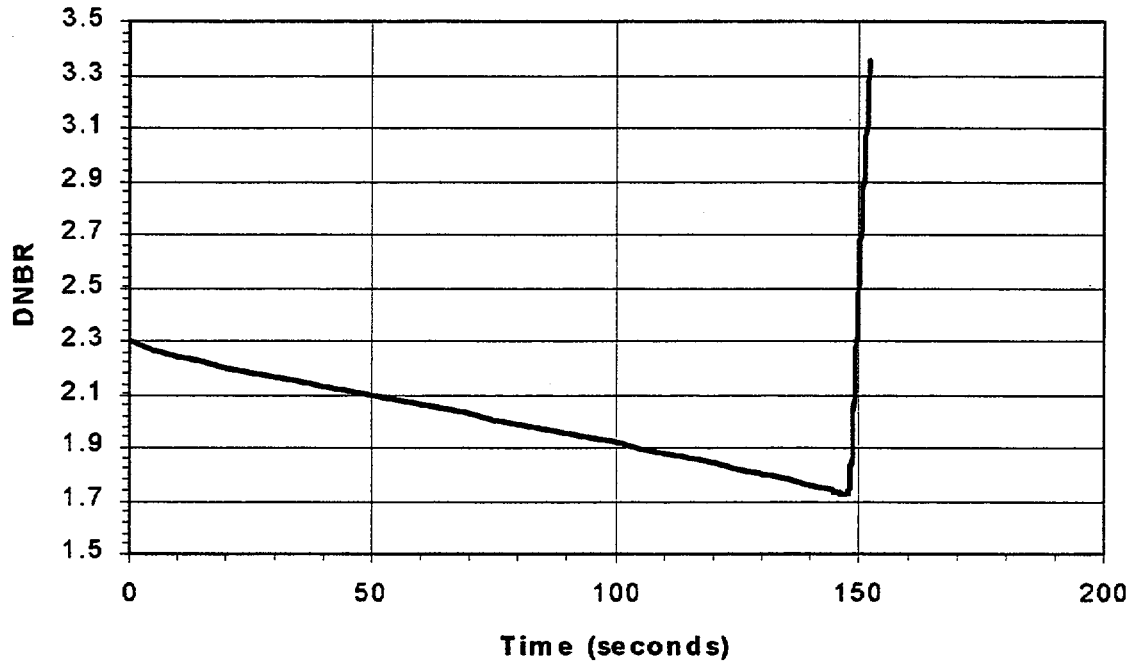
9 Figure 15-42.
9 Steam Line Break Accident - With Offsite Power - RCS Temperature



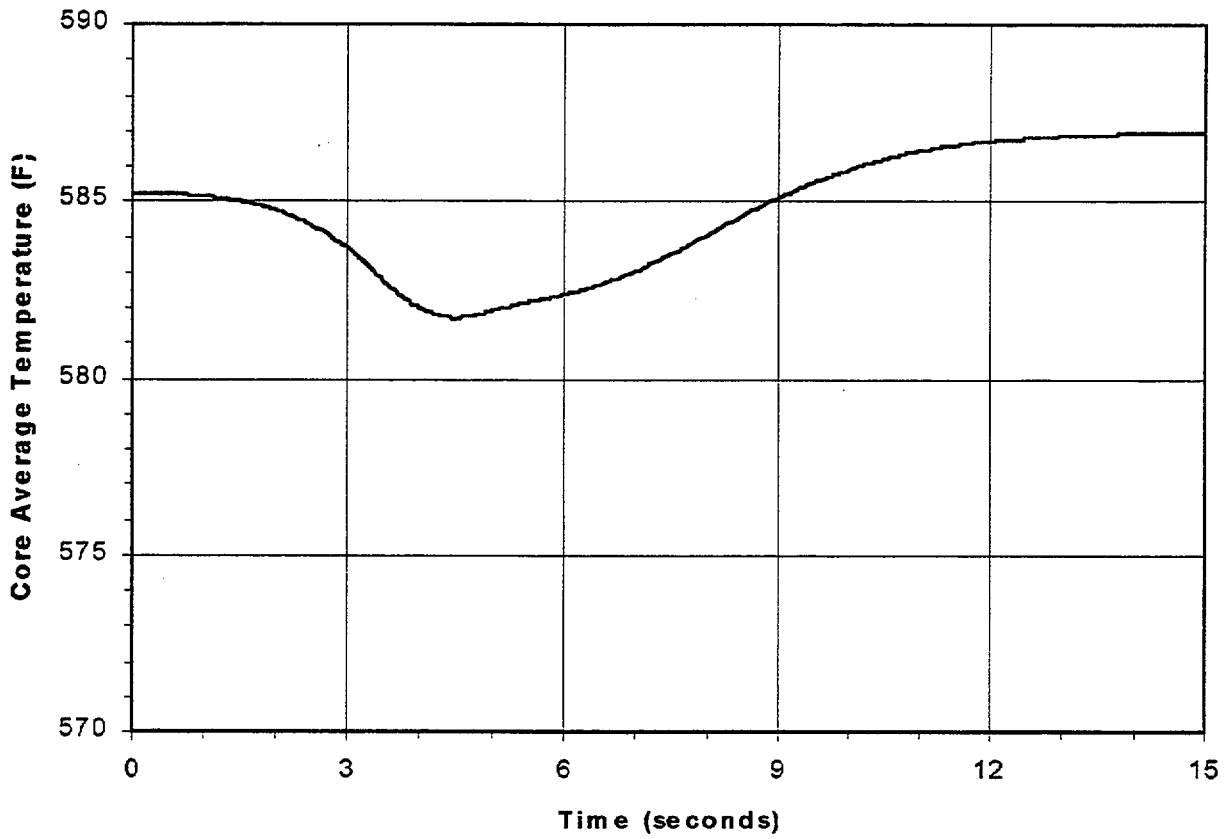
9 **Figure 15-43.**
9 **Steam Line Break Accident - With Offsite Power - Reactivity**



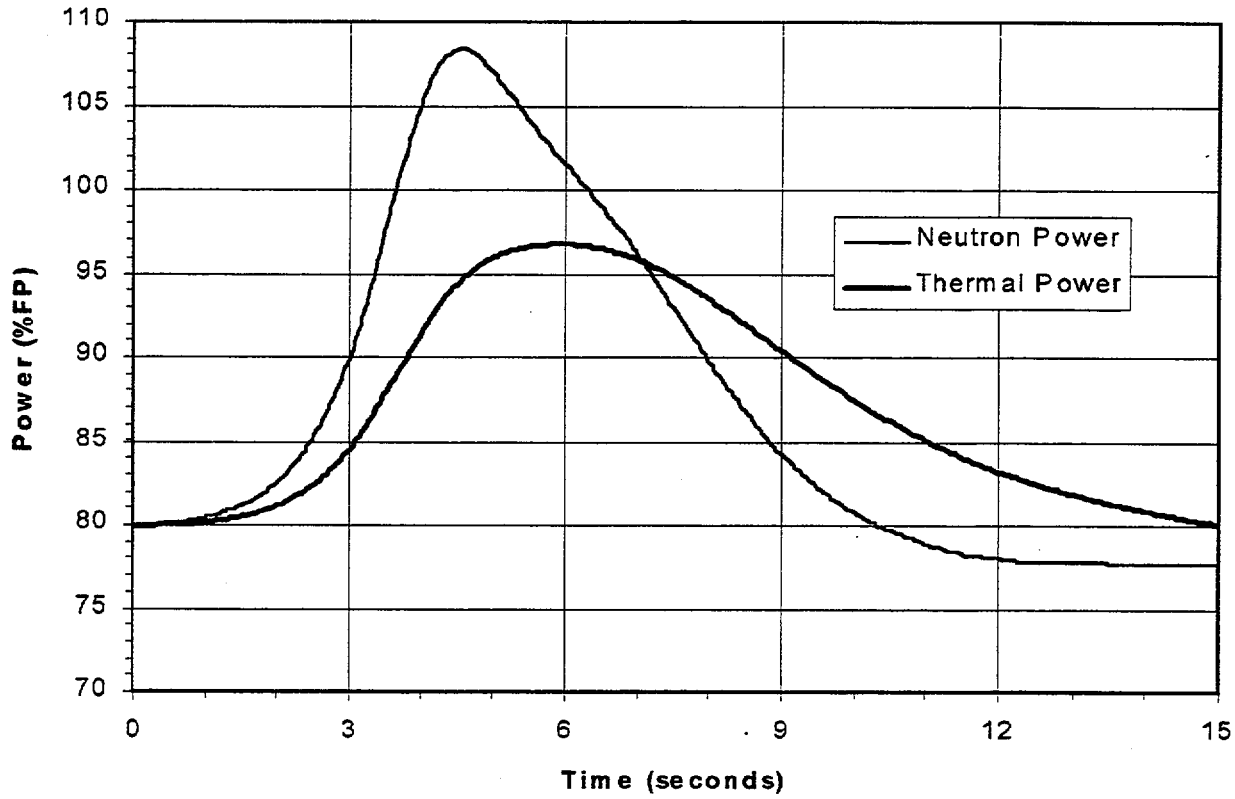
9 Figure 15-113.
9 Rod Withdrawal at Power Accident - Core Cooling Capability Analysis RCS Pressure



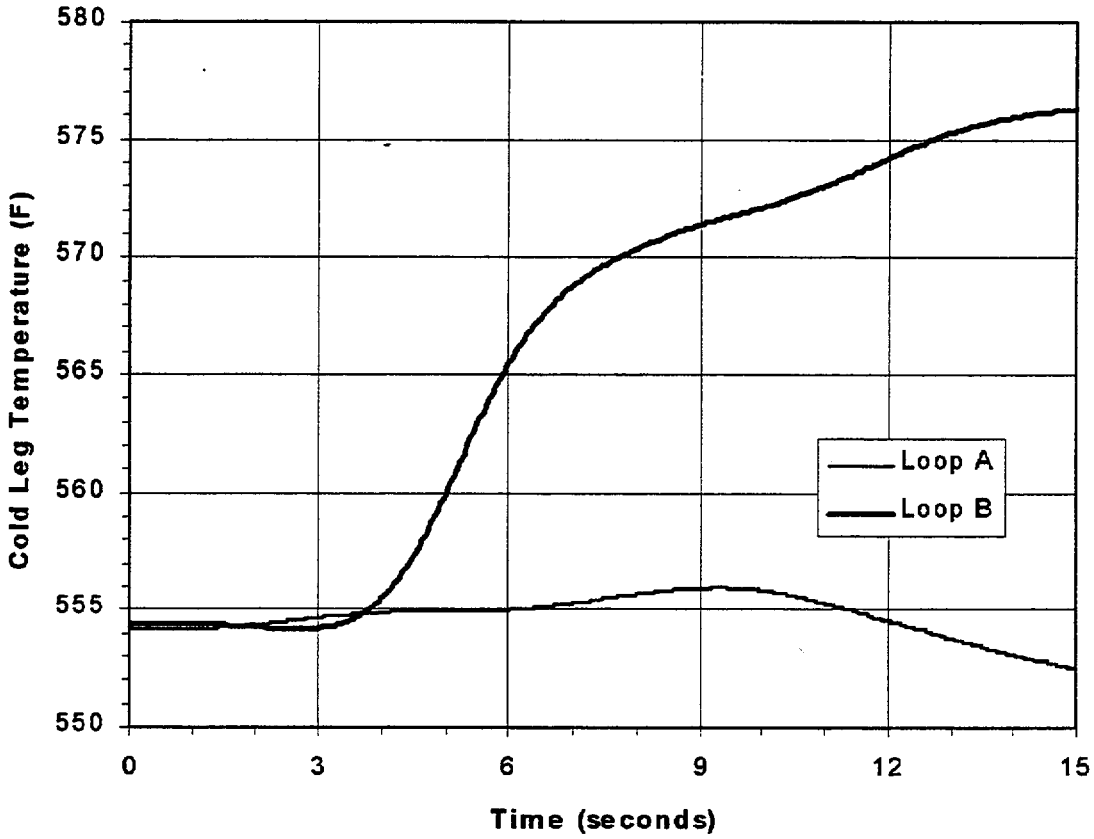
9 Figure 15-114.
9 Rod Withdrawal at Power Accident - Core Cooling Capability Analysis DNBR



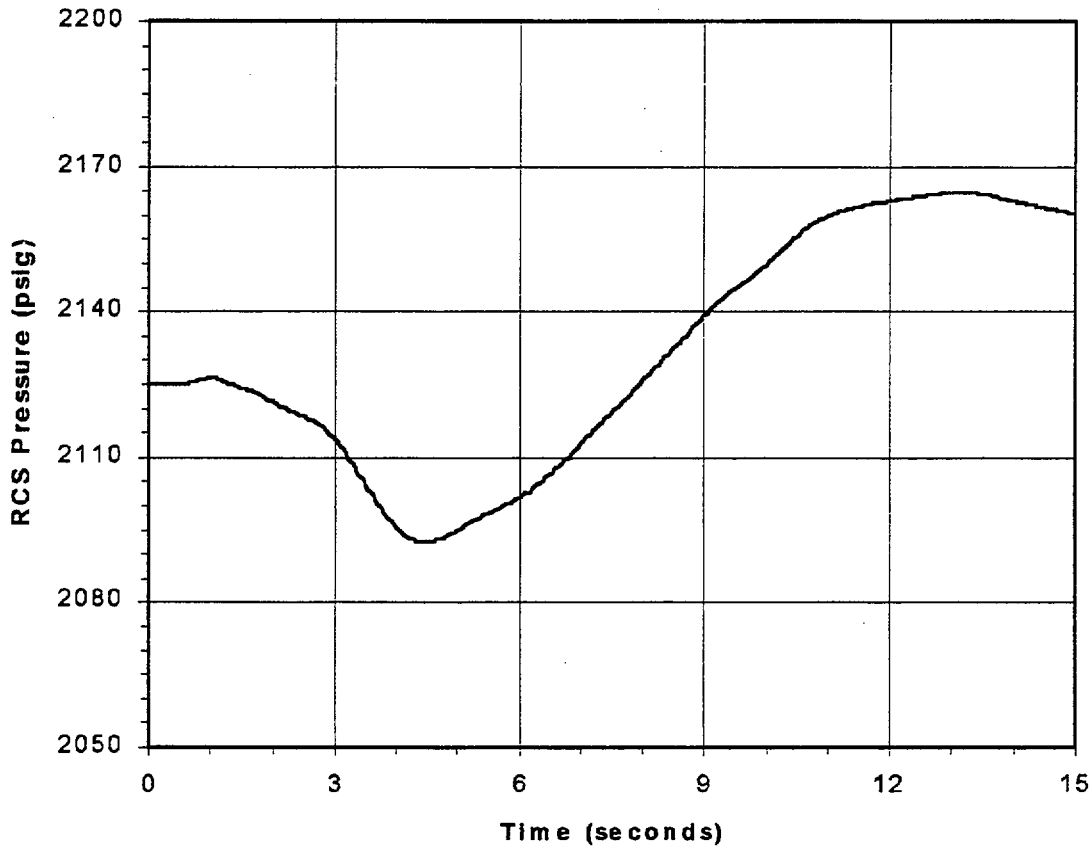
9 Figure 15-115.
9 Cold Water Accident - Core Average Temperature



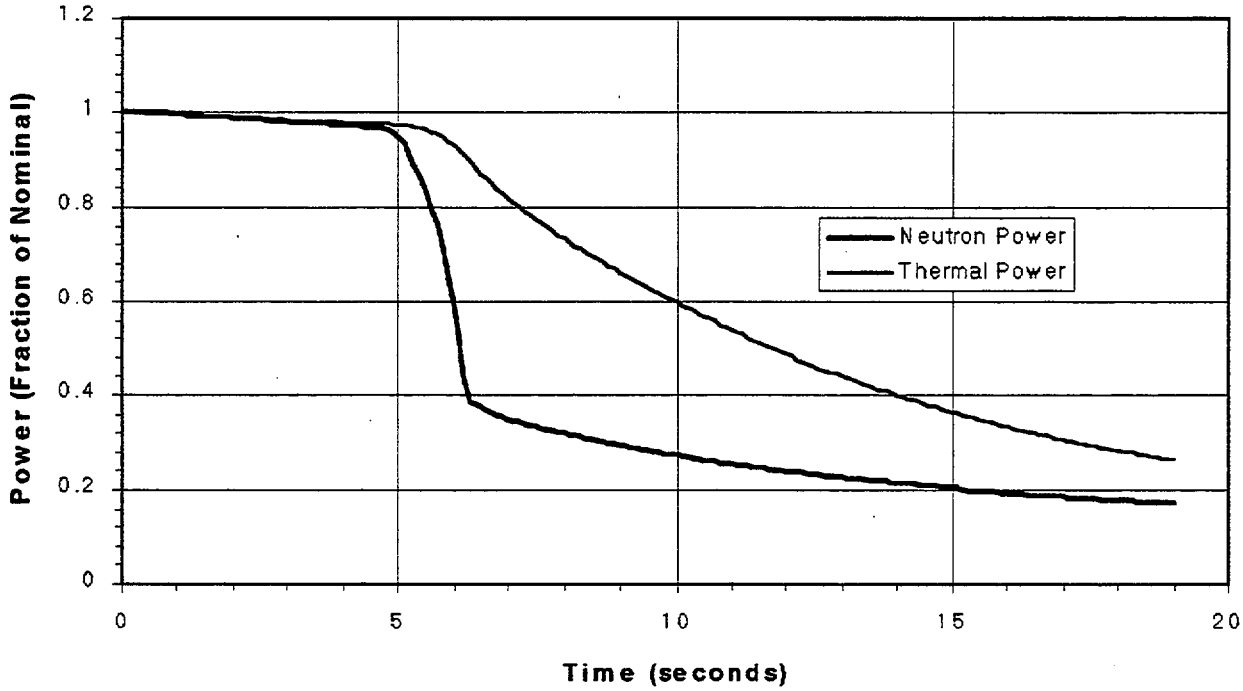
9 Figure 15-116.
9 Cold Water Accident - Power



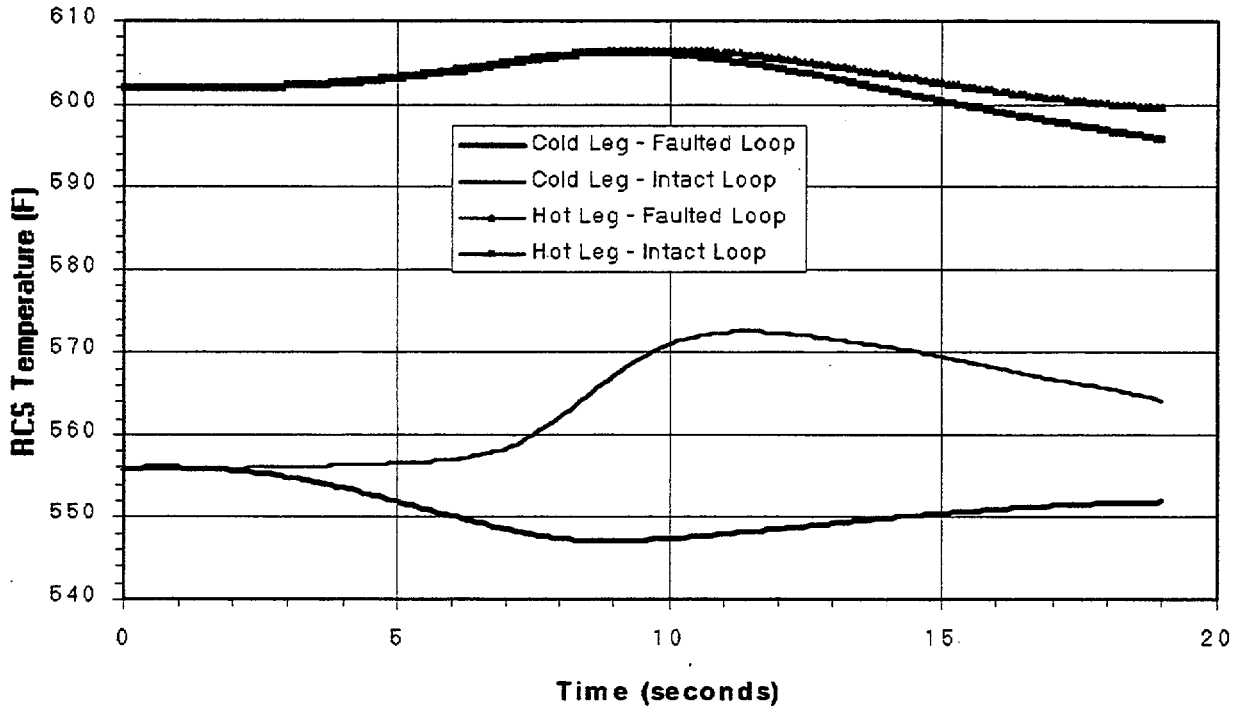
9 Figure 15-117.
9 Cold Water Accident - Cold Leg Temperature



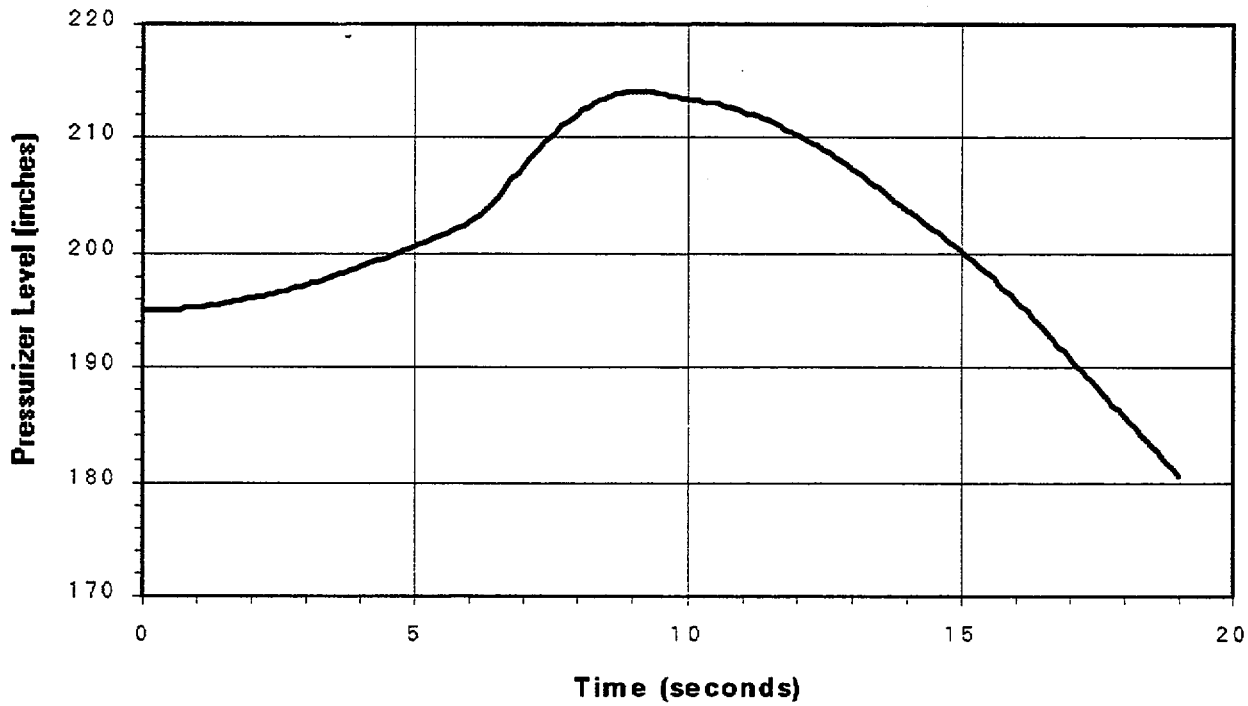
9 Figure 15-118.
9 Cold Water Accident - RCS Pressure



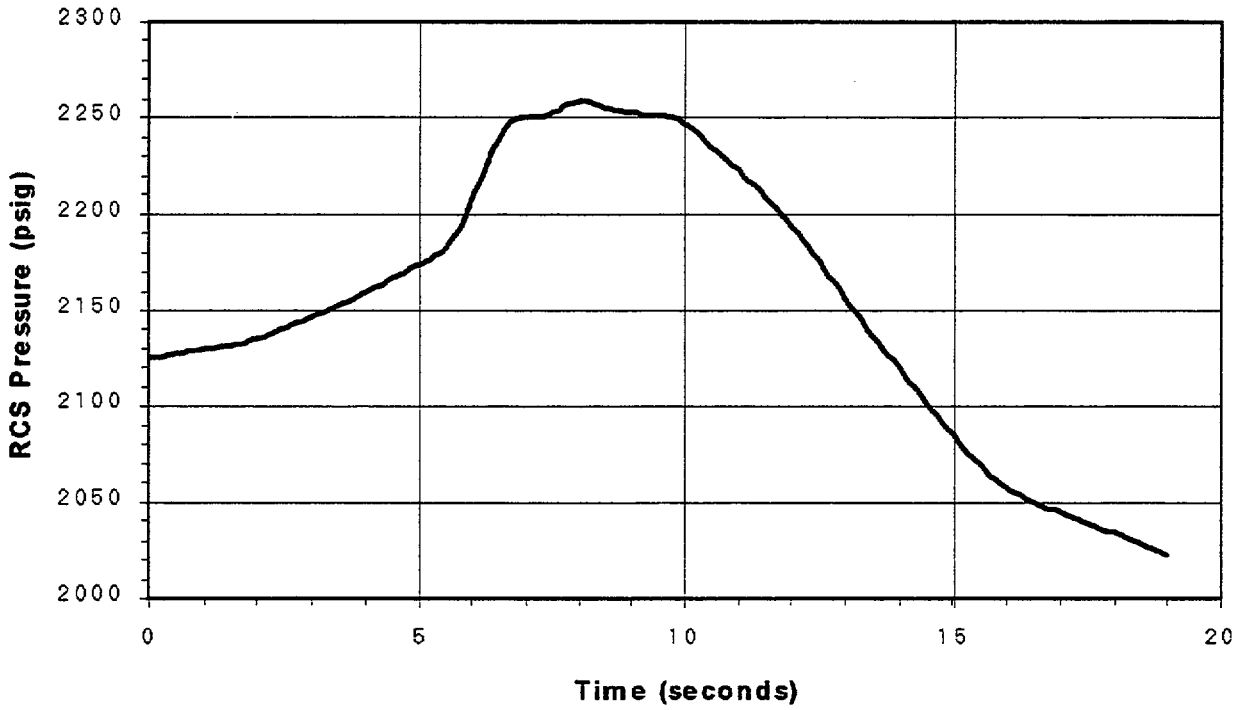
9 Figure 15-119.
9 Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis -
9 Power



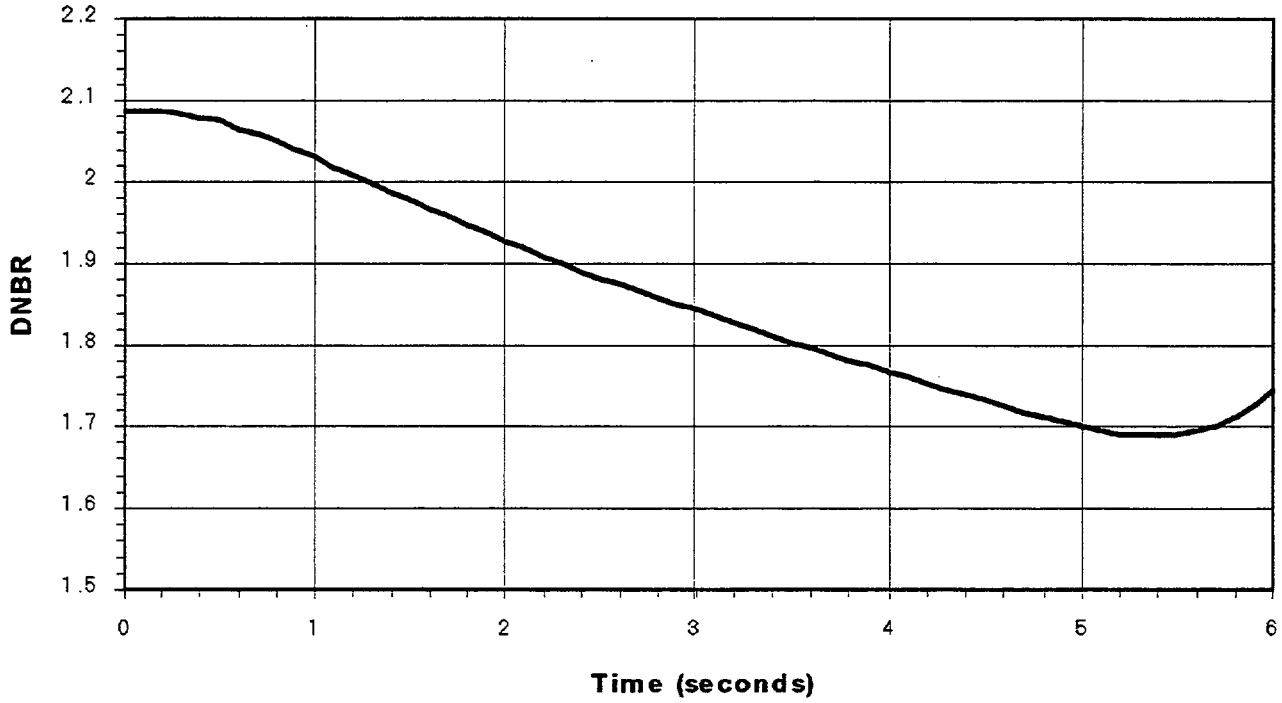
9 **Figure 15-120.**
9 **Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis - RCS**
9 **Temperature**



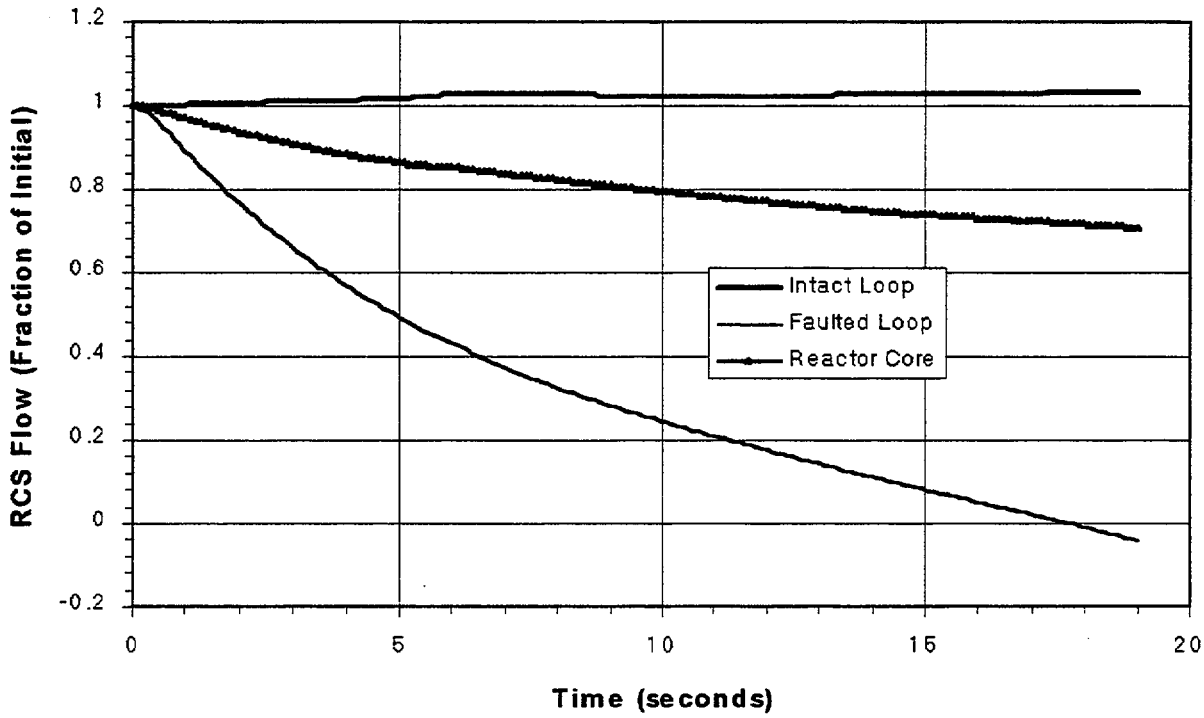
9 Figure 15-121.
9 Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis -
9 Pressurizer Level



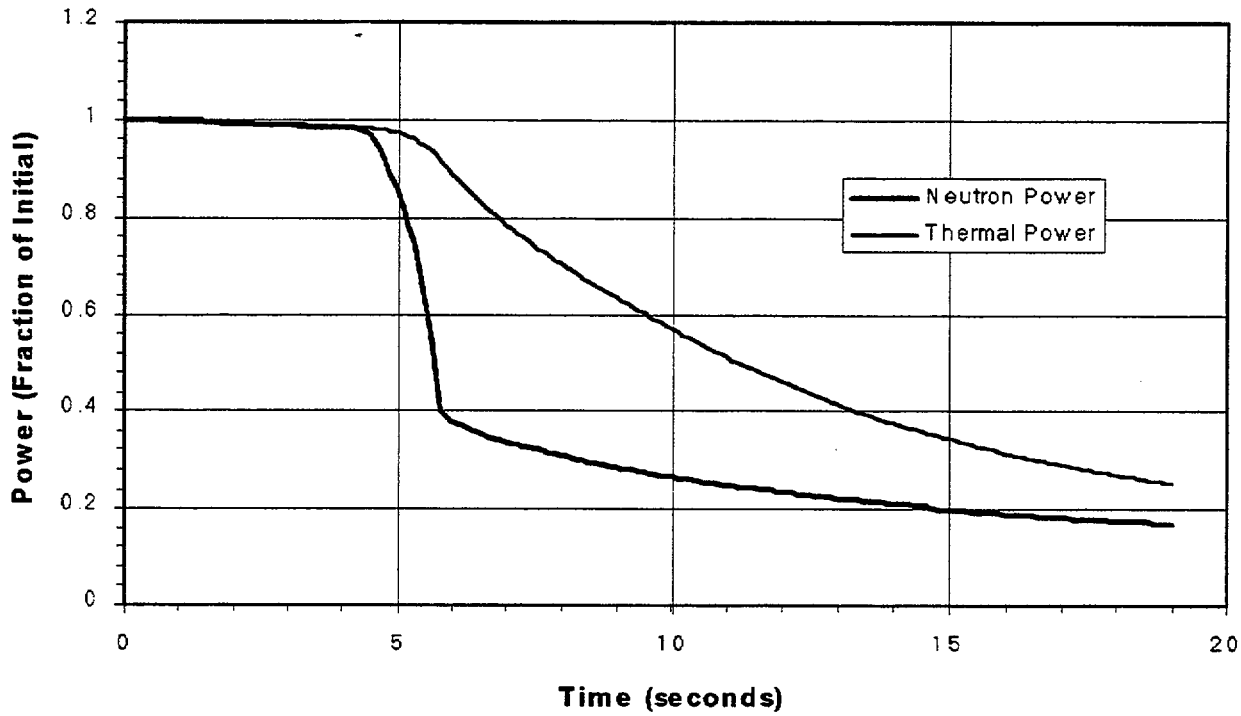
9 Figure 15-122.
9 Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis - RCS
9 Pressure



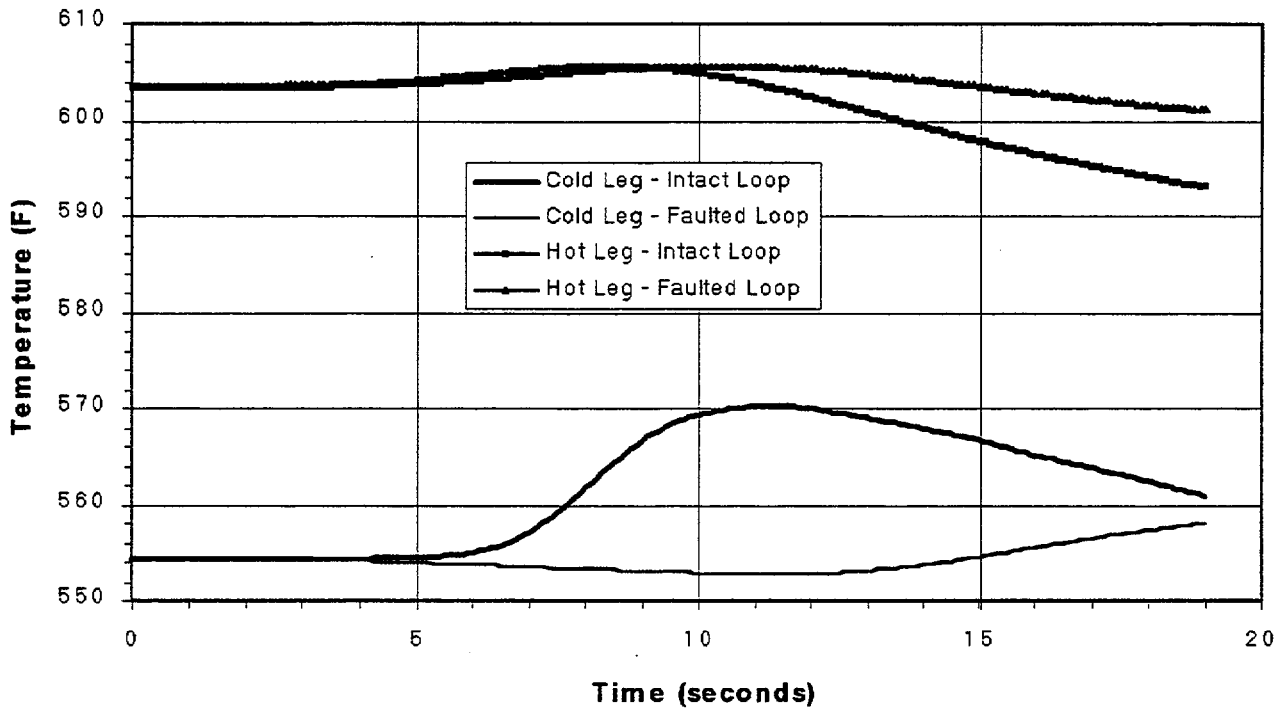
9 Figure 15-123.
9 Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis -
9 DNBR



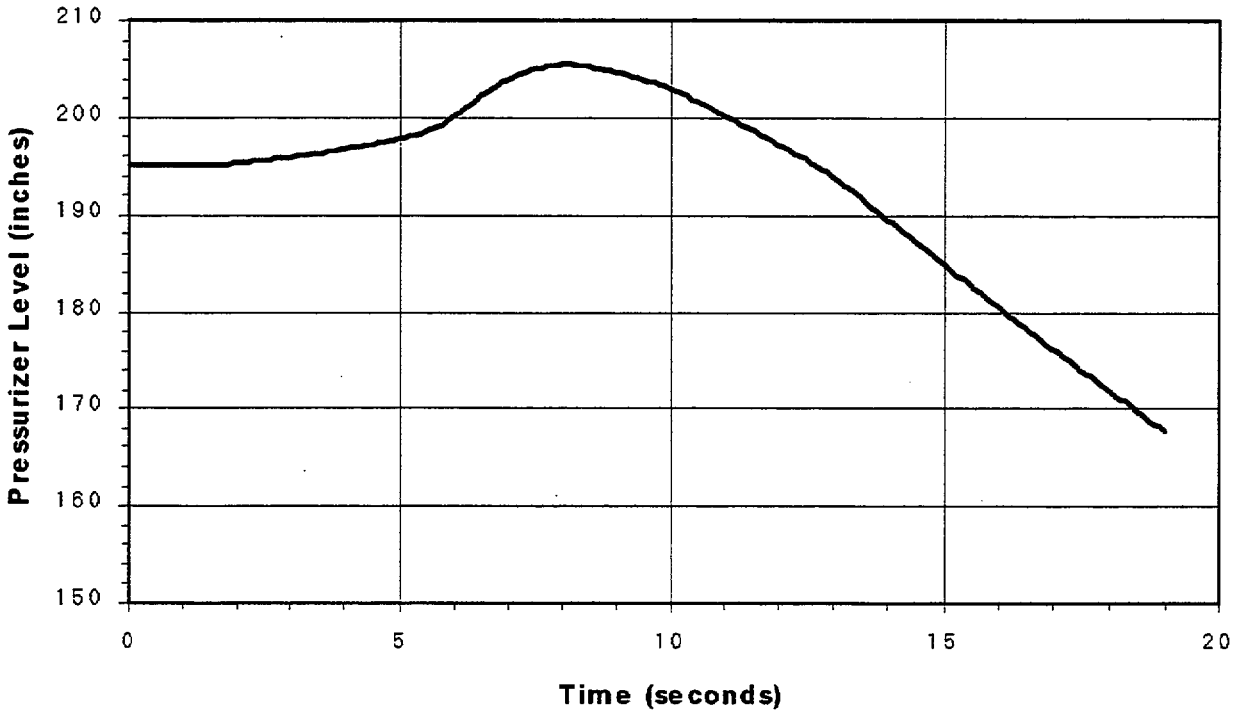
9 Figure 15-124.
9 Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis -
9 RCS Flow



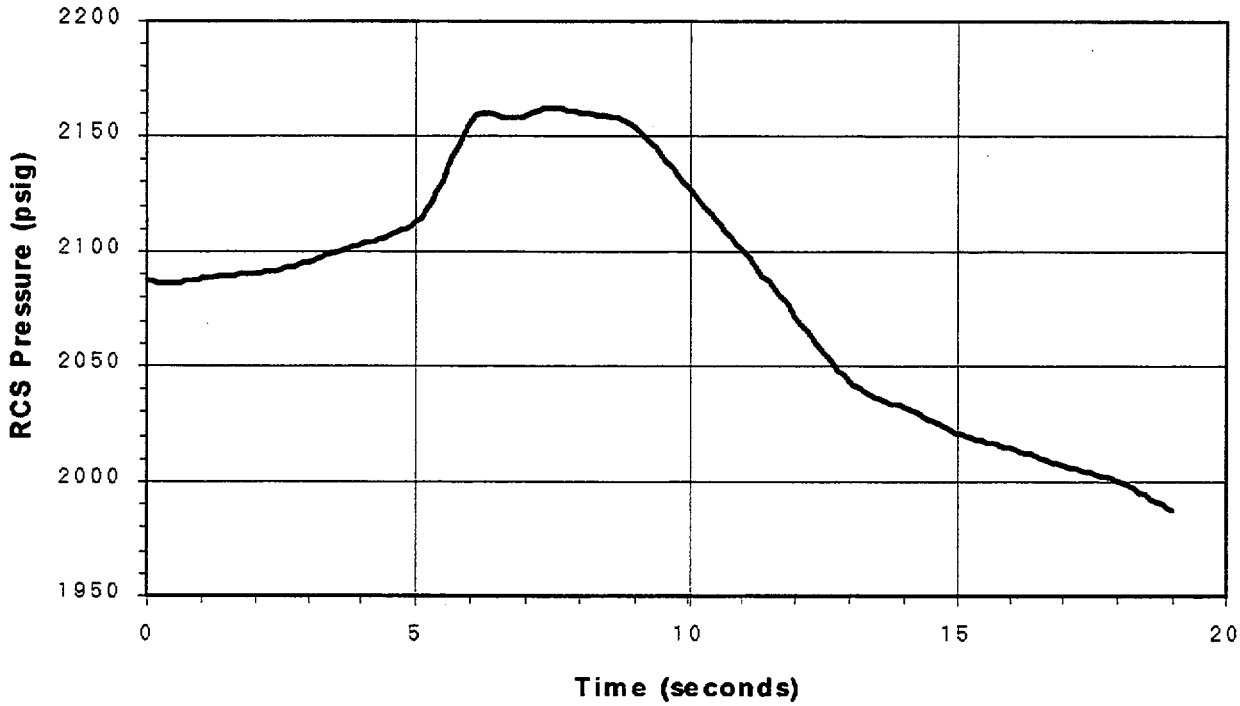
9 Figure 15-125.
9 Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis -
9 Power



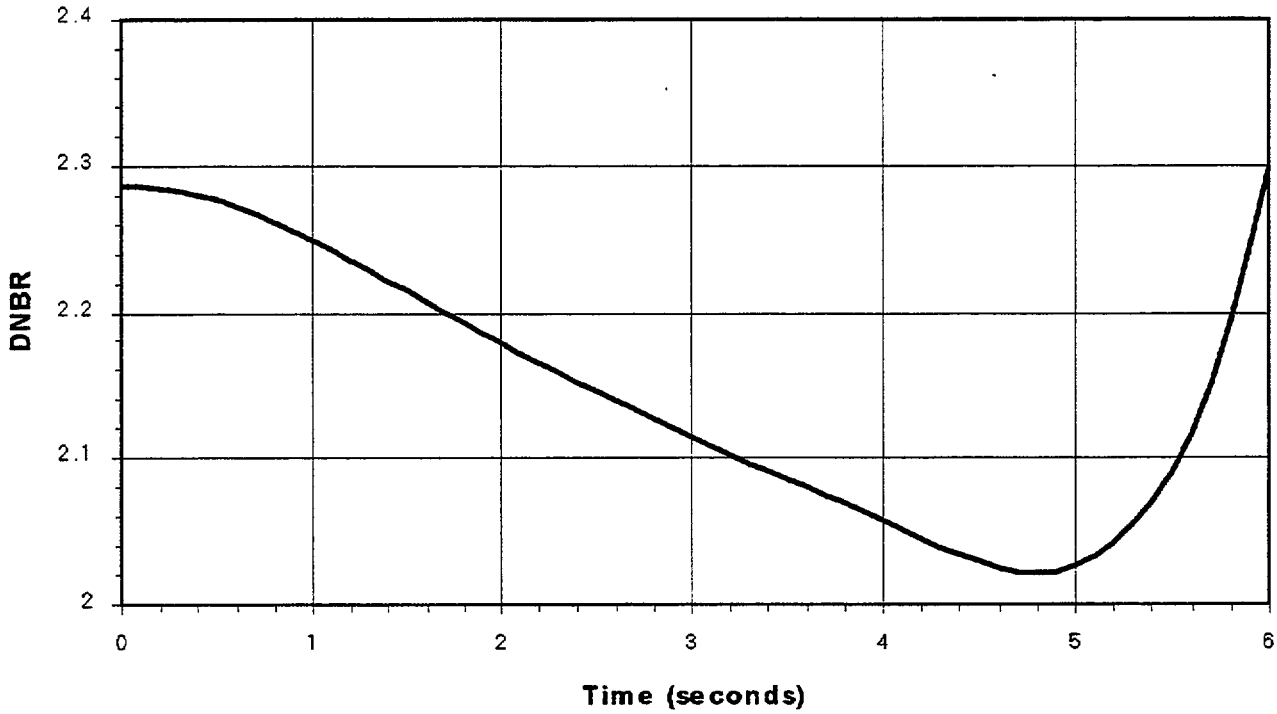
9 Figure 15-126.
9 Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis -
9 RCS Temperature



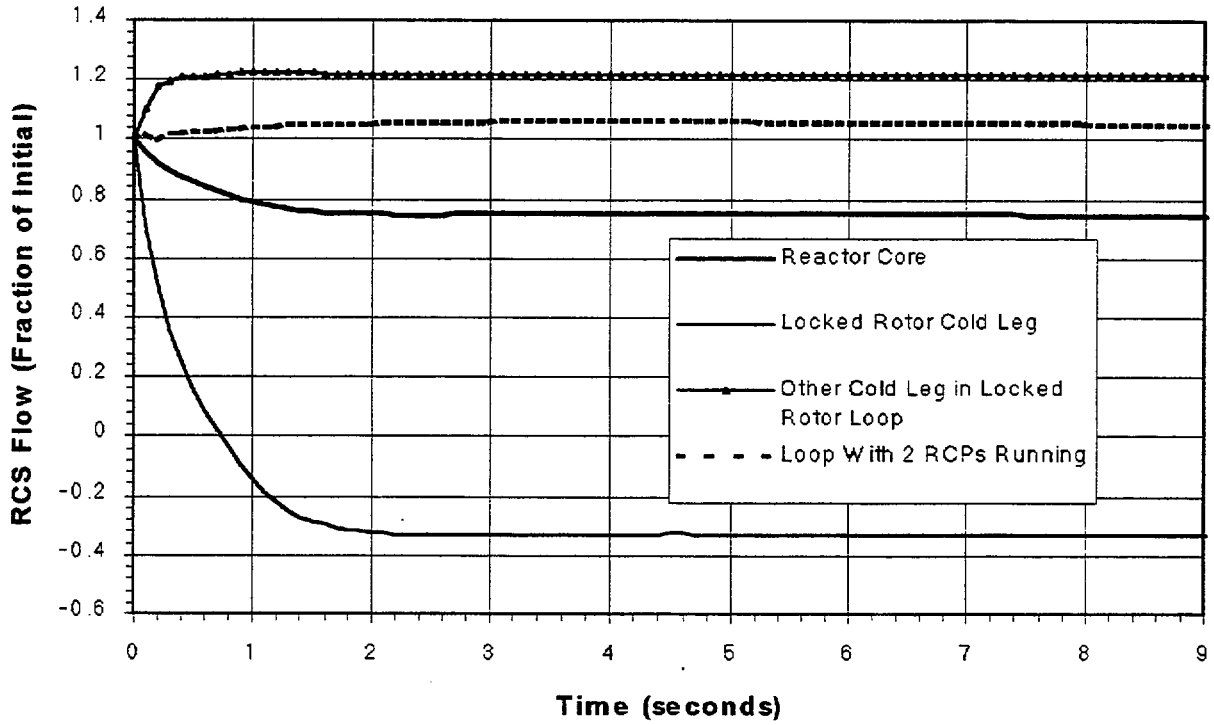
9 Figure 15-127.
9 Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis -
9 Pressurizer Level



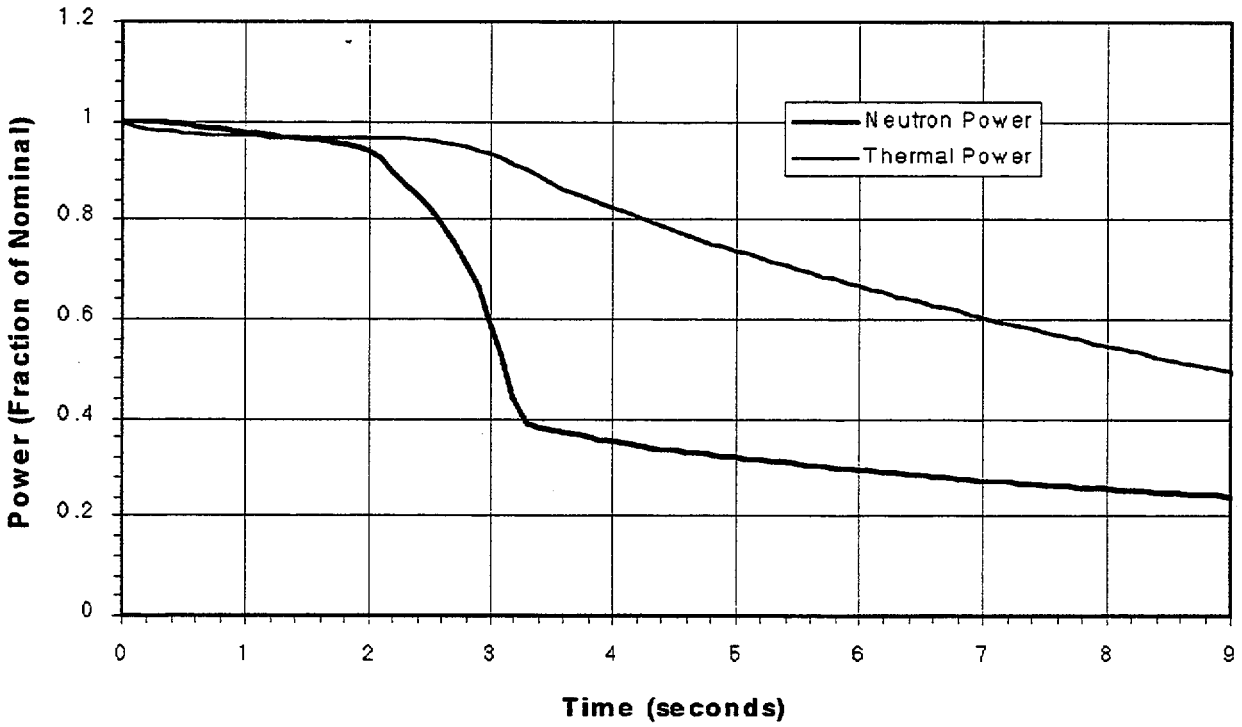
9 Figure 15-128.
9 Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis -
9 RCS Pressure



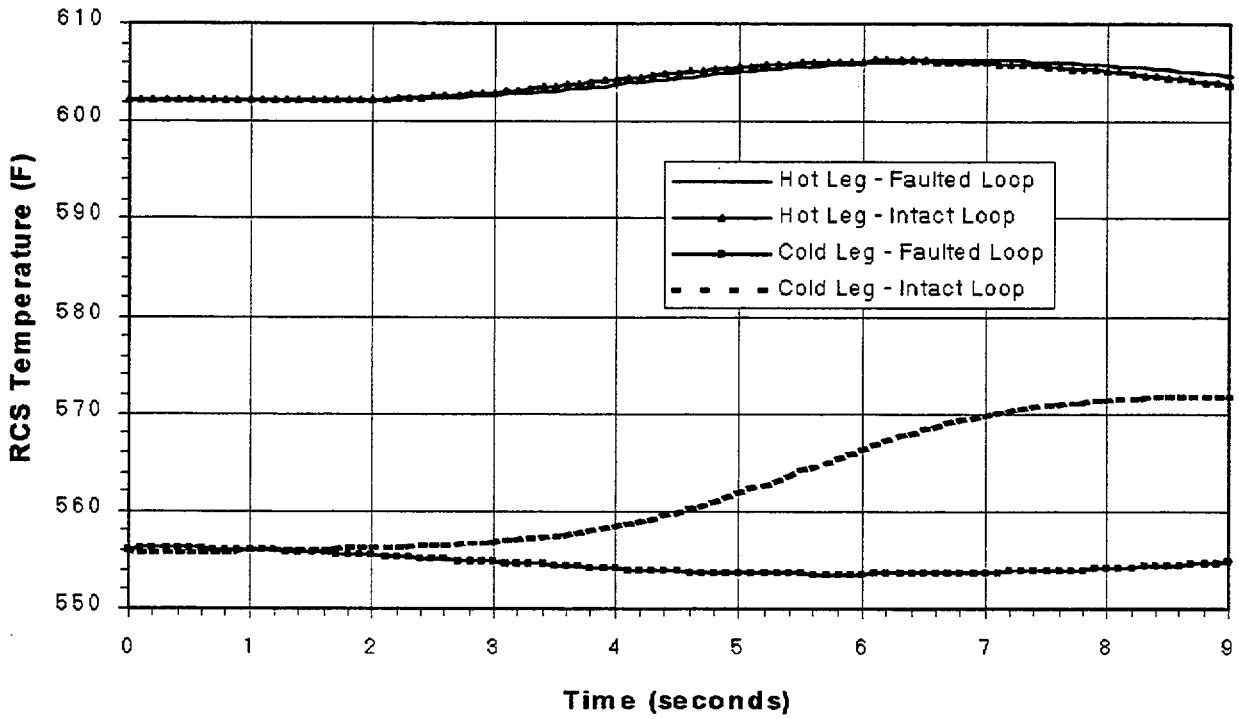
9 Figure 15-129.
9 Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis -
9 DNBR



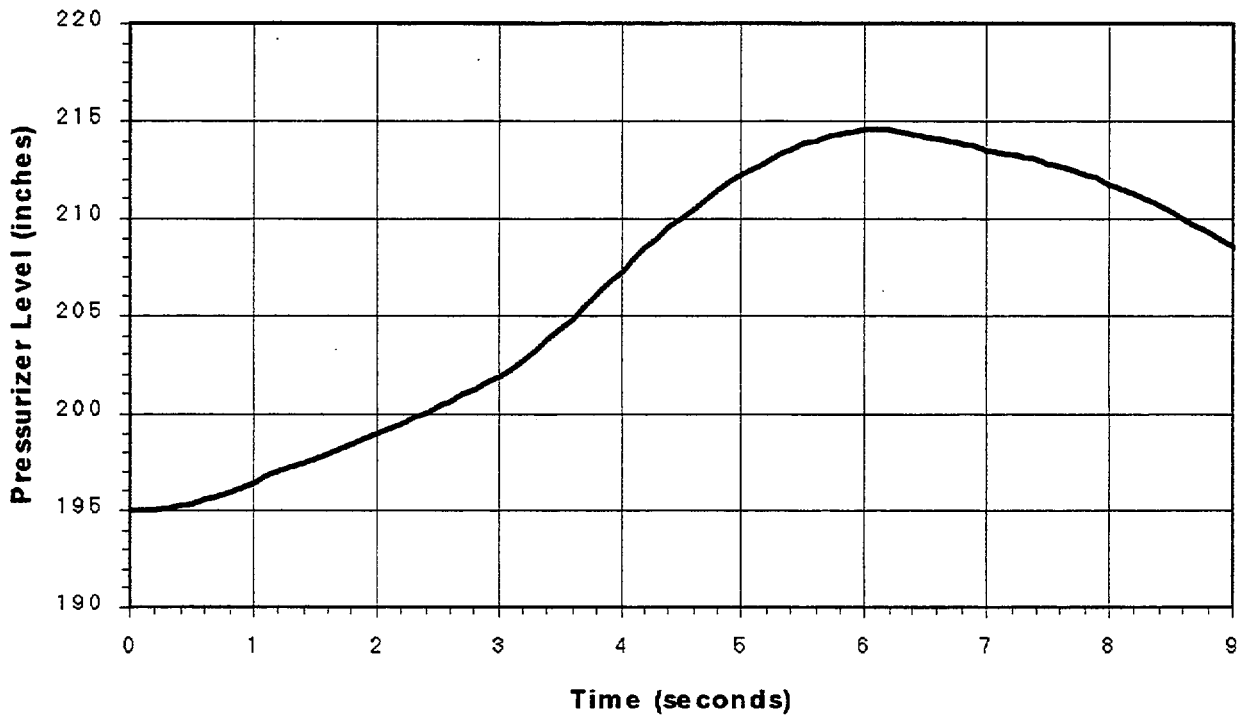
9 **Figure 15-130.**
9 **Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - RCS Flow**



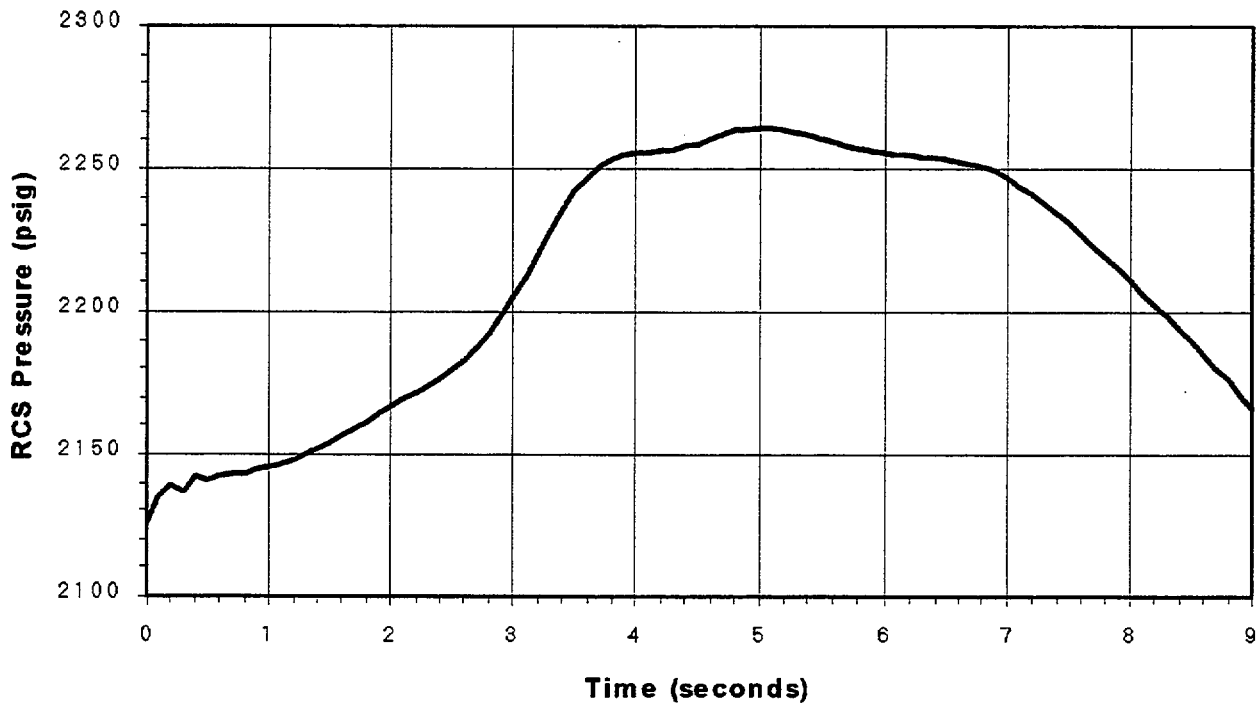
9 Figure 15-131.
9 Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - Power



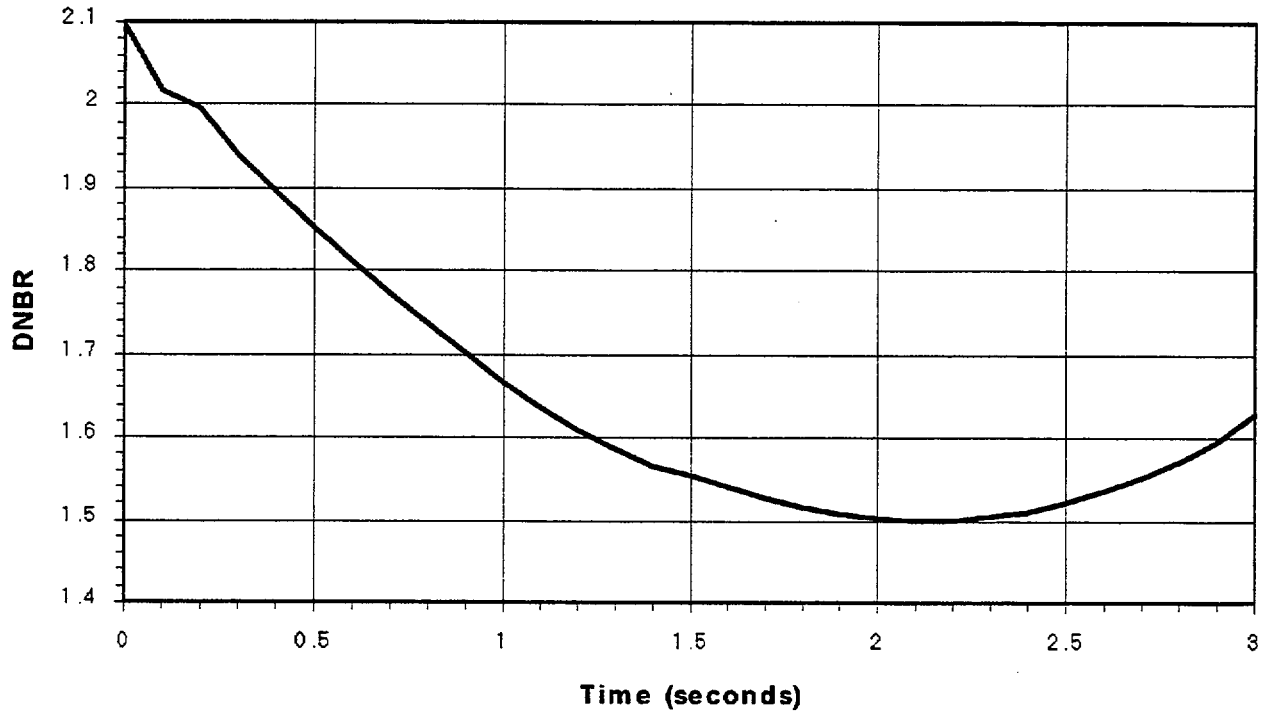
9 Figure 15-132.
9 Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - RCS
9 Temperature



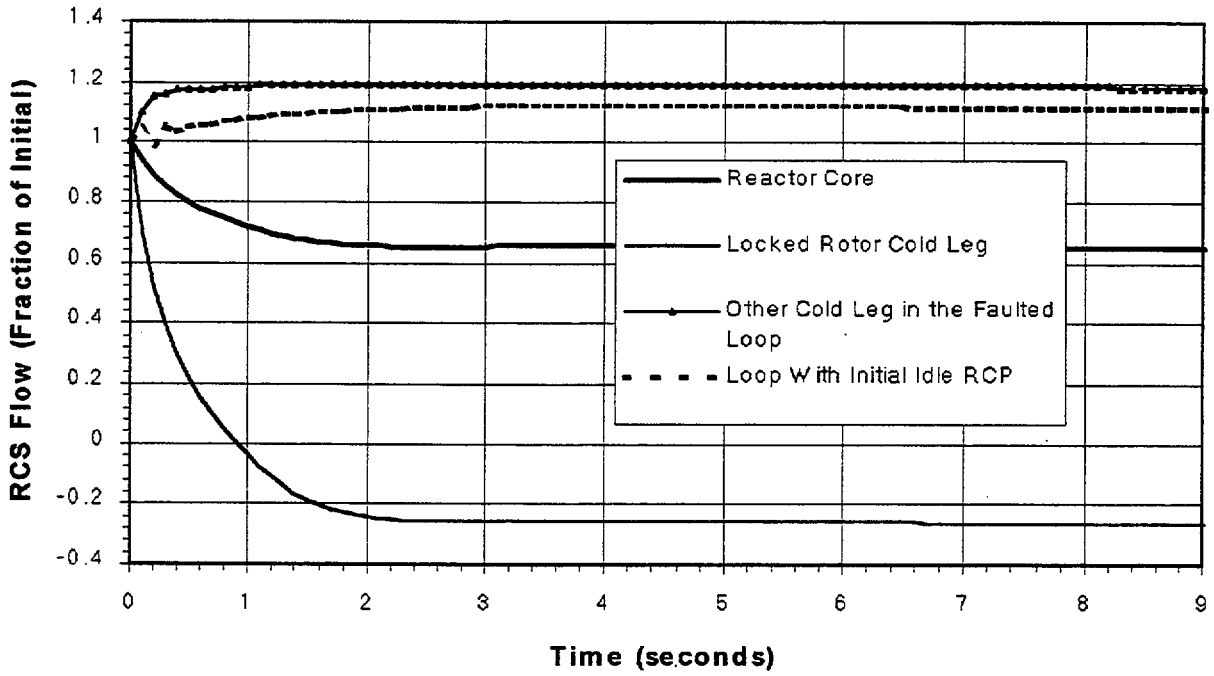
9 Figure 15-133.
9 Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - Pressurizer
9 Level



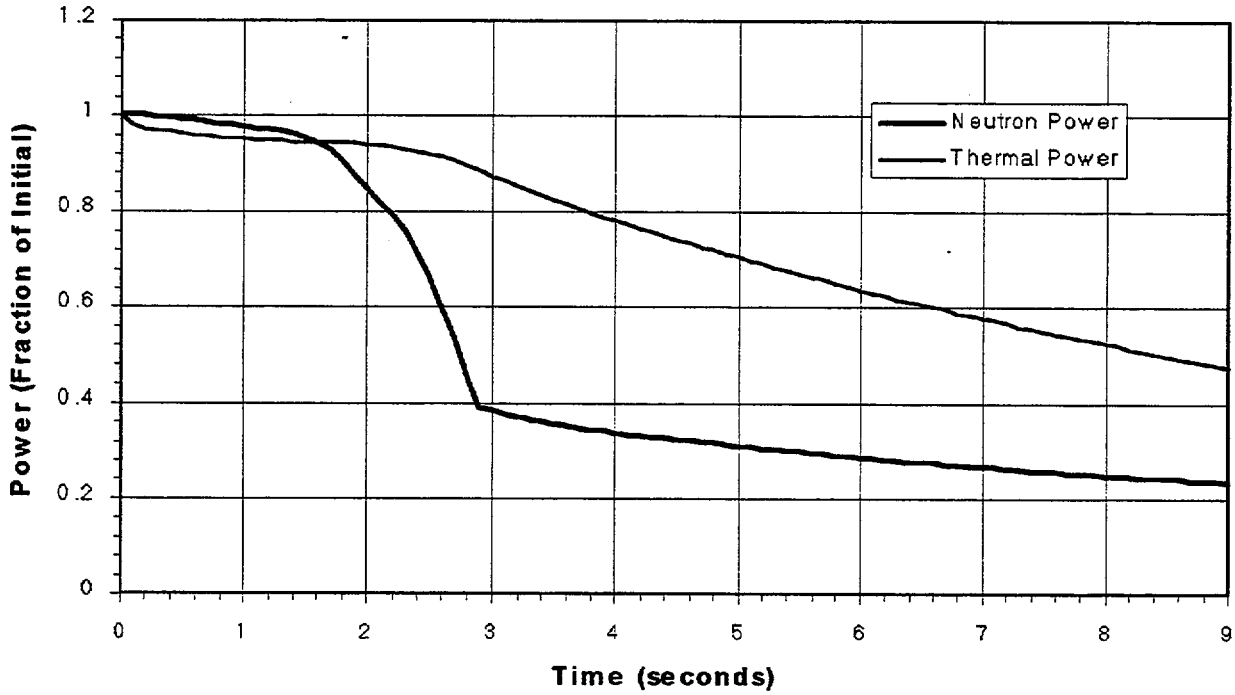
9 Figure 15-134.
9 Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - RCS
9 Pressure



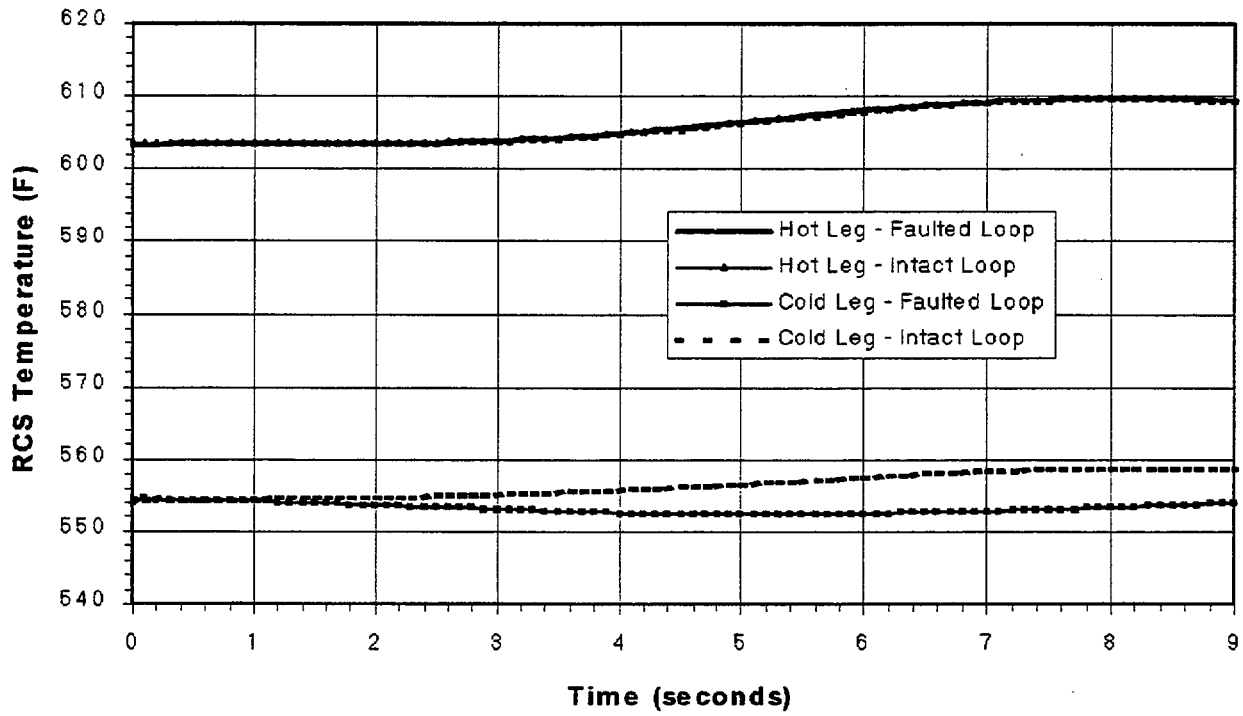
9 Figure 15-135.
9 Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - DNBR



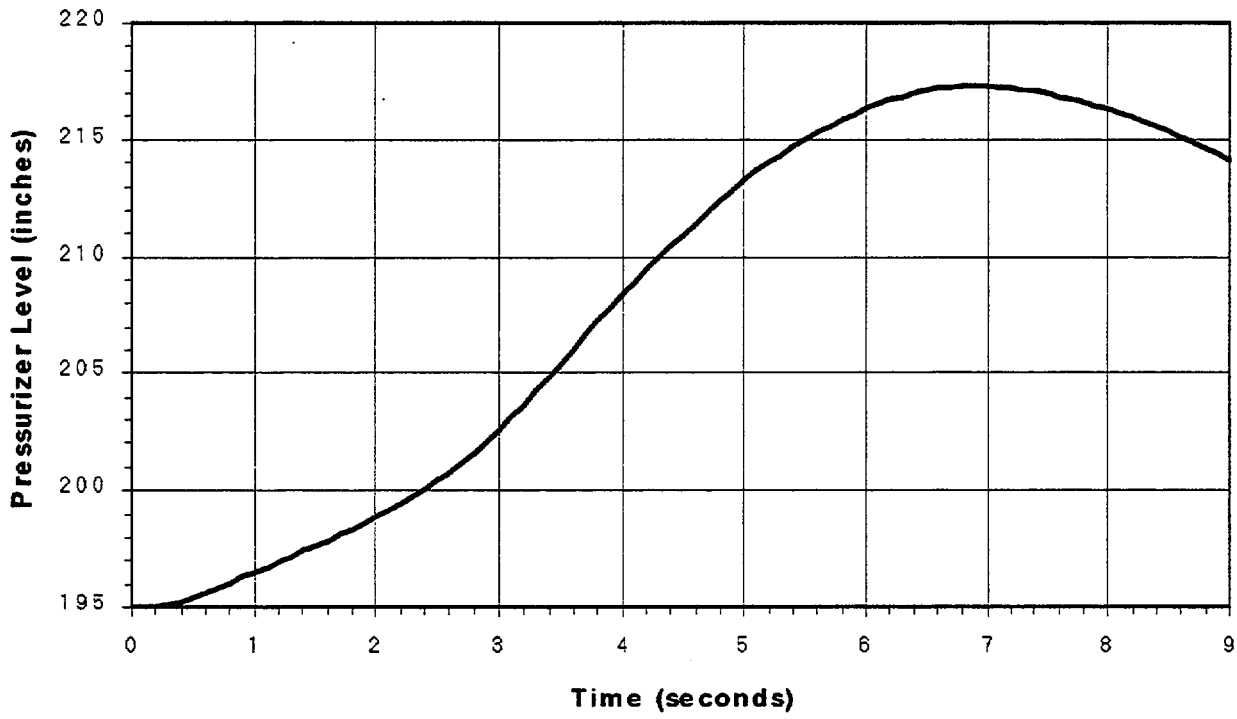
9 Figure 15-136.
9 Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - RCS Flow



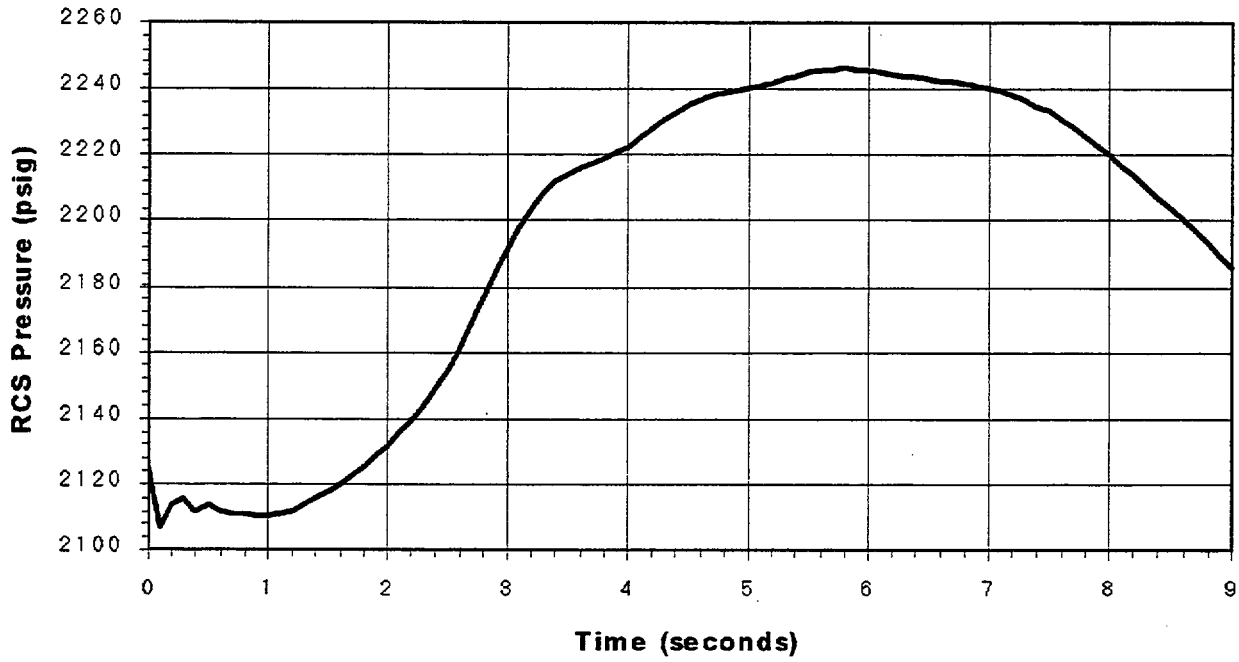
9 Figure 15-137.
9 Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - Power



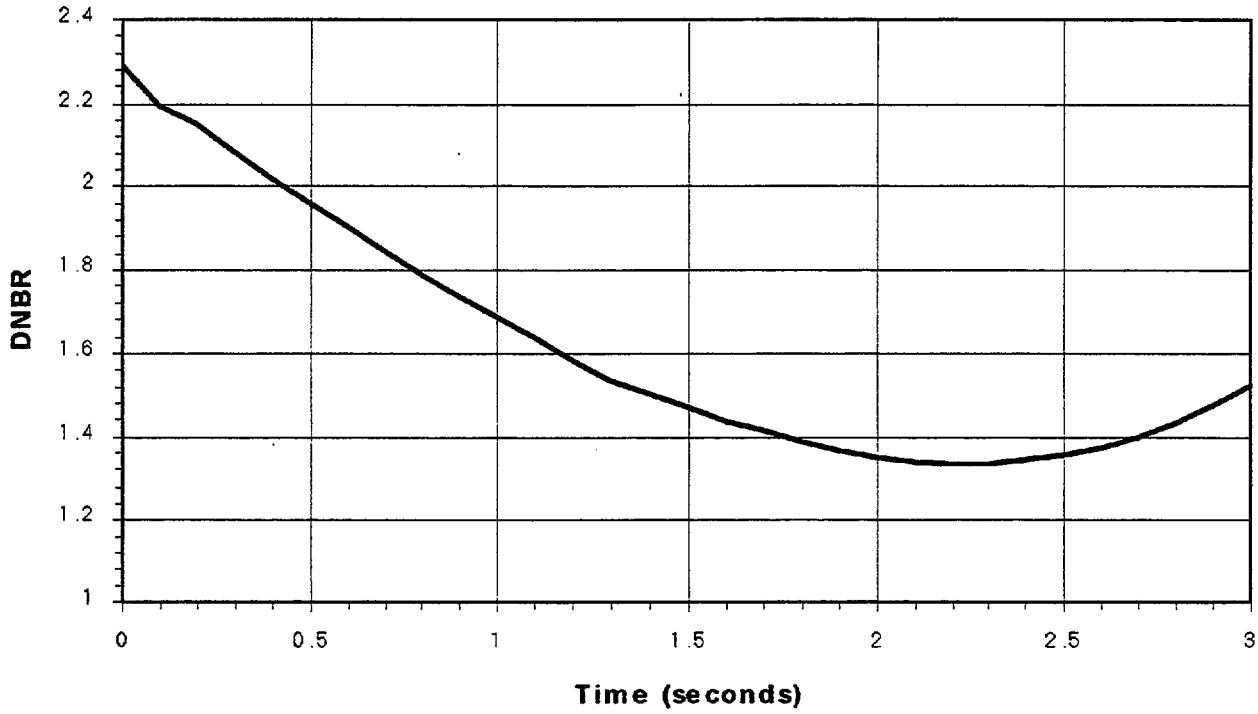
9 **Figure 15-138.**
9 **Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - RCS**
9 **Temperatures**



9 Figure 15-139.
9 Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - Pressurizer
9 Level



9 Figure 15-140.
9 Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - RCS
9 Pressure

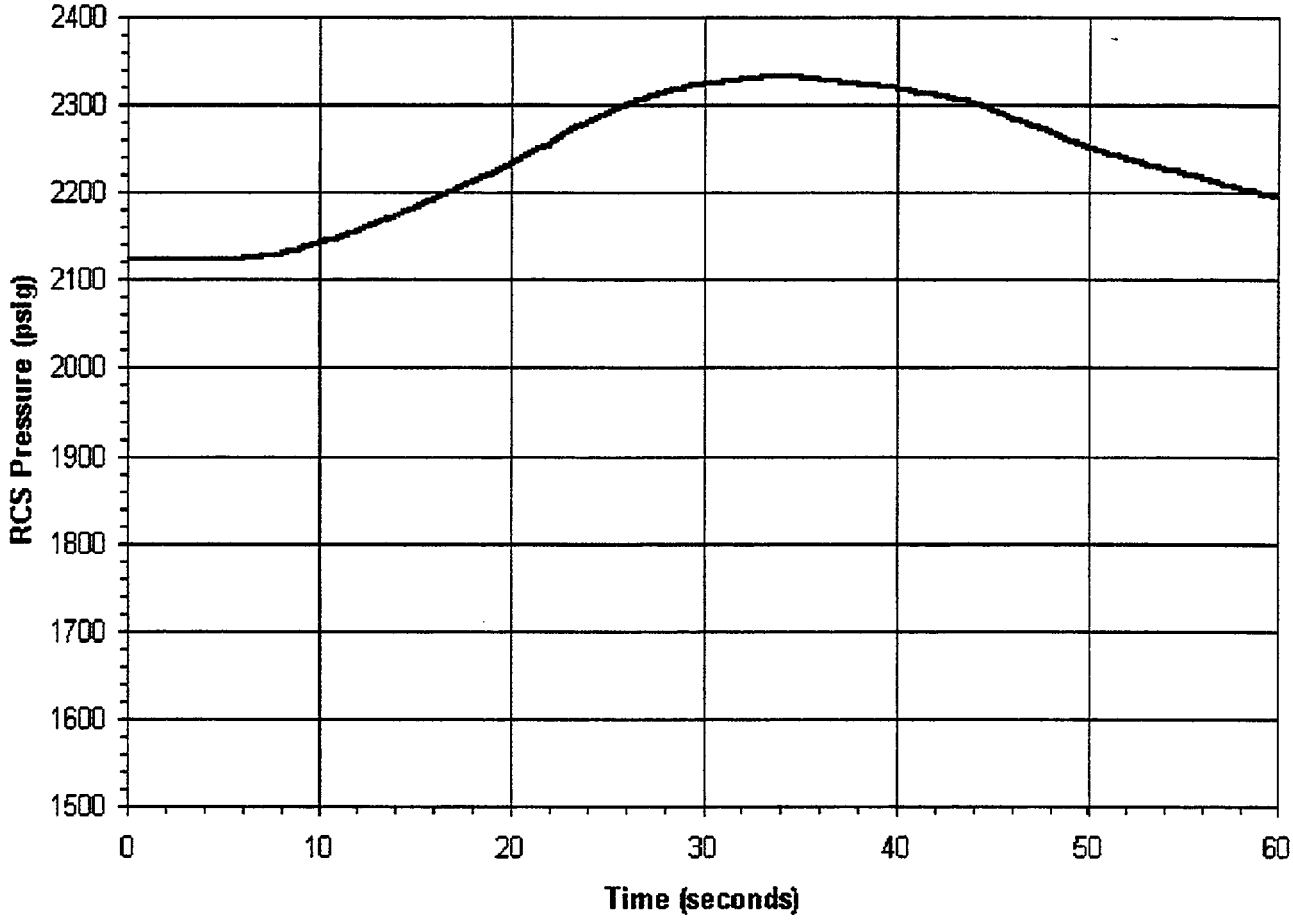


9 Figure 15-141.
9 Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - DNBR

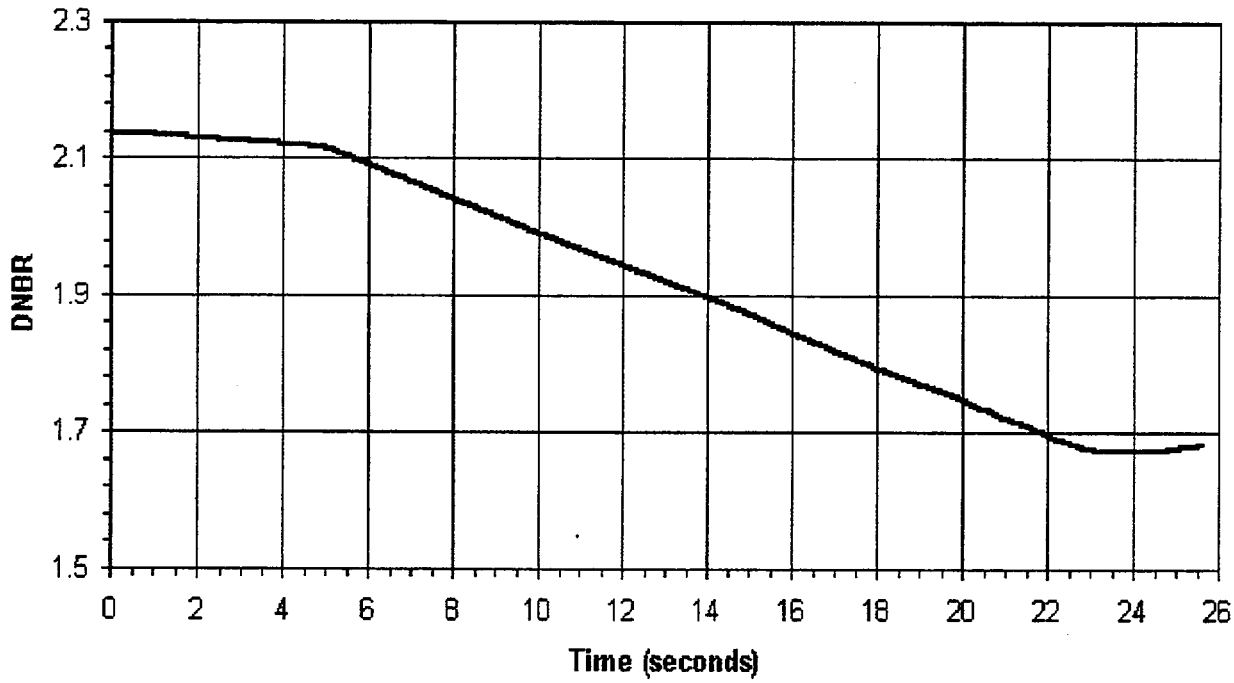
Intentionally Blank

9
9

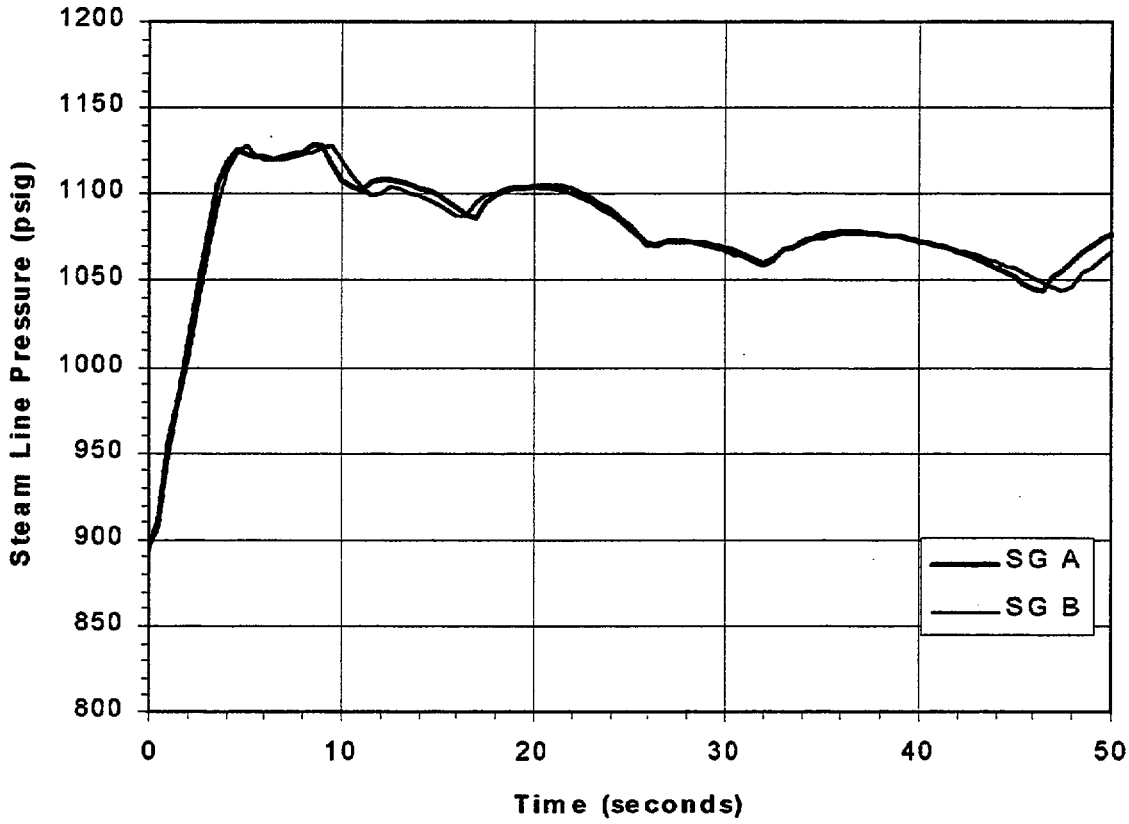
Figure 15-142.
Intentionally Blank



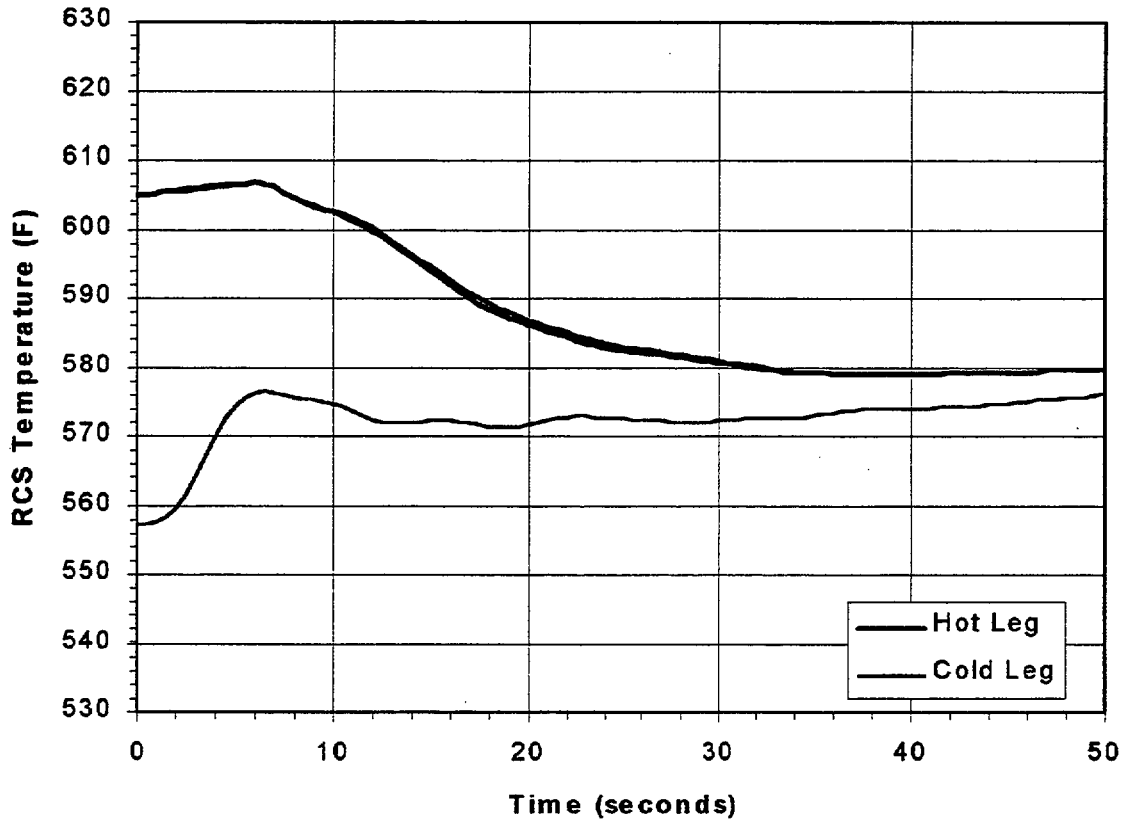
9 Figure 15-143.
9 Control Rod Misalignment Accidents - Dropped Rod - RCS Pressure



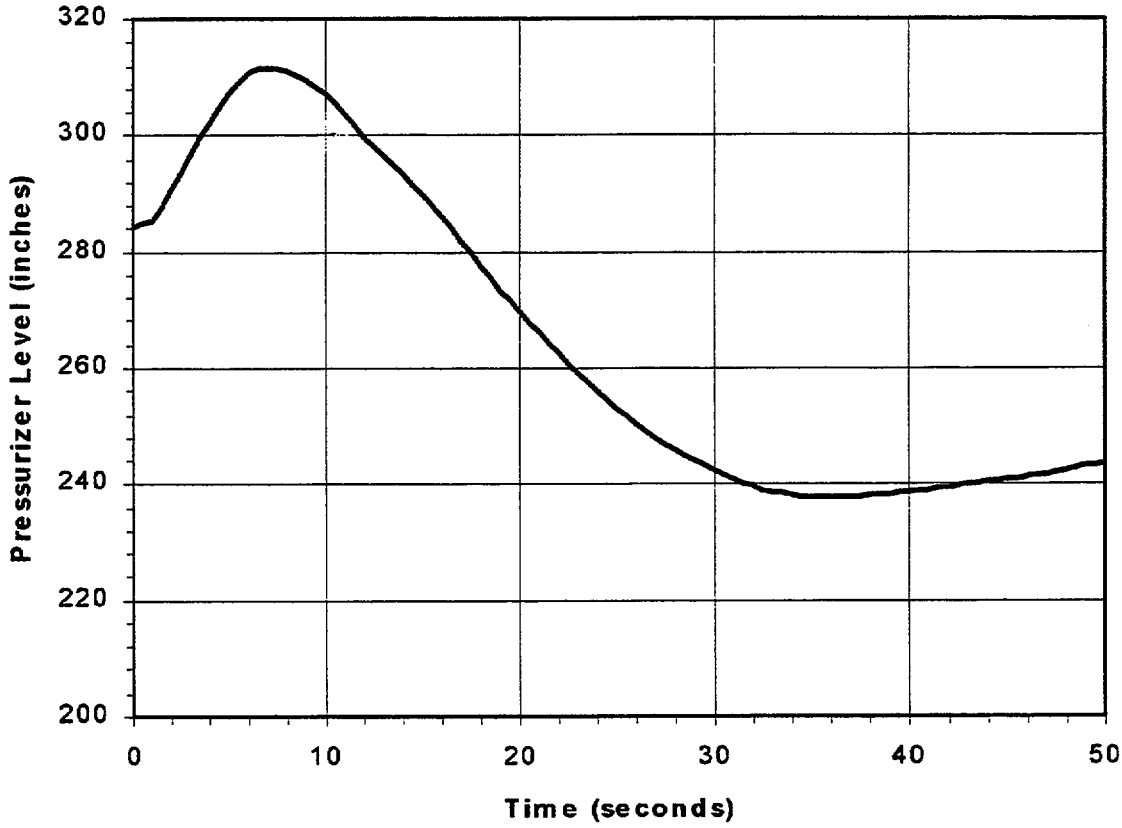
9 Figure 15-144.
9 Control Rod Misalignment Accidents - Dropped Rod - DNBR



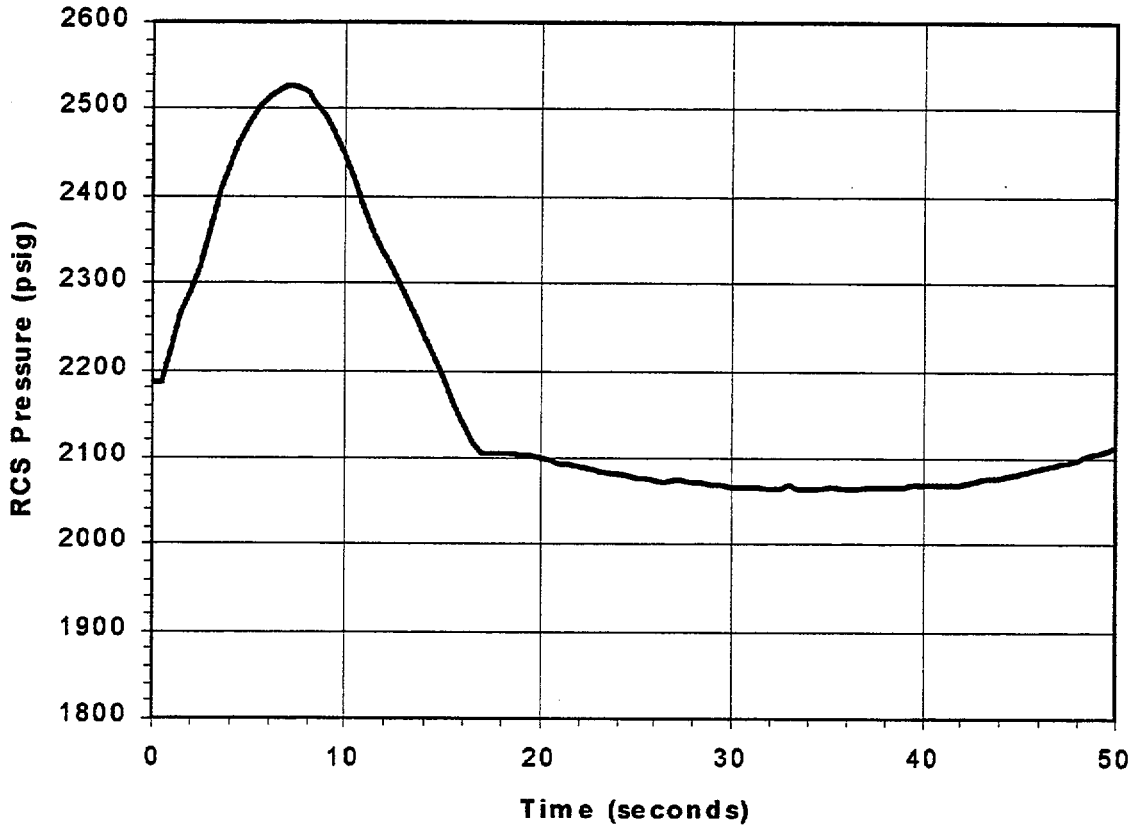
9 Figure 15-145.
9 Turbine Trip Accident - Steam Line Pressure



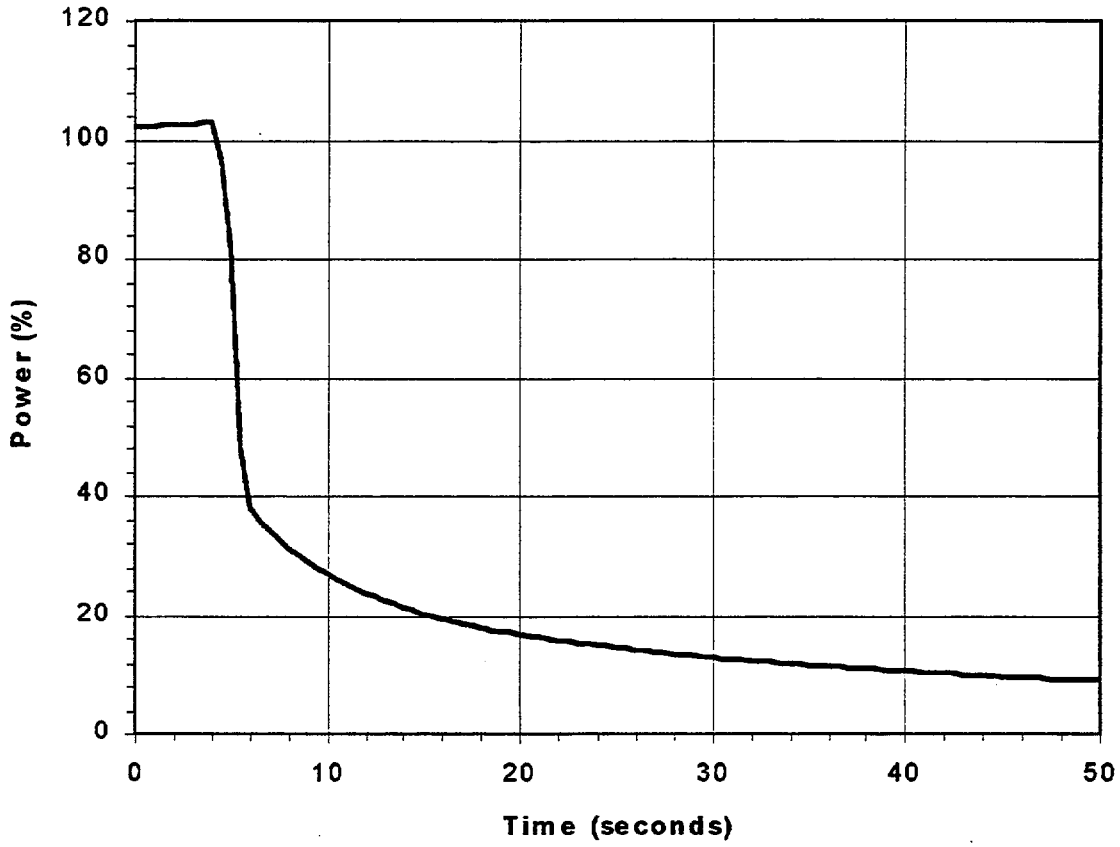
9 Figure 15-146.
9 Turbine Trip Accident - RCS Temperatures



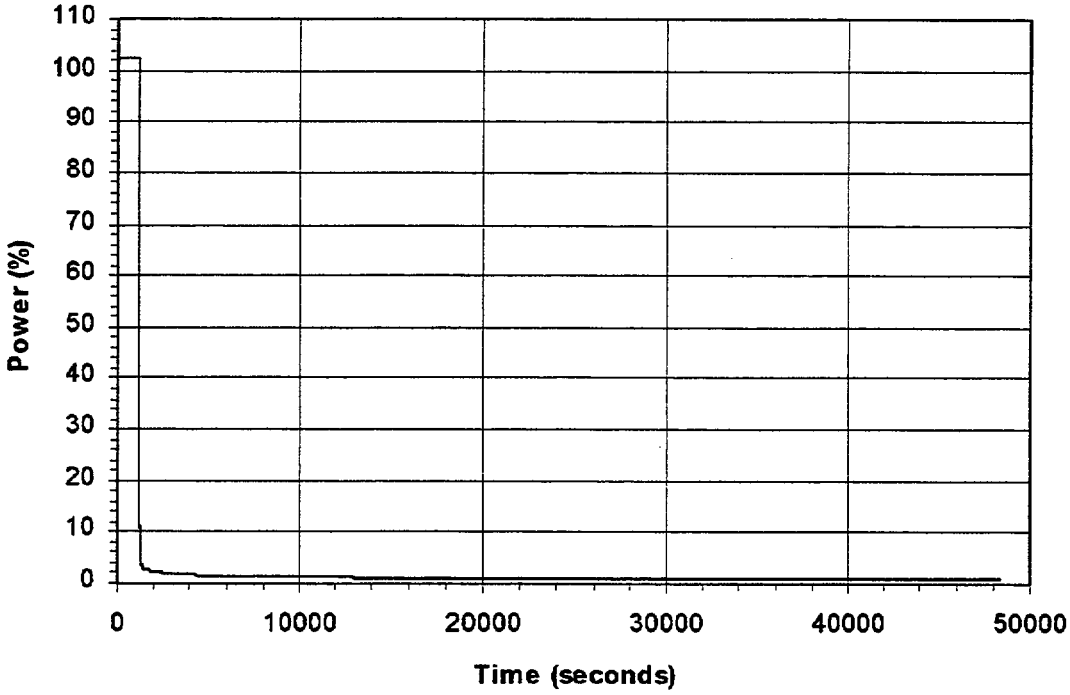
9 Figure 15-147.
9 Turbine Trip Accident - Pressurizer Level



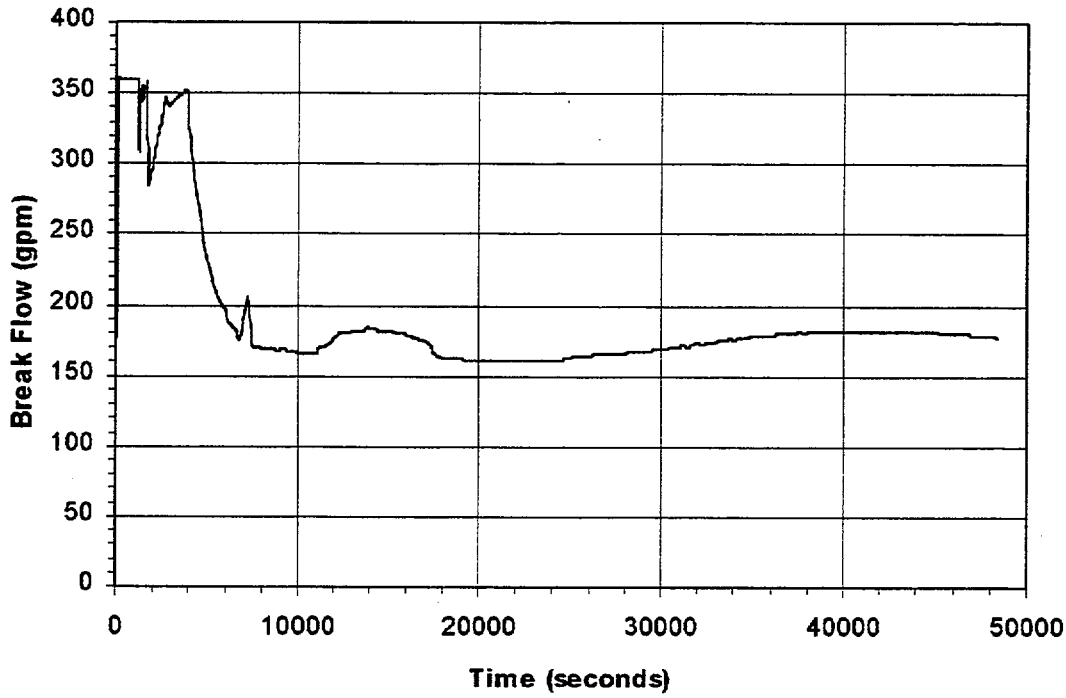
9 Figure 15-148.
9 Turbine Trip Accident - RCS Pressure



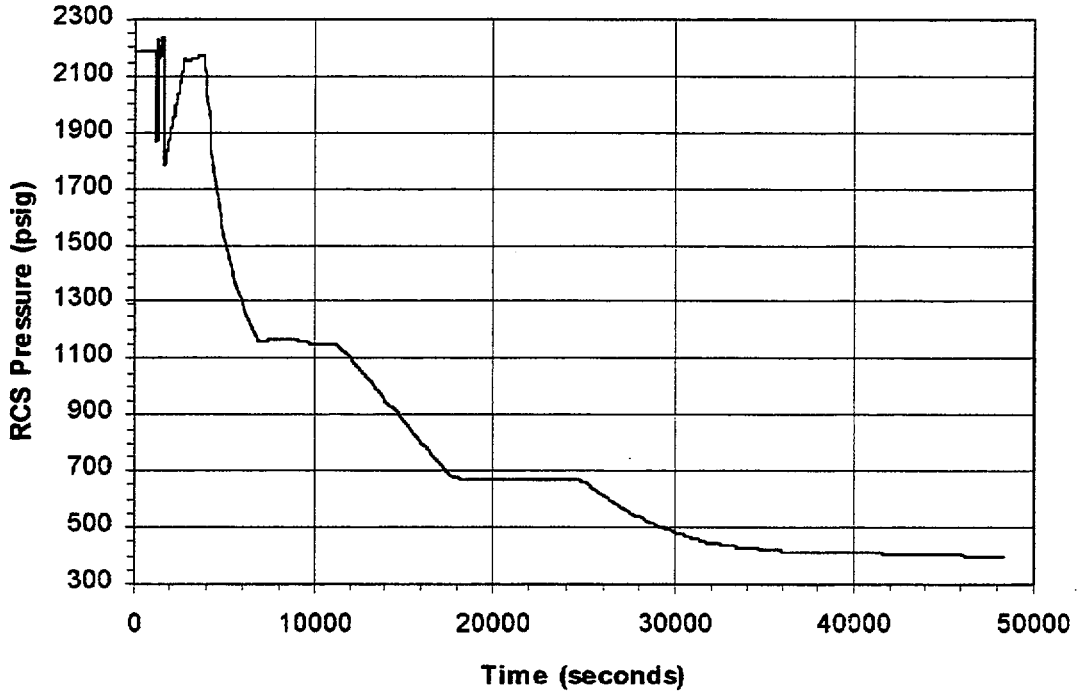
9 Figure 15-149.
9 Turbine Trip Accident - Power



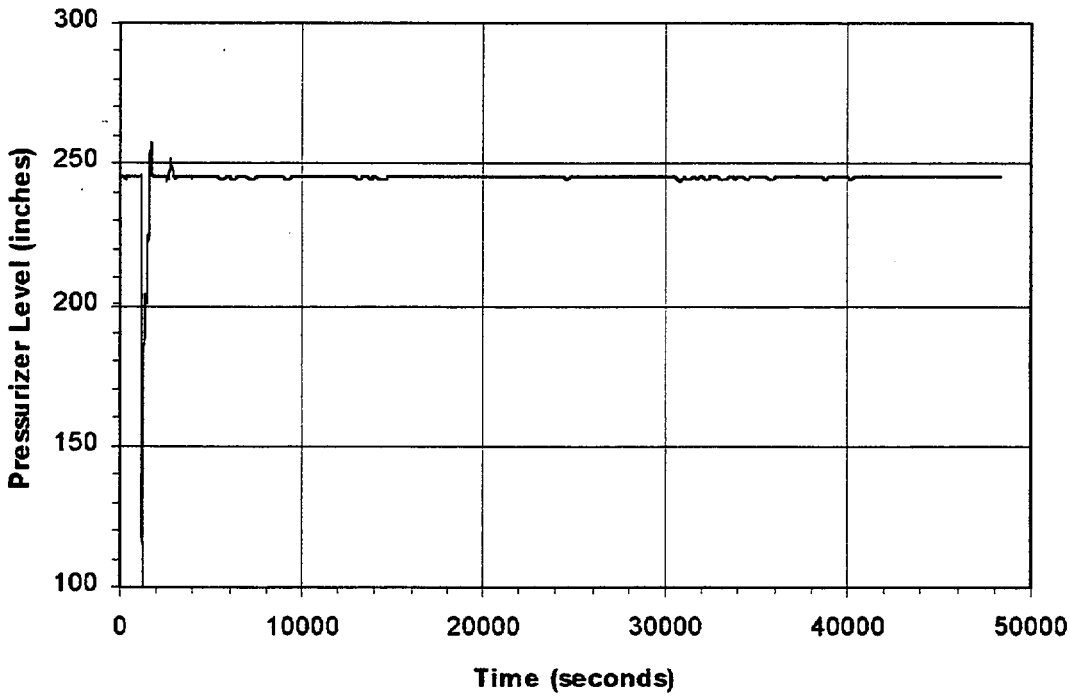
9 Figure 15-150.
9 Steam Generator Tube Rupture - Power



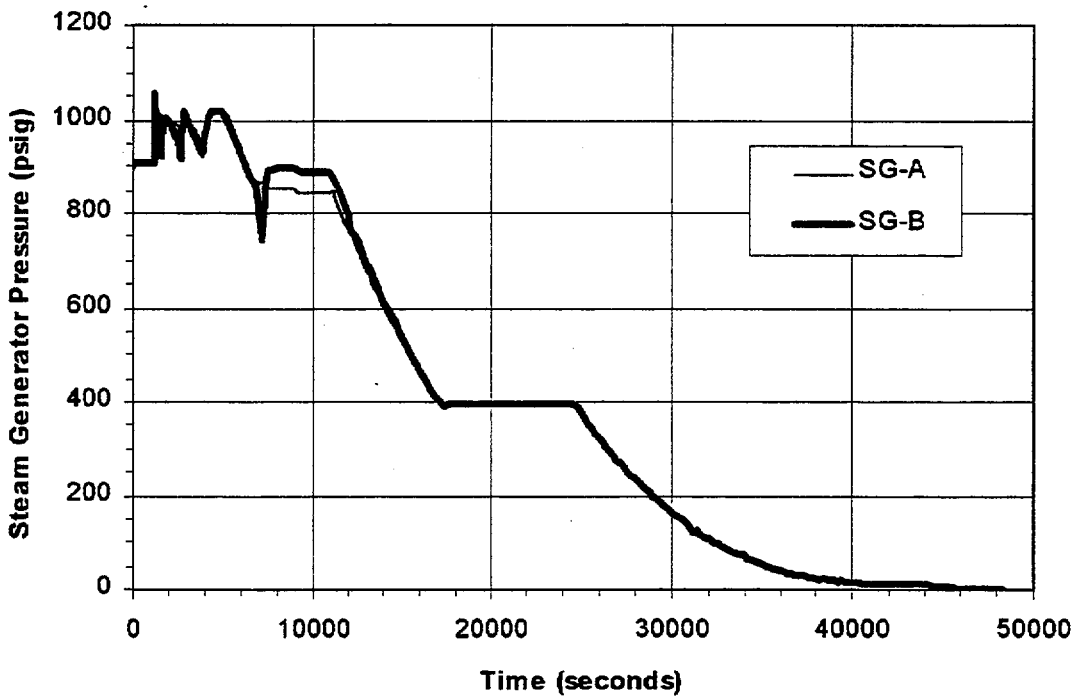
9 Figure 15-151.
9 Steam Generator Tube Rupture - Break Flow



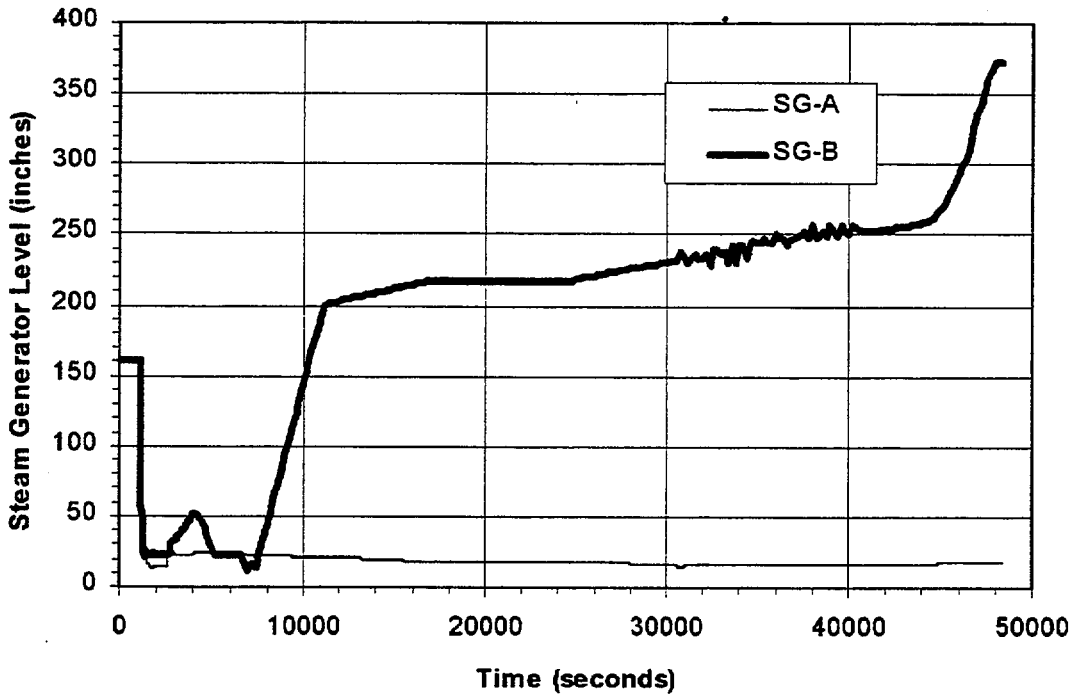
9 Figure 15-152.
9 Steam Generator Tube Rupture - RCS Pressure



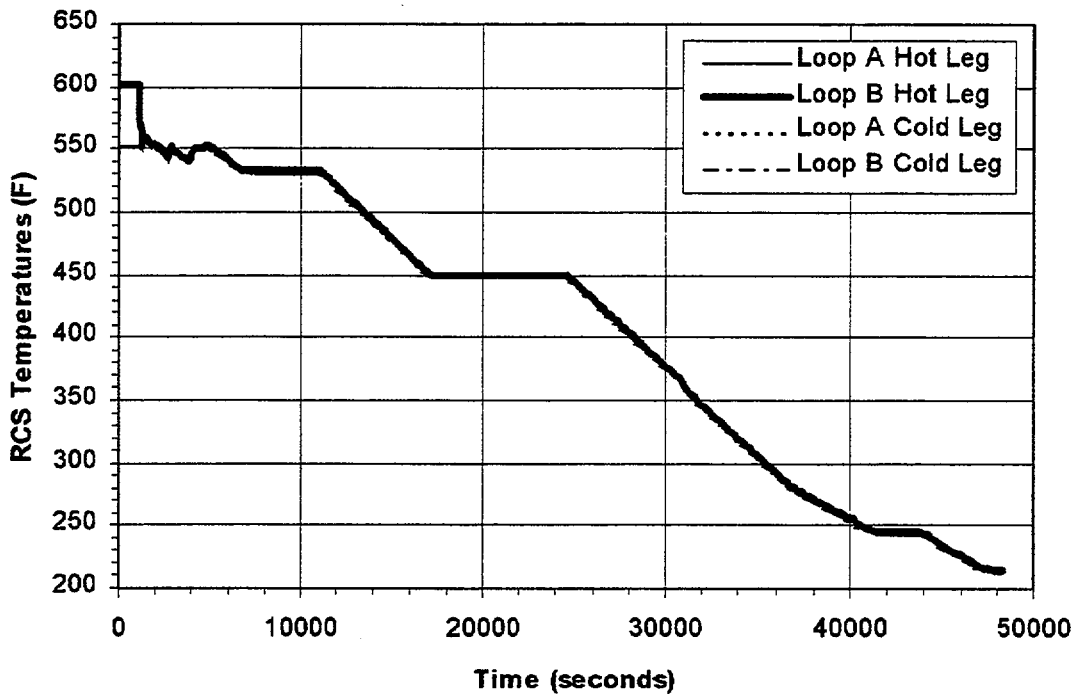
9 Figure 15-153.
9 Steam Generator Tube Rupture - Pressurizer Level



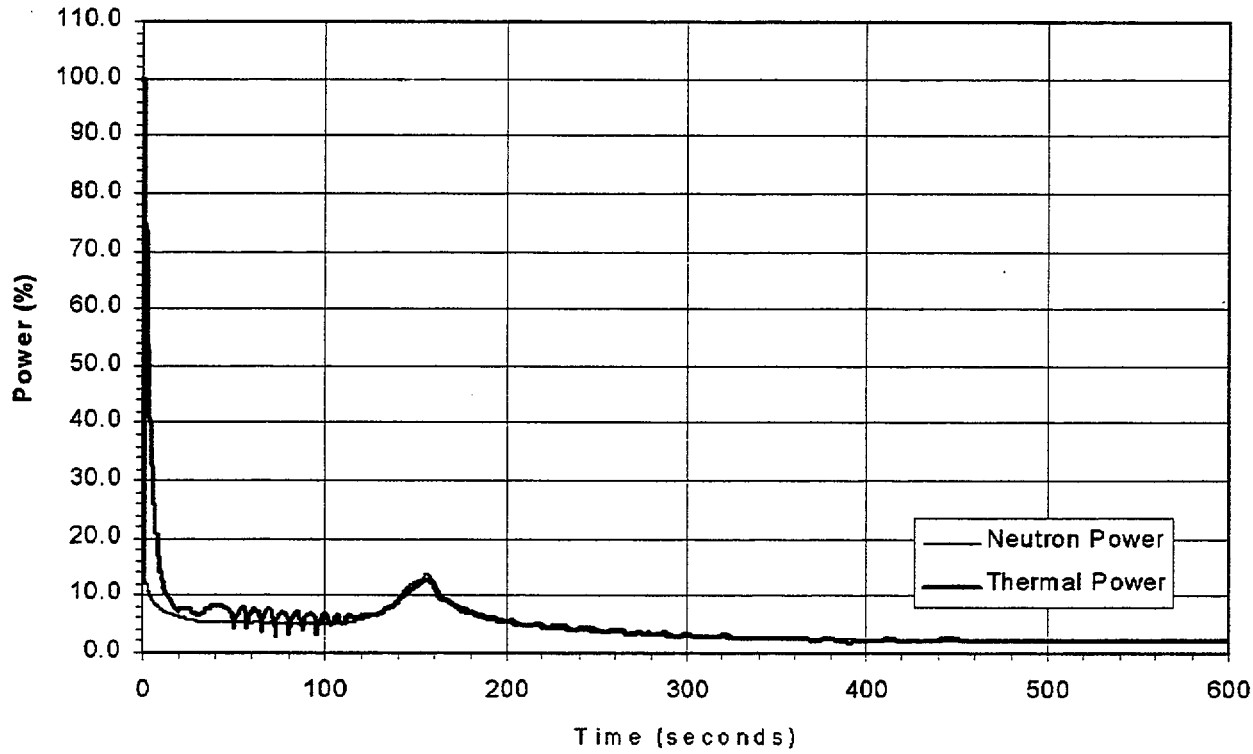
9 Figure 15-154.
9 Steam Generator Tube Rupture - Steam Generator Pressure



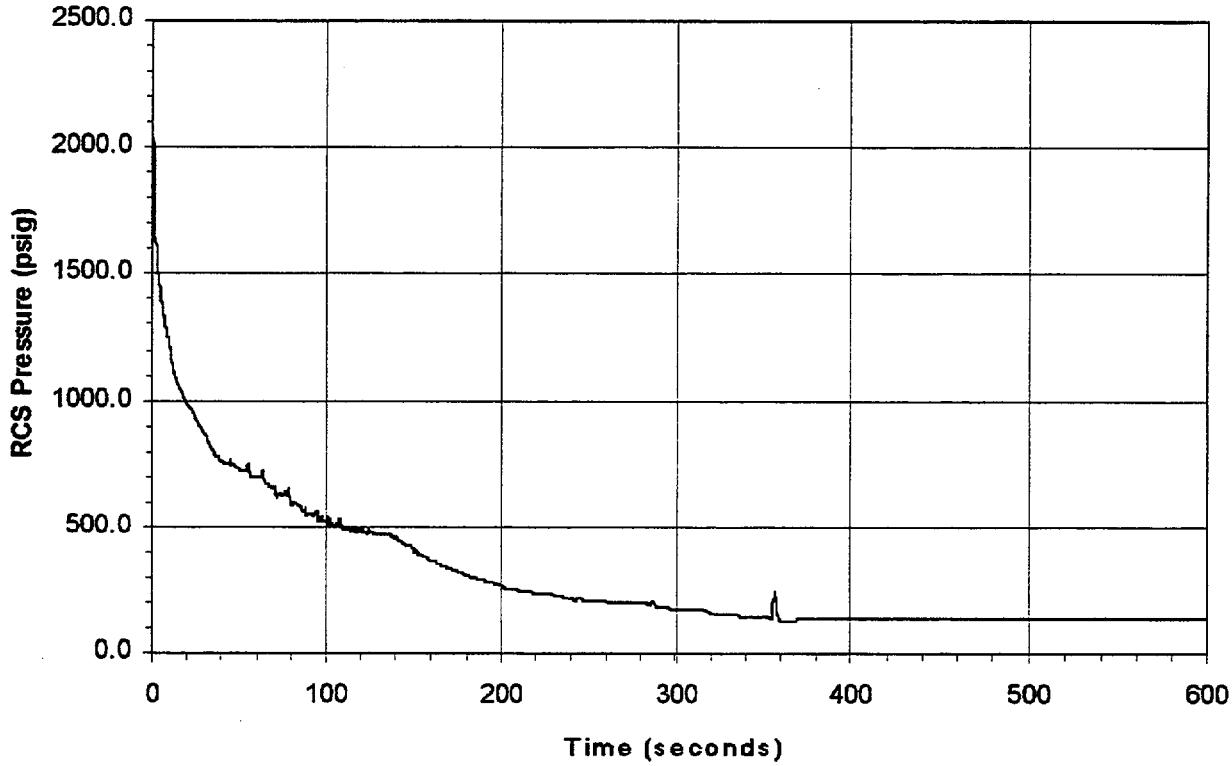
9 Figure 15-155.
9 Steam Generator Tube Rupture - Steam Generator Level



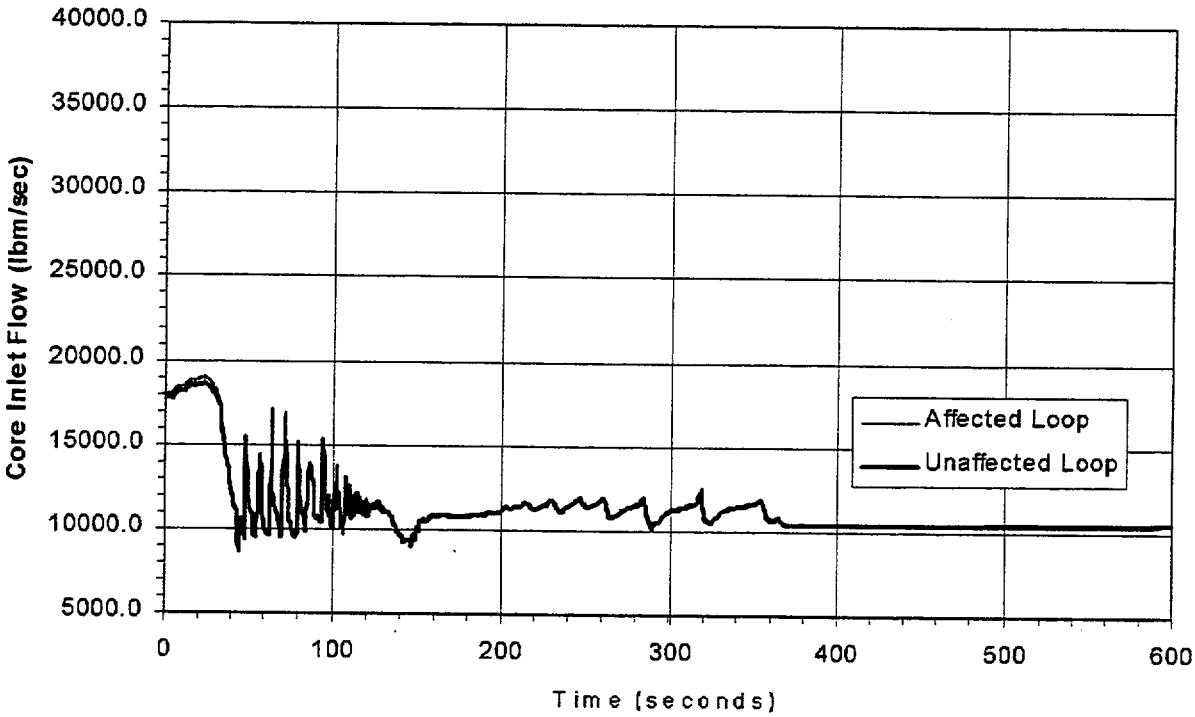
9 Figure 15-156.
9 Steam Generator Tube Rupture - RCS Temperatures



9 Figure 15-157.
9 Steam Line Break Accident - With Offsite Power - Power



9 Figure 15-158.
9 Steam Line Break Accident - With Offsite Power - RCS Pressure



9
9

Figure 15-159.
Steam Line Break Accident - With Offsite Power - Core Inlet Flow

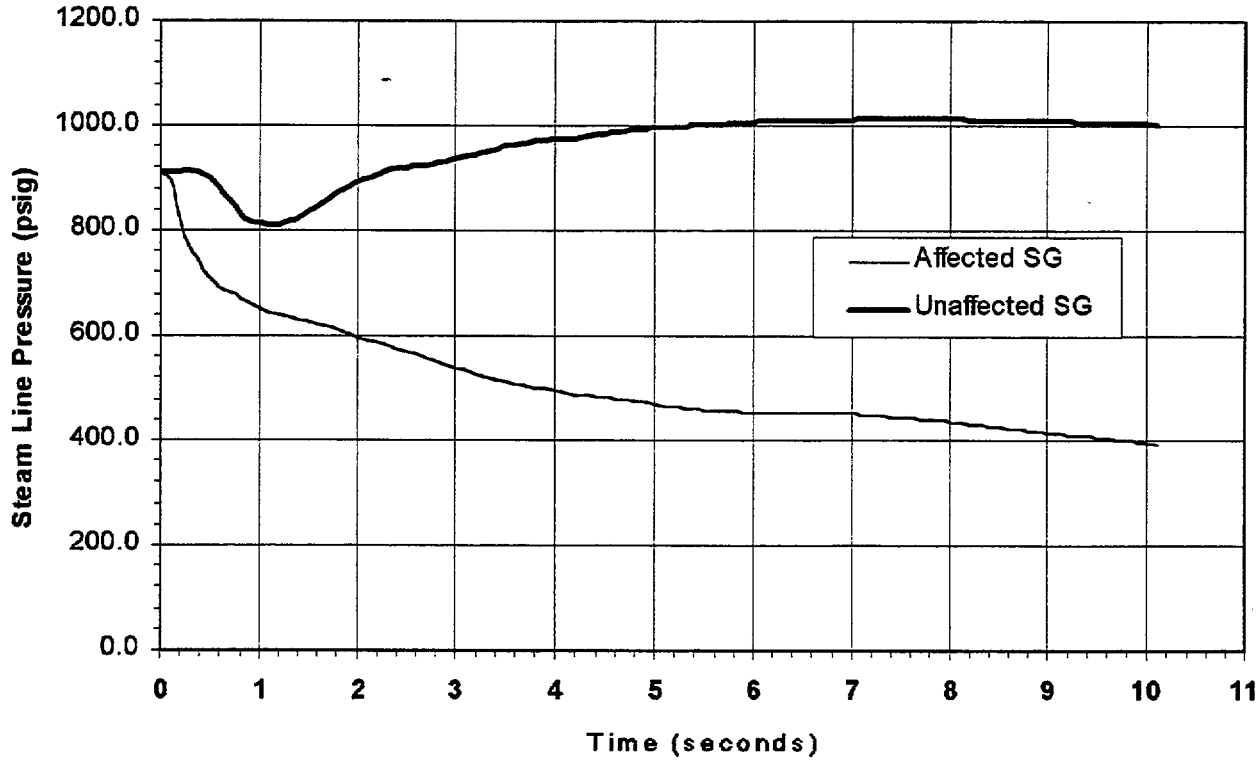
Radial Assembly Power Distribution

**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**
A						0.124	0.180	0.193	0.202	0.150						A
B				0.201	0.249	0.290	0.521	0.327	0.597	0.368	0.347	0.300				B
C			0.284	0.617	0.413	0.681	0.404	0.610	0.480	0.903	0.593	0.942	0.452			C
D		0.201	0.616	0.460	0.765	0.664	0.662	0.351	0.817	0.915	1.140	0.735	1.027	0.346		D
E		0.249	0.413	0.765	0.470	0.667	0.354	0.425	0.451	0.969	0.758	1.323	0.745	0.465		E
F	0.124	0.290	0.682	0.665	0.667	0.295	0.443	0.291	0.592	0.472	1.192	1.262	1.357	0.615	0.277	F
G	0.180	0.521	0.405	0.662	0.354	0.443	0.253	0.340	0.369	0.805	0.720	1.431	0.928	1.248	0.443	G
H	0.194	0.327	0.611	0.351	0.425	0.291	0.340	0.247	0.552	0.622	1.061	0.948	1.692	0.920	0.547	H
K	0.202	0.598	0.480	0.818	0.452	0.593	0.369	0.551	0.638	1.434	1.347	2.651	1.588	1.950	0.650	K
L	0.150	0.368	0.904	0.916	0.971	0.472	0.805	0.622	1.436	1.232	3.215	3.400	3.439	1.384	0.538	L
M		0.348	0.595	1.142	0.759	1.193	0.721	1.062	1.348	3.218	2.824	5.266	2.825	1.596		M
N		0.300	0.944	0.736	1.324	1.263	1.433	0.948	2.652	3.402	5.270	5.505	5.369	1.585		N
O			0.453	1.028	0.745	1.359	0.929	1.693	1.589	3.441	2.827	5.374	2.547			O
P				0.346	0.466	0.616	1.248	0.921	1.953	1.385	1.597	1.587				P
R						0.277	0.442	0.548	0.652	0.539						R
**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**

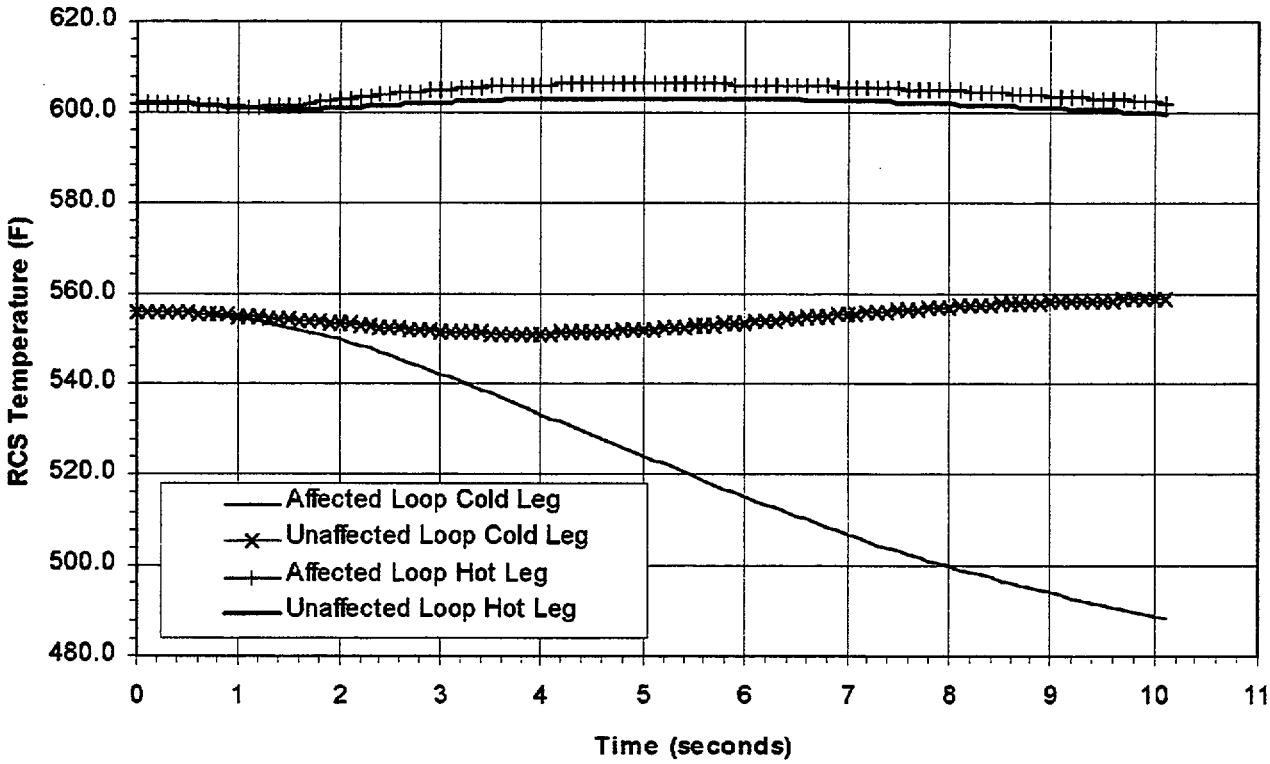
Peak Pin Power Distribution

**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**
A						0.259	0.294	0.310	0.330	0.306						A
B				0.360	0.386	0.527	0.610	0.504	0.725	0.652	0.532	0.538				B
C			0.484	0.737	0.683	0.797	0.609	0.673	0.782	1.093	0.961	1.122	0.771			C
D		0.360	0.736	0.614	0.847	0.723	0.767	0.518	1.002	1.012	1.256	0.985	1.230	0.619		D
E		0.386	0.683	0.847	0.646	0.780	0.582	0.498	0.779	1.133	1.132	1.491	1.263	0.747		E
F	0.259	0.527	0.798	0.723	0.780	0.452	0.503	0.429	0.705	0.728	1.427	1.389	1.564	1.146	0.596	F
G	0.293	0.611	0.609	0.768	0.582	0.502	0.362	0.400	0.575	0.919	1.140	1.586	1.257	1.481	0.731	G
H	0.316	0.506	0.674	0.516	0.499	0.427	0.394	0.427	0.797	1.076	1.439	1.560	1.981	1.524	0.943	H
K	0.331	0.727	0.783	1.003	0.780	0.707	0.573	0.785	1.182	2.010	2.596	3.438	2.752	2.541	1.075	K
L	0.307	0.654	1.095	1.014	1.136	0.728	0.920	1.070	2.014	2.219	4.301	4.022	4.513	2.474	1.047	L
M		0.533	0.962	1.258	1.127	1.428	1.142	1.440	2.596	4.307	4.707	6.057	5.092	2.719		M
N		0.539	1.125	0.986	1.492	1.391	1.589	1.553	3.439	4.024	6.065	6.029	6.695	2.883		N
O			0.772	1.231	1.264	1.566	1.259	1.981	2.753	4.515	5.097	6.699	4.595			O
P				0.620	0.748	1.147	1.481	1.531	2.542	2.475	2.721	2.886				P
R						0.596	0.730	0.963	1.077	1.049						R
**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**

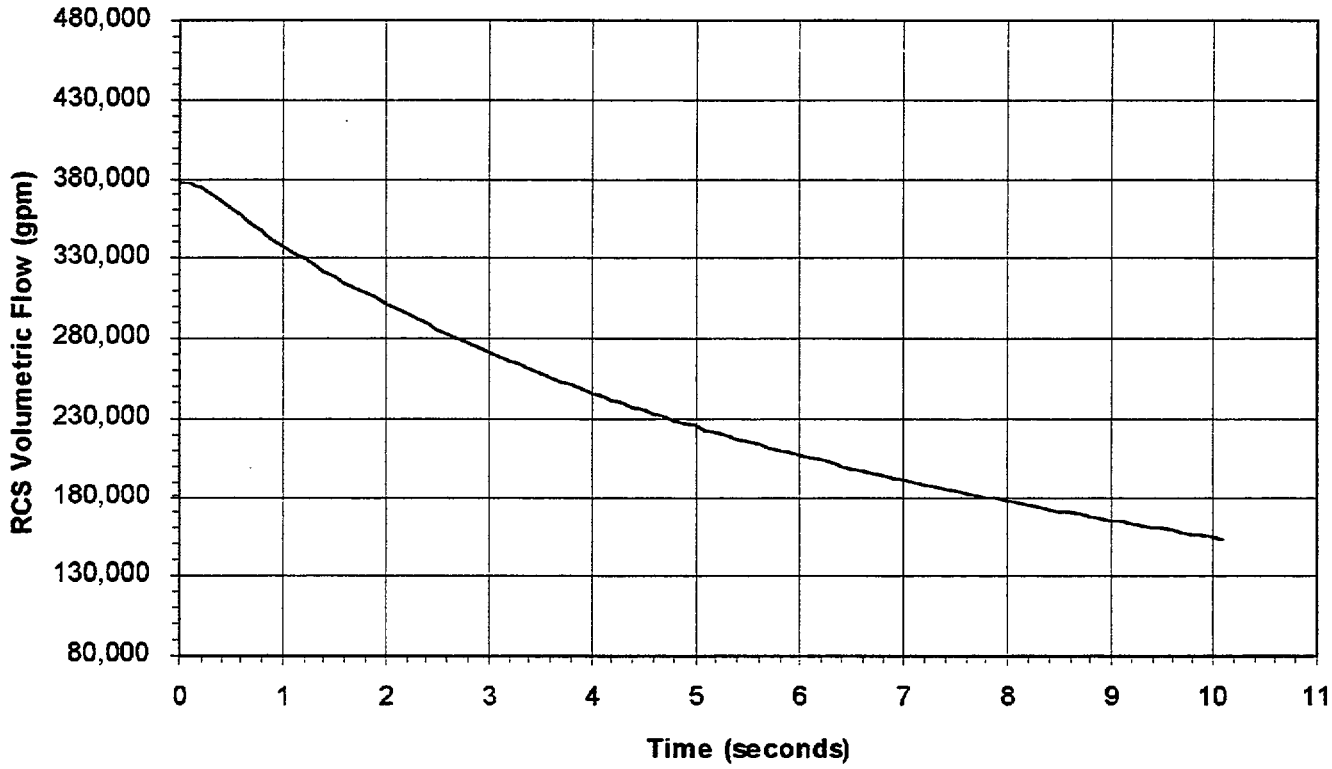
9 **Figure 15-160.**
9 **Steam Line Break Accident - With Offsite Power - Core Power Distribution**



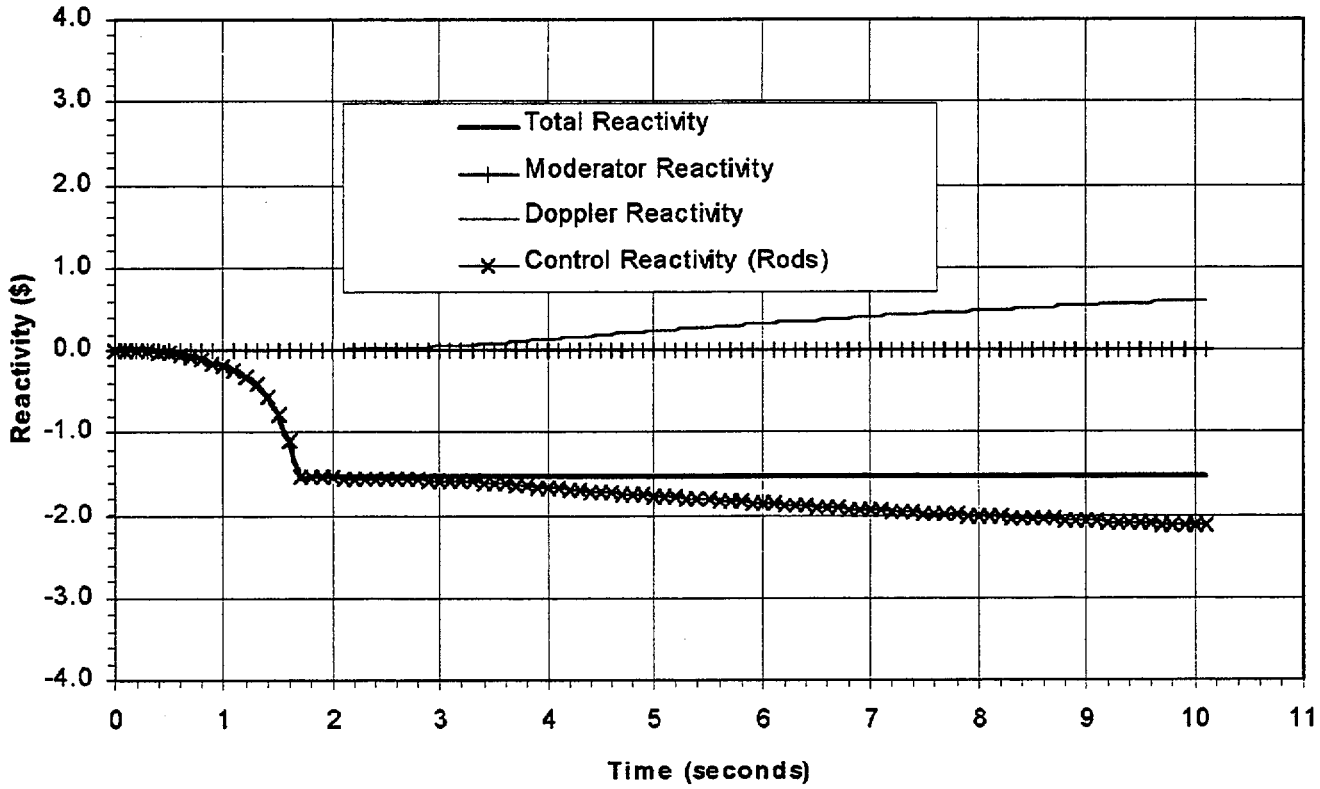
9 Figure 15-161.
9 Steam Line Break Accident - Without Offsite Power - Steam Line Pressure



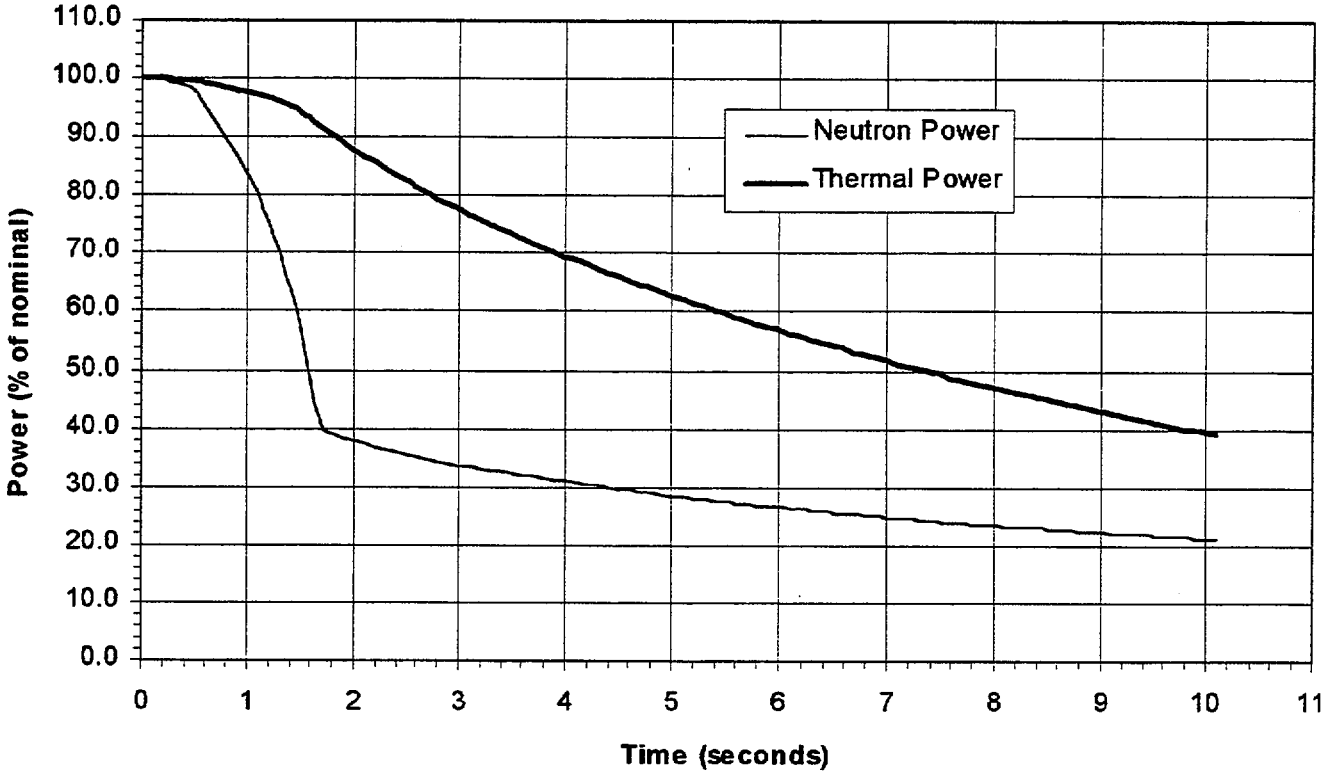
9 Figure 15-162.
9 Steam Line Break Accident - Without Offsite Power - RCS Temperatures



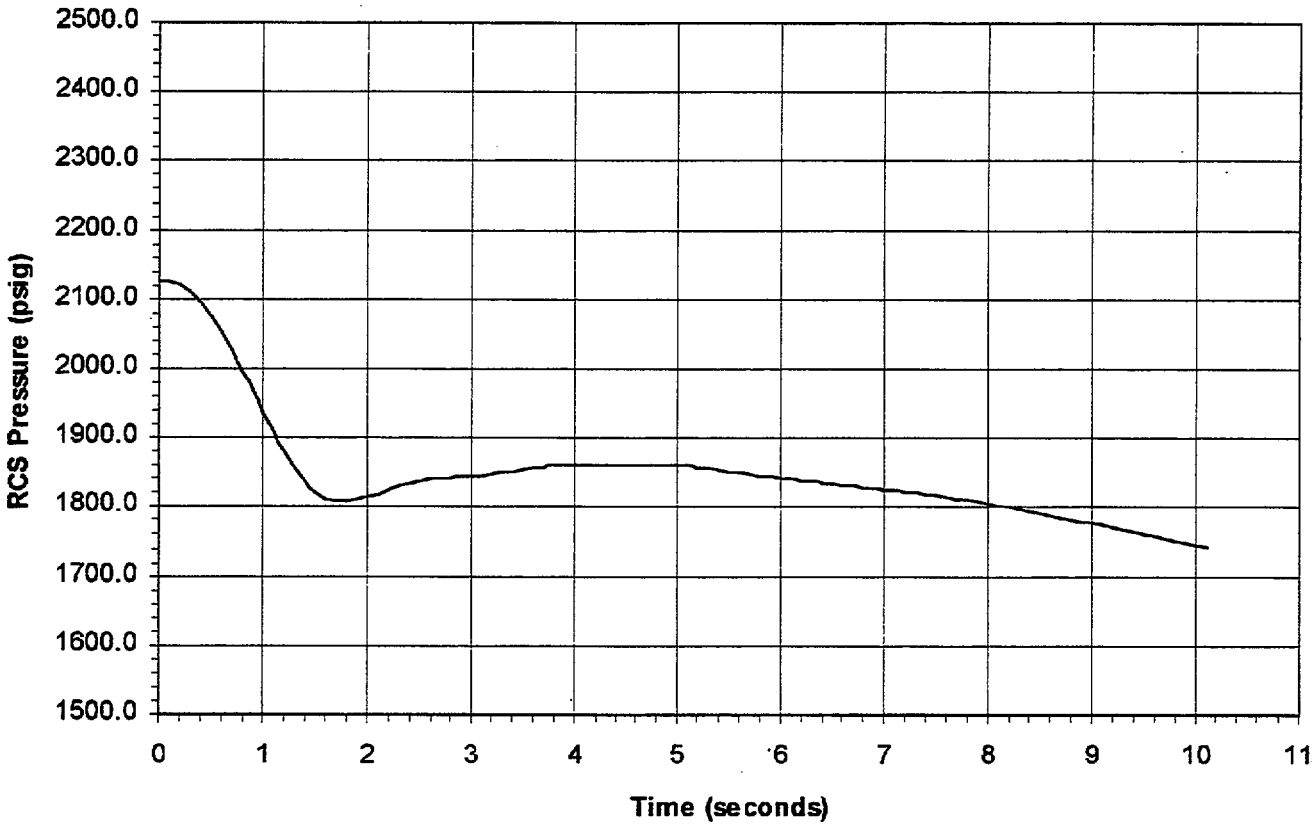
9 Figure 15-163.
9 Steam Line Break Accident - Without Offsite Power - RCS Flow



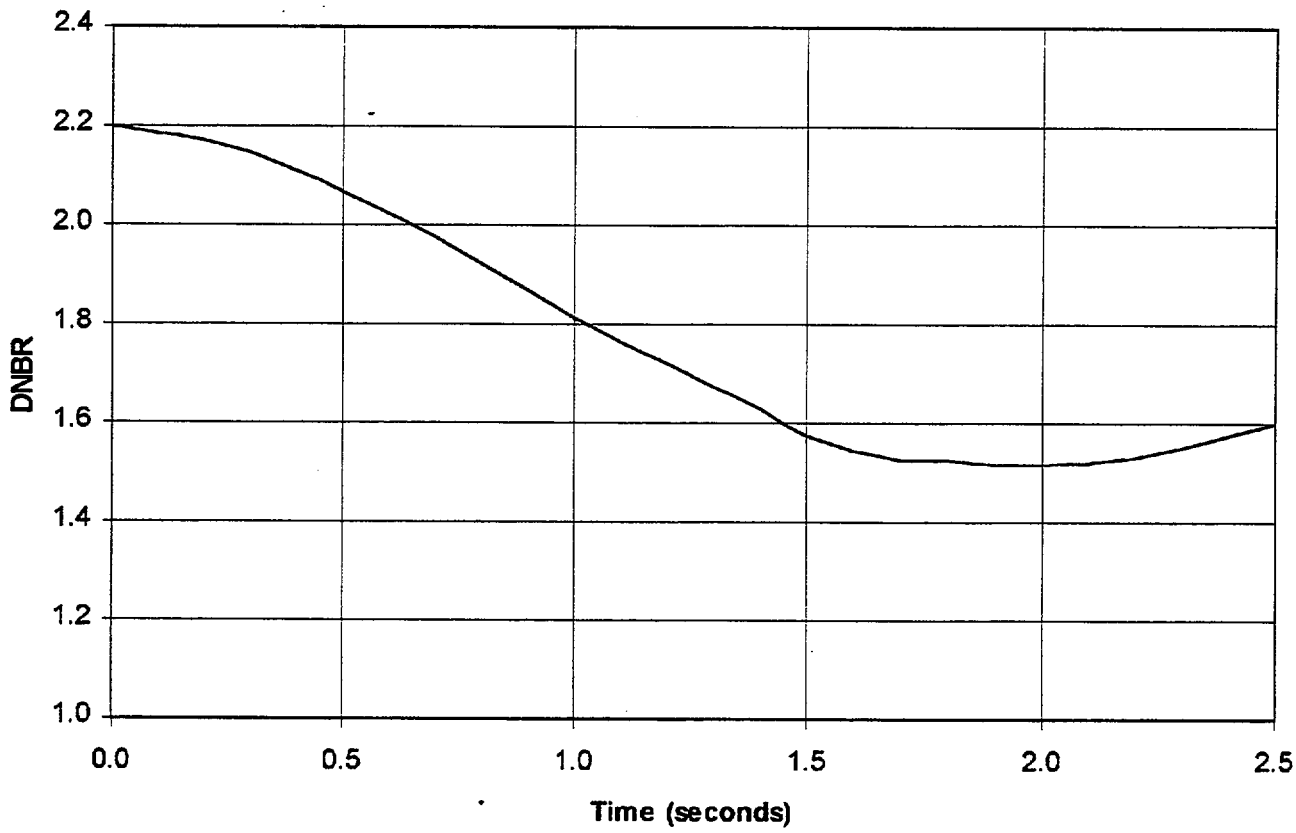
9 Figure 15-164.
9 Steam Line Break Accident - Without Offsite Power - Reactivity



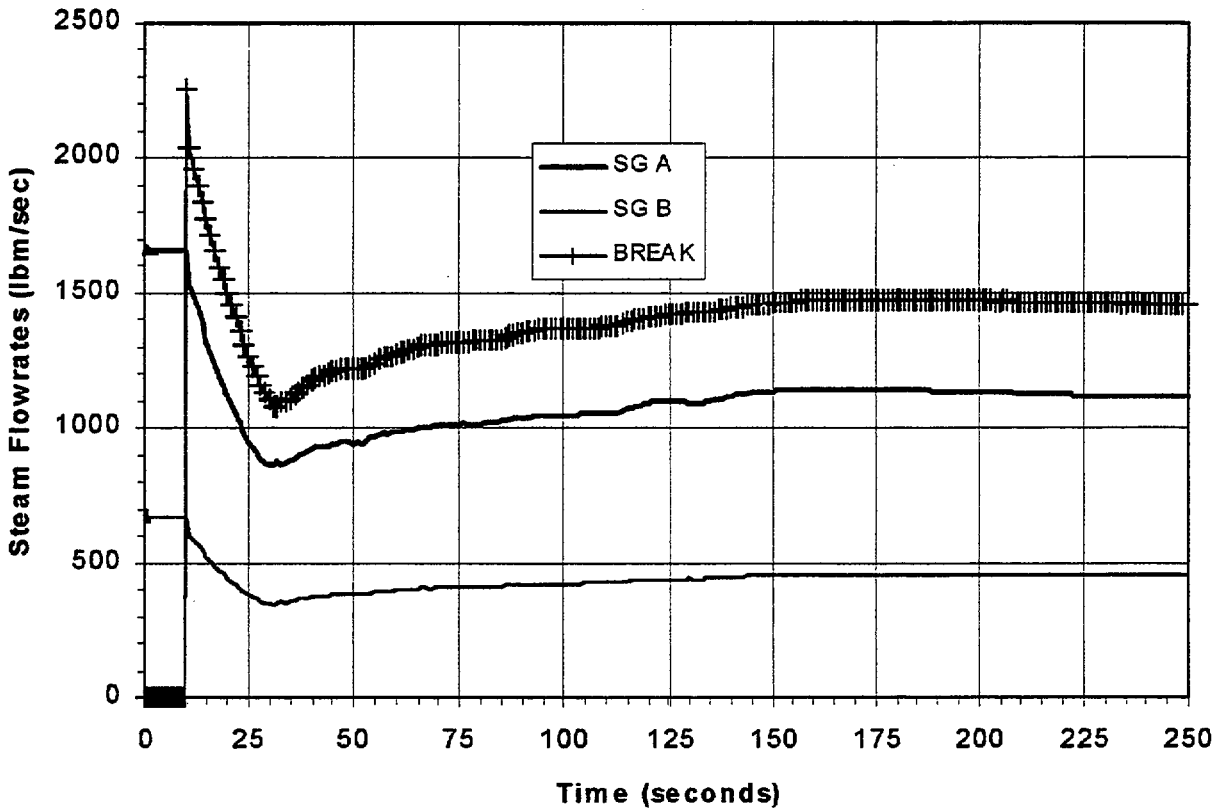
9 Figure 15-165.
9 Steam Line Break Accident - Without Offsite Power - Power



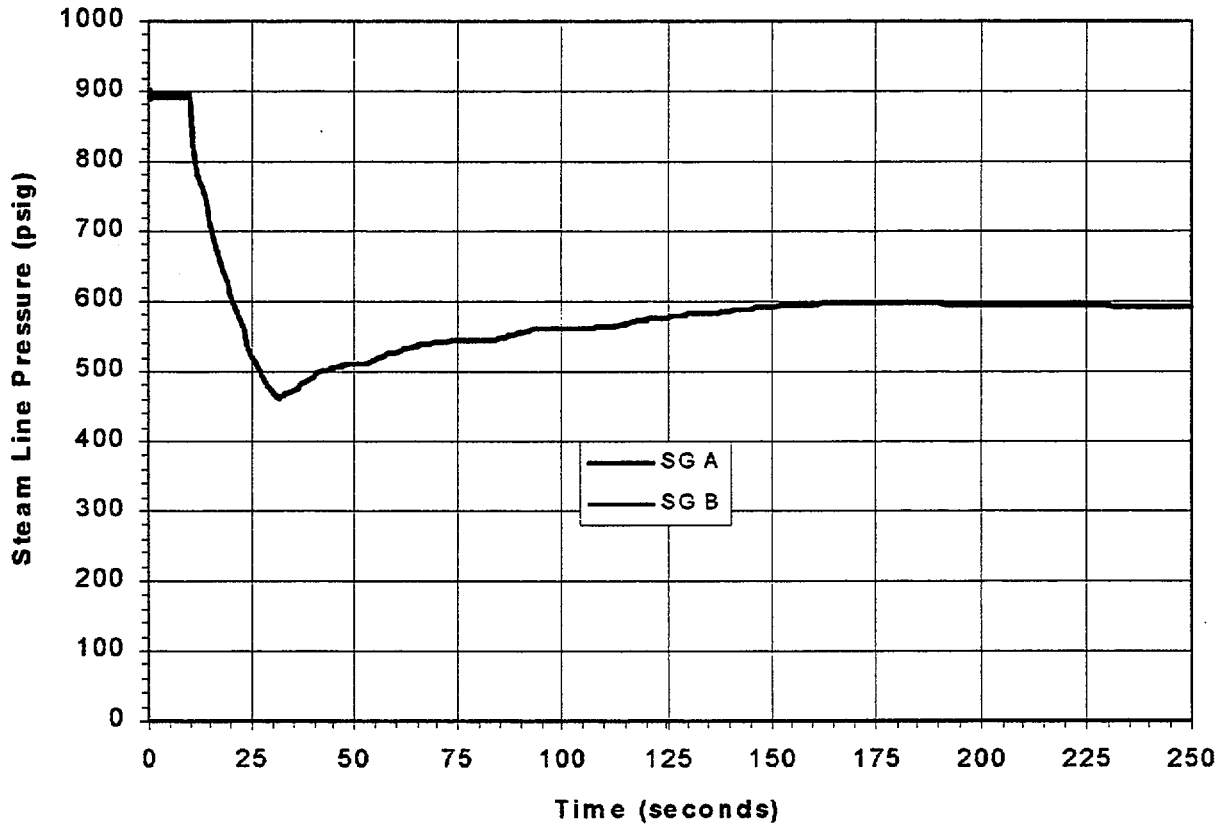
9 Figure 15-166.
9 Steam Line Break Accident - Without Offsite Power - RCS Pressure



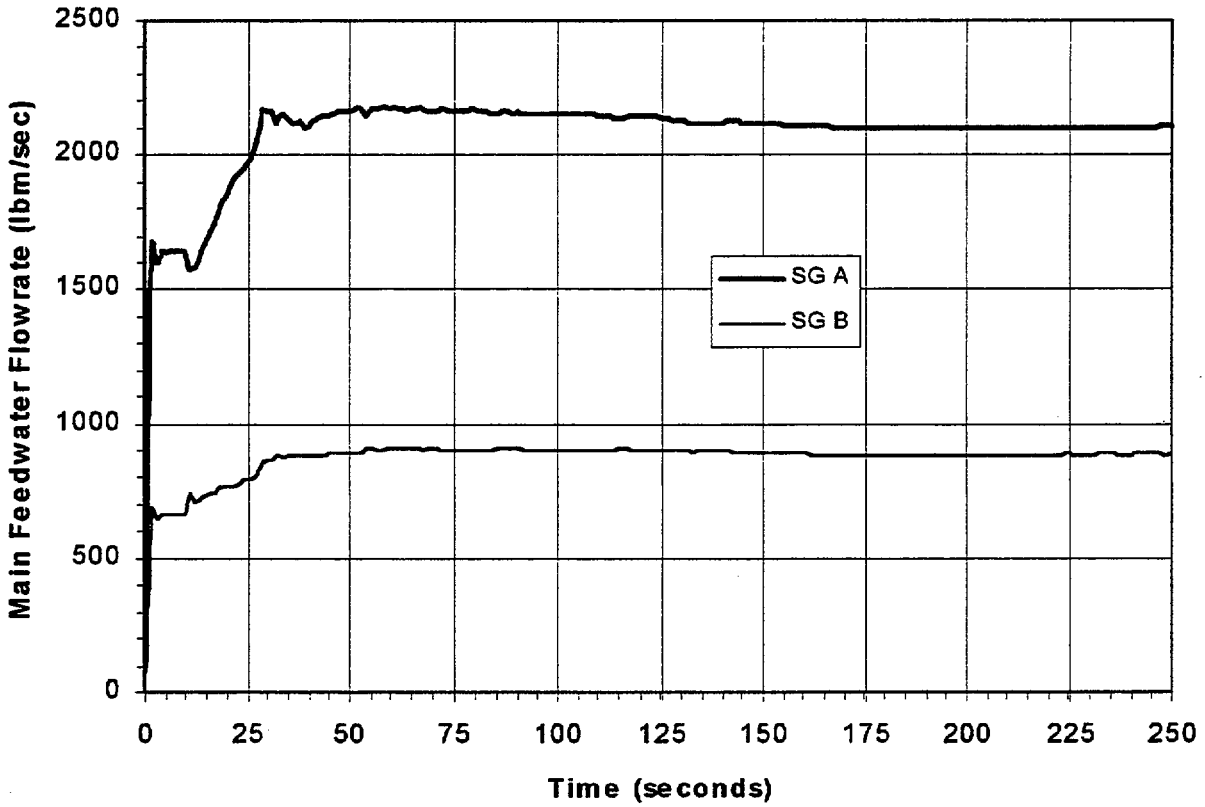
9 Figure 15-167.
9 Steam Line Break Accident - Without Offsite Power - DNBR



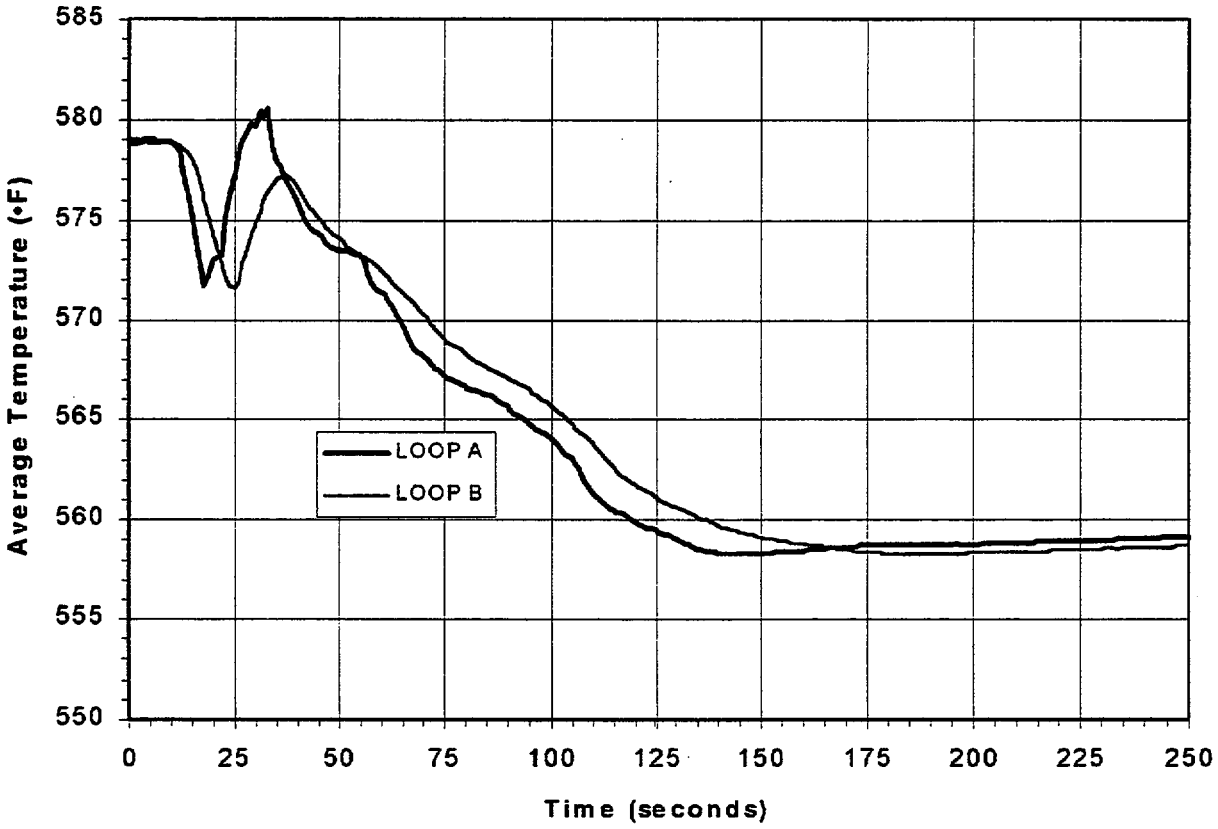
9 Figure 15-168.
9 Small Steam Line Break Accident - Steam Flowrate



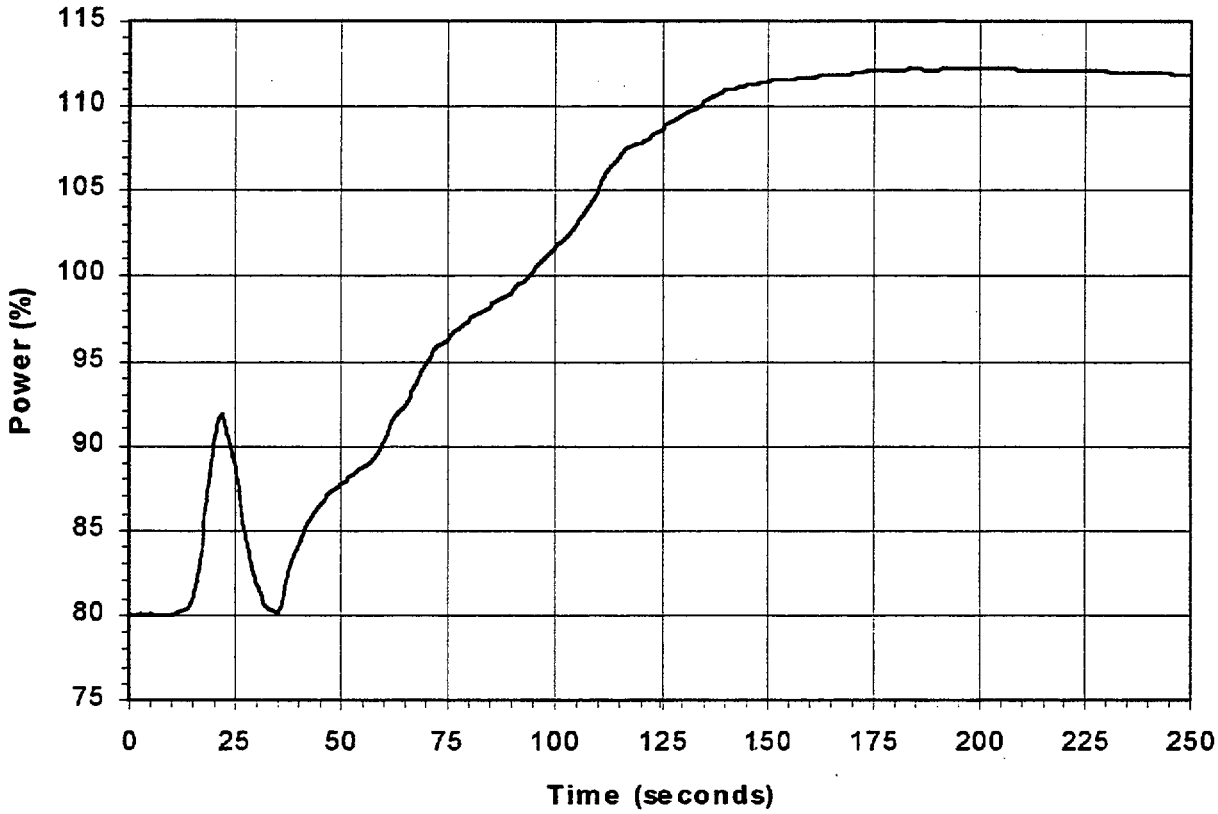
9 Figure 15-169.
9 Small Steam Line Break Accident - Steam Line Pressure



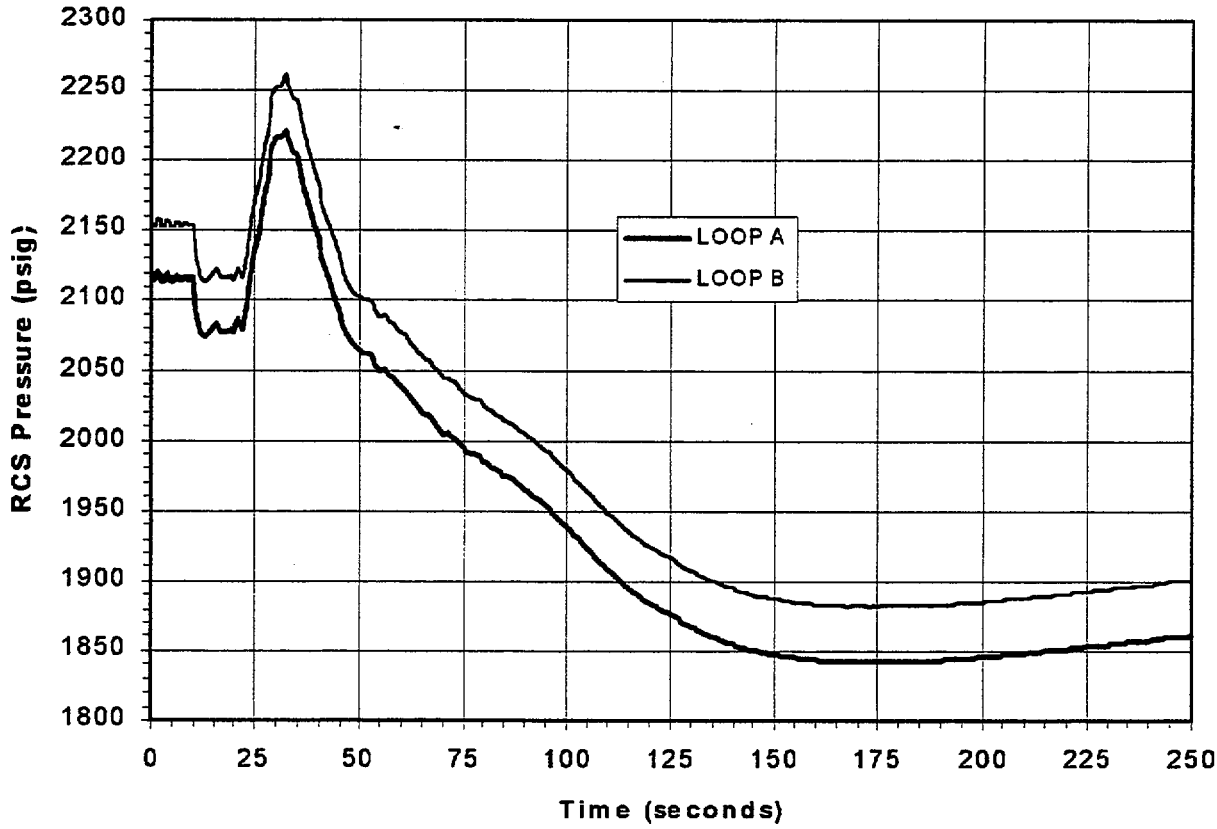
9 Figure 15-170.
9 Small Steam Line Break Accident - Main Feedwater Flowrate



9 Figure 15-171.
9 Small Steam Line Break Accident - Average Temperature



9 Figure 15-172.
9 Small Steam Line Break Accident - Power



9 Figure 15-173.
9 Small Steam Line Break Accident - RCS Pressure

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CHAPTER 16. SELECTED LICENSEE COMMITMENTS

8 **Note:** CONTAINED IN A SEPARATE HARDCOPY MANUAL ONLY

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CHAPTER 17. QUALITY ASSURANCE

The Duke Power Company Quality Assurance Program is presented in the Duke Power Company Topical Report, "Quality Assurance Program," DUKE-1A. The report is organized like and is generically used for Chapter 17, "Quality Assurance" - Quality Assurance of Duke's Safety Analysis Reports.

The Duke quality assurance program conforms to applicable regulatory requirements such as 10CFR 50,
1 Appendix B and to approved industry standards such as ANSI N45.2-1971 and ANSI N18.7-1976 and corresponding daughter standards, or to equivalent alternatives. The Duke Power quality assurance program also conforms to the regulatory position of the NRC Regulatory Guides listed in Table 17.0-1 of this report with the exception of the clarifications, modifications, and alternatives stated therein.

Section 17 describes the purpose of this report, provides definitions, and shows conformance to regulations, standards, and guides.

1

1 Section 17.3 describes the quality assurance program and organization for station operation.

1 The description in Section 17.3 follows the format of NUREG-0800, "Standard Review Plan for the
1 Review of Safety Analysis Reports for Nuclear Power Plants", except that the Duke Power Company
1 Quality Assurance Program is based on ANSI N18.7-1976 in lieu of ANSI/ASME NQA-1 and NQA-2. The topical is intended to be a comprehensive up-to-date description of Duke's quality assurance program for nuclear power plants.

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CHAPTER 18. AGING MANAGEMENT PROGRAMS AND ACTIVITIES

EFFECTIVE, BUT NOT IMPLEMENTED.

Aging management programs will be implemented on or before July 1, 2001.

The purpose of this pathway is to ensure that any plant or procedure changes over the next year that might impact this section are identified upfront, while NOT requiring new surveillances to begin.

18.1 INTRODUCTION

As the current operating license holder for Oconee Nuclear Station, Duke Energy Corporation prepared an Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3 (Application) [Reference 1]. The application including information provided in additional correspondence, provides sufficient information for the NRC to complete their technical and environmental reviews and provided the basis for the NRC to make the findings required by Section 54.29 (Final Safety Evaluation Report - Final SER) [Reference 2]. Pursuant to the requirements of Section 54.21(d), the UFSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by Section 54.21 (a) and (c), respectively.

As an aid to the reader, Table 18-1 provides a summary listing of the programs, activities and time-limited aging analyses (TLAA) (topics) required for license renewal. The first column of Table 18-1 provides a listing of these topics. The second column of Table 18-1 indicates whether the topic is a Program/Activity or TLAA. The third column of Table 18-1 identifies where the description of the Program, Activity, or TLAA is located in either the Oconee UFSAR or in the Oconee Improved Technical Specifications (ITS).

Section 18.2, "One-Time Inspections for License Renewal" contains summary descriptions of the one-time inspections that have been committed to be performed prior to the period of extended operation. Section 18.3, "Aging Management Programs and Activities" contains summary descriptions of the aging management programs and periodic inspections that are ongoing through the duration of the operating licenses of Oconee Nuclear Station. Section 18.4, "Additional Commitments" contains additional commitments that are not identified in the preceding sections of Chapter 18, "Aging Management Programs and Activities"

Station documents will be established, implemented, and maintained to cover the aging management programs and activities described in Chapter 18, "Aging Management Programs and Activities."

18.2 ONE-TIME INSPECTIONS FOR LICENSE RENEWAL

18.2.1 CAST IRON SELECTIVE LEACHING INSPECTION

Purpose - The purpose of the Cast Iron Selective Leaching Inspection will be to characterize loss of material due to selective leaching of cast iron components in Oconee raw water, treated water, and underground environments.

Scope - The results of this inspection will be applicable to the cast iron components falling within the scope of license renewal. These components include pump casings in several systems along with piping, valves and other components. The Oconee raw and treated water systems containing cast iron components potentially susceptible to loss of material due to selective leaching are the Auxiliary Service Water System, the Low Pressure Service Water System, the Condenser Circulating Water System, the Service Water System (Keowee), the Chilled Water System, the Condensate System, and the High Pressure Service Water System.

Aging Effects - The inspection will determine the existence of loss of material due to selective leaching, a form of galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

Method - The Cast Iron Selective Leaching Inspection will inspect a select set of cast iron pump casings to determine whether selective leaching of the iron has been occurring at Oconee and whether loss of material due to selective leaching will be an aging effect of concern for the period of extended operation. A Brinnell Hardness check will be performed on the inside surface of a select set of cast iron pump casings to determine if this phenomenon is occurring. The results of the Cast Iron Selective Leaching Inspection will be applicable to all cast iron components within license renewal scope and installed in applicable environments.

Sample Size - A representative sample of six pump casings will be inspected for evidence of selective leaching, one from each of the following systems on-site:

- Auxiliary Service Water System
- Chilled Water System
- Low Pressure Service Water System
- High Pressure Service Water System
- Service Water System (Keowee)
- Condensate System (one inspection location on any of the three Oconee Units.)

Industry Codes or Standards - No specific codes or standards exist to address this inspection.

Frequency - The Cast Iron Selective Leaching Inspection is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to selective leaching as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Corrective Action - Any unacceptable loss of material due to selective leaching requires an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem

Investigation Process will apply to all structures and components within the scope of the Cast Iron Selective Leaching Inspection.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.2 GALVANIC SUSCEPTIBILITY INSPECTION

Purpose - The purpose of the Galvanic Susceptibility Inspection will be to characterize the loss of material by galvanic corrosion in carbon steel - stainless steel couples in the Oconee raw water systems.

Scope - The results of this inspection will be applicable to all galvanic couples with the focus on the carbon steel - stainless steel couples in the Oconee raw water systems falling within the scope of license renewal.

Aging Effects - The inspection will determine the existence of loss of material due to galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function.

Method - A volumetric or destructive examination at the junction of the carbon steel - stainless steel components will be performed to determine material loss from the more anodic carbon steel. The most susceptible locations will be identified. The exact method of examination will be determined at the time of the inspection.

Sample Size - A sentinel population of the more susceptible locations on all three Oconee units, Keowee, and Standby Shutdown Facility will be selected for this inspection from the following raw water systems within the scope of license renewal.

- Auxiliary Service Water System
- Chilled Water System (raw water portion of the chillers)
- Component Cooling System (raw water portion of the Component Cooler)
- Condensate System (raw water portions of the Condensate Cooler and Main Condenser within the scope of license renewal)
- Condenser Circulating Water System
- Diesel Jacket Water Cooling System (raw water portion of the jacket water heat exchanger)
- High Pressure Service Water System
- Low Pressure Injection (raw water portion of the Decay Heat Removal Cooler)
- Low Pressure Service Water System
- Service Water System (Keowee)
- Standby Shutdown Facility Auxiliary Service Water System
- Turbine Generator Cooling Water System (Keowee)
- Turbine Sump Pump System (Keowee)

Areas of low to stagnant flow in Oconee raw water systems which contain carbon steel - stainless steel couples are the most susceptible locations. Engineering practice at Duke has been to use stainless steel as a replacement material in raw water systems for several years. Since engineering practice will continue to use stainless steel as an acceptable substitute material, the size of the sentinel population will be dependent on the number of susceptible locations at the time of the inspection.

9 **Industry Codes or Standards** - No code or standard exists to guide or govern this inspection. Component
9 wall thickness acceptability will be judged in accordance with the Oconee component design code of
9 record.

9 **Frequency** - The Galvanic Susceptibility Inspection is a one-time inspection.

9 **Acceptance Criteria or Standard** - No unacceptable indication of loss of material due to galvanic corrosion
9 as determined by engineering analysis.

9 **Corrective Action** - Any unacceptable loss due of material due to galvanic corrosion requires that an
9 engineering analysis be performed to determine potential impact on component intended function.
9 Specific corrective actions will be implemented in accordance with the Problem Investigation Process.
9 The Problem Investigation Process will apply to all structures and components within the scope of the
9 Galvanic Susceptibility Inspection.

9 **Timing of New Program or Activity** - Following issuance of renewed operating licenses for Oconee
9 Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of
9 Oconee Unit 1).

9 **Regulatory Basis** - Application [Reference 1] and Final SER [Reference 2].

9 18.2.3 KEOWEE AIR AND GAS SYSTEMS INSPECTION

9 **Purpose** - The purpose of the Keowee Air and Gas Systems Inspection will be to characterize the loss of
9 material due to general corrosion of the carbon steel components within the Carbon Dioxide, Depressing
9 Air, and Governor Air Systems at Keowee that may be exposed to condensation.

9 **Scope** - The results of this inspection will be applicable to the carbon steel components within the license
9 renewal portion of the Carbon Dioxide, Depressing Air, and Governor Air Systems on each unit at
9 Keowee.

9 **Aging Effects** - The inspection will determine the existence of loss of material due to general corrosion of
9 carbon steel components in the Carbon Dioxide, Depressing Air, and Governor Air Systems. The
9 inspection will assess the likelihood of the impact of this aging effect on the component intended function.

9 **Method** - An inspection of select portions of the each system will determine whether loss of material due
9 to general corrosion will be an aging effect of concern for the period of extended operation. The results
9 Keowee Air and Gas Systems Inspection will determine the need for additional programmatic oversight to
9 manage this aging effect.

9 For the Carbon Dioxide System, the discharge piping low elevation point will be determined. A
9 volumetric examination will conducted on a portion of carbon steel pipe in and around this low point of
9 the Carbon Dioxide System.

9 For the Depressing Air System, a volumetric examination will be conducted on a portion of piping
9 between the control valves and the Keowee unit turbine head cover.

9 For the Governor Air System, a visual examination of the bottom half of the interior surface of the air
9 receiver tanks will determine the presence of corrosion. The visual examination will also serve to
9 characterize any instance of corrosion. Piping between the air receiver tank and the governor oil pressure
9 tank will receive a volumetric examination.

9 **Sample Size** - For the Carbon Dioxide System, the inspection will include four feet of pipe around the
9 system low elevation point (two feet upstream and downstream).

9 For the Depressing Air System, the inspection will include one of the two four-foot sections of piping
9 between the control valves and the Keowee unit headcover.

9 For the Governor Air System, the inspection will include the lower half of each Air Receiver Tank and
9 one of the two four-foot sections of the piping between the air receiver tanks and the governor oil pressure
9 tanks.

9 **Industry Code or Standards** - No code or standard exists to guide or govern this inspection.

9 **Frequency** - The Keowee Air and Gas Systems Inspection is a one-time inspection.

9 **Acceptance Criteria or Standard** - Any indication of loss of material will be documented and the need for
9 further analysis determined. No unacceptable loss of material will be permitted, as determined by
9 engineering analysis. Component wall thickness acceptability will be judged in accordance with the
9 component design code of record.

9 **Corrective Action** - Any unacceptable indication of loss of material due to corrosion will require that an
9 engineering analysis be performed to determine proper corrective action. Specific corrective actions will be
9 implemented in accordance with the Problem Investigation Process. The Problem Investigation Process
9 will apply to all structures and components within the scope of the Keowee Air and Gas Systems
9 Inspection.

9 **Timing of New Program or Activity** - Following issuance of renewed operating licenses for Oconee
9 Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of
9 Oconee Unit 1).

9 **Regulatory Basis** - Application [Reference 1] and Final SER [Reference 2].

9 18.2.4 ONCE THROUGH STEAM GENERATOR UPPER LATERAL SUPPORT
9 INSPECTION

9 **Purpose** - The purpose of the OTSG Upper Lateral Support Inspection is to determine whether cracking
9 of the OTSG upper lateral support lubrite pads has occurred and to validate that the condition of the
9 lubrite pads is acceptable for the period of extended operation.

9 **Scope** - The results of this inspection will be applicable to all thirty lubrite pads installed at Oconee (ten
9 per unit).

9 **Aging Effects** - The applicable aging effect is cracking of the lubrite pads by gamma irradiation.

9 **Method** - A visual inspection of the accessible surfaces of a sample population of lubrite pads will be
9 performed to determine if the pads are cracking.

9 **Sample Size** - The sample size will be five lubrite pads on one OTSG upper lateral support. The OTSG
9 containing these pads will be randomly selected from the total population of six OTSG at Oconee.

9 **Industry Codes or Standards** - No code or standard exists to guide or govern this inspection.

9 **Frequency** - The OTSG Upper Lateral Support Inspection is a one-time inspection.

9 **Acceptance Criteria or Standard** - No visible cracking in the lubrite pads.

9 **Corrective Action** - If the sample lubrite pads are cracked, then the affected pads will be replaced and the
9 remaining 25 lubrite pads will be inspected. Specific corrective actions will be implemented in accordance
9 with the Duke Quality Assurance Program.

9 **Timing of New Program or Activity** - Following issuance of renewed operating licenses for Oconee
9 Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of
9 Oconee Unit 1).

9 **Regulatory Basis** - Application [Reference 1] and Final SER [Reference 2].

9 18.2.5 PRESSURIZER EXAMINATIONS

9 18.2.5.1 Pressurizer Cladding, Internal Spray Line, and Spray Head Examination

9 **Purpose** - The purpose of the Pressurizer Cladding, Internal Spray Line, and Spray Head Examination
9 will be to assess the condition of the pressurizer cladding, internal spray line, and spray head.

9 **Scope** - The scope of this activity will include the cladding and attachment welds to the cladding of all
9 three pressurizers at the Oconee units and to the internal spray line and spray head of all three pressurizers
9 at the Oconee units, including the fasteners that connect the spray line and spray head to the internal
9 surface of the pressurizer.

9 **Aging Effects** - The aging effects of concern are cracking of cladding by thermal fatigue, which may
9 propagate to the underlying ferritic steel. Cracking of the internal spray line by fatigue and cracking and
9 loss of fracture toughness due to thermal embrittlement of the spray head [Reference 3] are also aging
9 effects.

9 **Method** - Visual examination (VT-3) of the clad inside surfaces of the pressurizer (100% coverage of the
9 accessible surface) including attachment welds to the pressurizer will be performed. Historical data
9 (Haddam Neck) indicates cracking may occur adjacent to the heater bundles, if at all. Therefore, the
9 examination will focus on cladding adjacent to the heater bundles. In addition, visual inspections have
9 been shown to be adequate for detecting cracks in cladding at Haddam Neck; cracking that extended to
9 underlying ferritic steel was found due to the observance of rust.

9 Visual examination (VT-3) of the internal spray line and spray head, including the fasteners that are used
9 to attach the spray line to the internal surface of the pressurizer will also be performed.

9 **Sample Size** - The examination will be performed on the cladding (100% coverage of the accessible
9 surface), spray head, and internal spray line of one pressurizer at Oconee.

9 **Industry Code or Standards** - ASME Section XI.

9 **Frequency** - The Pressurizer Cladding, Internal Spray Line, and Spray Head Examination is a one-time
9 inspection.

9 **Acceptance Criteria or Standard** - Acceptance standards for visual examinations will be in accordance
9 with ASME Section XI VT-3 examinations.

9 **Corrective Action** - If cracks are detected in the cladding that extend to the underlying ferritic steel,
9 acceptance standards for Examination Categories B-B and B-D may be applicable to subsequent
9 volumetric examination of ferritic steel.

9 If cracks are detected in the internal spray piping, acceptance standards for Examination Category B-J
9 may be applied. If cracks are detected in the spray head, engineering analysis will determine corrective
9 actions that could include replacement of the spray head.

9 The need for subsequent examinations will be determined after the results of the initial examination are
9 available.

9 Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

9 **Timing of New Program or Activity** - Following issuance of renewed operating licenses for Oconee
9 Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of
9 Oconee Unit 1).

9 **Regulatory Basis** - Application [Reference 1] and Final SER [Reference 2].

9 18.2.5.2 Pressurizer Heater Bundle Penetration Welds Examination

9 **Purpose** - The purpose of the Pressurizer Heater Bundle Penetration Welds Examination will be to assess
9 the condition of the Unit 1 pressurizer heater penetration welds.

9 **Scope** - The results of this examination will be applicable to the heater sheath-to-sleeve and heater
9 sleeve-to-diaphragm plate penetration welds for the pressurizer heater bundles of Oconee Unit 1
9 (Reference Figure 2-8 of BAW-2244A). Inspections of Unit 2 or Unit 3 heater bundle welds are not
9 required. [Reference 4]

9 **Aging Effects** - The aging effect of concern is cracking at heater bundle penetration welds which may lead
9 to coolant leakage.

9 **Method** - For the heater bundle that is removed, a surface examination of sixteen peripheral welds on one
9 bundle will be performed. A visual examination (VT-3 or equivalent) of the remaining welds of the heater
9 bundle will be performed.

9 **Sample Size** - The examination will include sixteen peripheral heater penetration welds on one heater
9 bundle from Oconee Unit 1, whichever heater bundle is removed first. The examination will include the
9 heater sheath-to-sleeve and heater sleeve-to-diaphragm plate penetration welds of the sixteen peripheral
9 heaters.

9 **Industry Code or Standards** - ASME Section XI.

9 **Frequency** - The Pressurizer Heater Bundle Penetration Welds Examination is a one-time inspection.

9 **Acceptance Criteria or Standard** - Acceptance standards for surface examinations and visual examination
9 (VT-3) will be in accordance with ASME Section XI.

9 **Corrective Action** - If the results of the inspection are not acceptable, then the results may be used as a
9 baseline inspection for establishing a longer term programmatic action covering all Oconee pressurizer
9 heater bundles.

Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - The surface examinations of the sixteen peripheral heater penetration welds will be performed upon removal of a pressurizer heater bundle. This examination will be aligned to when a Unit 1 heater bundle is replaced whenever that may occur, due to the impractical nature of such an inspection otherwise. The failure of a structural weld that attaches the heater sheath to the Alloy 600 heater sleeve or failure of the weld that attaches the heater sleeve to the Alloy 600 diaphragm plate would result in leakage within the make-up system capacity and the integrity of the heater bundle bolted closure would not be compromised. No loss of pressurizer function would occur due to leakage at either of these welds. The examination will provide insights into the condition of the other similarly constructed pressurizer heater bundles in Oconee Unit 1. [Reference 5]

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.6 REACTOR BUILDING SPRAY SYSTEM INSPECTION

Purpose - The purpose of Reactor Building Spray System Inspection will be to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components within the Reactor Building Spray System periodically exposed to an borated water environment that is not monitored.

Scope - The results of this inspection will be applicable to stainless steel piping and components downstream of the containment isolation valves BS-1 and BS-2 toward their respective spray headers, a total of two lines per Oconee unit. Because the piping is open to the Reactor Building environment, unmonitored conditions exist in any borated water, which may be entrapped downstream of these valves. Results of this inspection will be applied to not only the Reactor Building Spray System, but also to the Nitrogen Purge and Blanketing System.

Aging Effects - The inspection will determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping due to the periodic presence of borated water in the Reactor Building Spray piping open to the Reactor Building environment. The inspection will assess the likelihood of the impact of these aging effects on the component intended function.

Method - An inspection of a select set of stainless steel piping locations will determine whether loss of material due to pitting corrosion and cracking due to stress corrosion have been occurring and whether further programmatic aging management will be required to manage these effects for license renewal. The length of susceptible piping will be determined. A volumetric examination of a length of the susceptible piping locations will be conducted for this inspection. This examination will include a stainless steel weld and heat affected zone, since this is a more likely location for stress corrosion cracking to occur.

Sample Size - The inspection will include one of the six susceptible locations. The inspection locations are the piping between valves BS-1 and BS-2 and the normally open drain valves BS-15 and BS-20. Some of the parameters Duke may use to select the most bounding inspection location are piping geometry, presence of weld and heat affected zone, accessibility of location and radiation exposure. [Reference 6]

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The Reactor Building Spray System Inspection is a one-time inspection.

Acceptance Criteria or Standard - No cracking will be permitted. Any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be

9 permitted, as determined by engineering analysis. Component wall thickness acceptability will be judged
9 in accordance with the component design code of record.

9 **Corrective Action** - Any unacceptable indication of loss of material due to pitting corrosion or cracking or
9 cracking due to stress corrosion will require that an engineering analysis be performed to determine proper
9 corrective action. Specific corrective actions will be implemented in accordance with the Duke Quality
9 Assurance Program.

9 **Timing of New Program or Activity** - Following issuance of renewed operating licenses for Oconee
9 Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of
9 Oconee Unit 1).

9 **Regulatory Basis** - Application [Reference 1] and Final SER [Reference 2].

9 18.2.7 REACTOR COOLANT PUMP MOTOR OIL COLLECTION SYSTEM
9 INSPECTION

9 **Purpose** - The purpose of the Reactor Coolant Pump Motor Oil Collection System Inspection will be to
9 characterize the loss of material due to general and localized corrosion of the carbon steel, copper alloy
9 and stainless steel components in the Reactor Coolant Pump Motor Oil Collection System that may
9 periodically be exposed to water.

9 **Scope** - The results of this inspection will be applicable to the components in the system, particularly the
9 lower portions of the system, with the potential to be exposed to water. Each Oconee unit has four
9 Reactor Coolant Pump Oil Collection Tanks for a total population of twelve at Oconee.

9 **Aging Effects** - The inspection will determine the existence of loss of material due to general and galvanic
9 corrosion for the carbon steel component materials and pitting and crevice corrosion for the carbon steel,
9 copper alloys and stainless steel component materials as a result of periodic exposure to water.

9 **Method** - An inspection of the Reactor Coolant Pump Motor Oil Collection System Tanks will determine
9 whether loss of material due to general and localized corrosion will be an aging effect of concern for the
9 period of extended operation. The evidence gained from the tank examination will be indicative of the
9 condition of all materials in the lower portion of the system.

9 A visual examination on the bottom half of the interior surface of the tank will be performed to determine
9 the presence of corrosion. The visual examination will also serve to characterize any instances of
9 corrosion, both general and localized. A volumetric examination will then be conducted on any
9 problematic areas to determine the condition of the lower portions of the tank that is a leading indicator
9 of the other susceptible components.

9 **Sample Size** - The inspection will include one of the twelve Reactor Coolant Pump Motor Oil Collection
9 System Tanks. The collection tank chosen for inspection will be based on any higher frequency that
9 water has been observed in the oil as well as accessibility and radiological concerns. [Reference 7]

9 **Industry Code or Standards** - No code or standard exists to guide or govern this inspection.

9 **Frequency** - The Reactor Coolant Pump Motor Oil Collection System Inspection is a one-time
9 inspection.

9 **Acceptance Criteria** - Any indication of loss of material will be documented and the need for further
9 analysis determined. No unacceptable loss of material will be permitted, as determined by engineering

analysis. Component wall thickness acceptability will be judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to various forms of corrosion will require that an engineering analysis be performed to determine proper corrective action. Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem Investigation Process will apply to all structures and components within the scope of the Reactor Coolant Pump Motor Oil Collection System Inspection.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.8 SMALL BORE PIPING INSPECTION

Purpose - The purpose of the Small Bore Piping Inspection will be to validate that service- induced weld cracking is not occurring in the small bore Reactor Coolant System piping that does not receive a volumetric examination under ASME Section XI.

Scope - The scope of Small Bore Piping Inspection includes the Oconee inservice inspection Class A piping welds in lines less than 4 inch nominal pipe size including pipe, fittings, and branch connections.

Aging Effects - The aging effect being investigated is cracking of piping welds which may not be fully managed by the current ASME Section XI examinations. For Duke, these inspections are driven by the consequences of small bore piping failures rather than a lack of confidence in the current inservice inspection techniques to manage aging. In many instances, small bore piping cannot be isolated from the Reactor Coolant System and a leak could lead to a small break loss of coolant accident and plant shutdown.

Method - Selected inspection locations will receive either a destructive or non-destructive examination that permits inspection of the inside surface of the piping.

Sample Size - Pipe, fittings, and branch connections over the entire small bore size range will be considered for inspection. The total population of welds will be determined by summing the number of welds found in scope. To determine the inspection locations from this total population of welds, risk-informed approaches will be used to identify locations most susceptible to cracking. Susceptibility will be determined either qualitatively (i.e., based on site and industry experience, evaluation of current ASME Section XI inspection requirements and results, and any applicable regulatory initiatives) or quantitatively, or both. The consequences of weld failure, without respect to susceptibility, also will be evaluated to identify the most safety significant piping welds. After the evaluation of susceptibility and consequences, a list of potential inspection locations will be developed. Actual inspection locations will be selected based on physical accessibility, exposure levels, and the likelihood of meaningful results if a non- destructive technique is employed.

Industry Code or Standards - No code or standard exists to guide or govern this inspection. ASME Section XI provides rules for this piping, but not for volumetric or destructive examination. If destructive examination is employed, the Section XI rules for Repair and Replacement will be used to return piping to its original condition.

Frequency - The Small Bore Piping Inspection is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of cracking of piping welds as determined by engineering analysis.

Corrective Action - Any unacceptable indication of cracking of piping welds requires an engineering analysis be performed to determine proper corrective action.

Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.9 TREATED WATER SYSTEMS STAINLESS STEEL INSPECTION

Purpose - The purpose of the Treated Water Systems Stainless Steel Inspection will be to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components that could be occurring within several Oconee treated water systems.

Scope - The results of this inspection will be applicable to the stainless steel piping and valves in portions of several Oconee treated water systems which are exposed to treated or potable water falling under separate guidelines from the Chemistry Control Program and the state of South Carolina. The stainless steel components may experience aging that is not monitored by current plant programs. The focus on this inspection will be on a representative sample from each of the two treated water groups. The results of the inspections in each group will be an indicator of the condition of all of the stainless steel components in the systems within that group. The systems containing the stainless steel piping and valves under consideration are:

- Chemical Addition System (caustic addition portion containing demineralized water)
- Component Cooling System (the stainless steel Containment penetration portion on Unit 2 only containing demineralized water)
- Chilled Water System (containing potable water)
- Demineralized Water System (Containment penetration portion containing demineralized water)
- Diesel Jacket Cooling Water System (containing demineralized water)
- Liquid Waste Disposal System (Containment penetration portion containing demineralized water)
- SSF Drinking Water System (containing potable water)
- SSF Sanitary Lift System (containing potable water)

Aging Effects - The inspection will determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping and valves.

Method - A volumetric examination of a length of the susceptible piping locations will be conducted for this inspection. This examination will include a stainless steel weld and heat affected zone since this is a more likely location for stress corrosion cracking to occur. In addition to the volumetric examination, a visual examination of the interior of a valve will be conducted to determine the presence of pitting corrosion.

Sample Size - Portions of stainless steel piping and valves, as applicable, for each of the two groups of system components will be inspected. If in the Demineralized Water System no parameters exist that would distinguish among the four Containment penetrations, one of the three, 4-inches nominal pipe size, Containment penetrations will be inspected. A stainless steel weld at one Containment isolation valve

9 along with piping and weld between the isolation valve and the containment penetration schedule
9 transition point will be volumetrically examined. In addition, one valve will be disassembled for an
9 internal visual examination.

9 In the SSF Drinking Water System, a one-foot section of 1-inch nominal pipe size piping will be
9 volumetrically examined upstream of valve PDW-72. In addition, one valve will be disassembled in the
9 license renewal portion of this system for an internal visual inspection.

9 **Industry Code and Standards** - No code or standard exists to guide or govern this inspection. Component
9 wall thickness acceptability will be judged in accordance with the Oconee component design code of
9 record.

9 **Frequency** - The Treated Water Systems Stainless Steel Inspection is a one-time inspection.

9 **Acceptance Criteria or Standards** - No unacceptable indication of loss of material due to pitting corrosion
9 or cracking due to stress corrosion as determined by engineering analysis.

9 **Corrective Action** - Any unacceptable loss of material due to of pitting corrosion or stress corrosion
9 cracking requires an engineering analysis be performed to determine potential impact on component
9 intended function. Specific corrective actions will be implemented in accordance with the Problem
9 Investigation Process. The Problem Investigation Process will apply to all structures and components
9 within the scope of the Treated Water Systems Stainless Steel Inspection.

9 **Timing of New Program or Activity** - Following issuance of renewed operating license for Oconee Nuclear
9 Station, this inspection will be completed by February 6, 2013 (the end of the initial license term for
9 Oconee Unit 1).

9 **Regulatory Basis** - Application [Reference 1] and Final SER [Reference 2].

18.3 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

18.3.1 ALLOY 600 AGING MANAGEMENT PROGRAM

Purpose - The purpose of the Oconee Alloy 600 Aging Management Program will be to manage cracking due to primary water stress corrosion cracking (PWSCC) of Alloy 600 and Alloy 82/182 locations, including the Alloy 82/182 cladding in the hot leg flowmeter element, for the period of extended operation.

Scope - The results of the Alloy 600 Aging Management Program will be applicable to the Alloy 600 material and Alloy 82/182 weld material in the Oconee Reactor Coolant System, including the hot leg flowmeter element. The scope does not include steam generator tubes, sleeves, and plugs.

Aging Effects - The applicable aging effect for the scope of the Alloy 600 Aging Management Program is primary water stress corrosion cracking (PWSCC) of Alloy 600 components and Alloy 82/182 weld metal in the Reactor Coolant System at Oconee.

Method - The exact inspection method will be dependent on the geometry of the inspection locations. Inspection methods will involve a combination of surface and volumetric examinations, which may include eddy current testing, ultrasonic testing, and radiography.

Sample Size - To determine the initial inspection locations, the Oconee Alloy 600 Aging Management Program will, first, complete a susceptibility study of Alloy 600 components and Alloy 82/182 weld locations in the Reactor Coolant System. Upon completion and validation of this susceptibility study, the top five locations will have detailed inspection plans developed and implemented to monitor the condition of these locations. Monitoring the most susceptible locations will bound the Alloy 600 component locations and the Alloy 82/182 weld locations that are not inspected. The five most susceptible locations are the CRDM nozzles at Oconee Unit 2, the pressurizer heater sleeves at Oconee Unit 1, the pressurizer level taps and safe ends at Oconee Unit 3, and the pressurizer vent nozzle at Oconee Unit 3.

Industry Code or Standards - ASME Section XI.

Frequency - The frequency of subsequent inspections will be based on findings of the initial inspections. An analysis will be completed at each of the selected locations that will determine crack propagation rates. The time for an indication to grow from a newly initiated indication to a through wall crack will be used to determine the inspection frequency.

Acceptance Criteria or Standard - Acceptance criteria for identified flaws will be based on crack propagation rates, which vary from location to location based on the calculated residual and operating stresses for the particular location using approved fracture mechanics techniques. In past inspections, after measuring the depth of the indications, small cracks have been allowed to remain in service without immediate repair when the calculated crack growth rate plus the measured depth of the indication predicted no through wall leak (or other acceptance criteria agreed to by the NRC) will occur prior to corrective action being taken or the crack otherwise being dispositioned.

Corrective Action - Corrective actions will be developed and implemented on a case-by-case basis at Oconee depending on the nature of the inspection findings. Either a complete replacement or a repair in accordance with ASME Section XI may be appropriate for some locations. Taking no immediate action on the indication and monitoring with further inspections may also be appropriate.

Both the sample size and number of locations will be re-evaluated following the completion of each inspection with documentation of these re- evaluations completed on an annual basis once the inspections begin. Additional inspection locations may be added to the list based on a qualitative assessment of risk.

Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, the initial inspection of selected locations will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis - Application [Reference 1], Duke Response to RAIs 4.3.1-1, -2, -3, -4, -5, and -6 [Reference 8], and Final SER [Reference 2].

18.3.2 CHEMISTRY CONTROL PROGRAM

The primary objective of the Oconee Chemistry Control Program is to protect the integrity, reliability, and availability of plant equipment and components by minimizing corrosion in fluid systems. To ensure the best protection is provided, reactor coolant water quality specifications are based upon the current revision of the EPRI PWR Primary Water Chemistry Guidelines and vendor recommendations as appropriate [UFSAR Section 5.2.1.7, "Water Chemistry"]. Secondary chemistry specifications are based upon the recommendations in the current revision of the EPRI PWR Secondary Water Chemistry Guidelines.

For component cooling water, Oconee utilizes a modified chromate-phosphate treatment recommended by Babcock & Wilcox Co., the Oconee nuclear steam supply system vendor, as the basis for the chemistry control specifications for the component cooling system. For the SSF diesel jacket water cooling system, Oconee utilizes the industry-standard diesel jacket water cooling treatment method (sodium nitrite/borax/tolytriazole).

The Oconee SSF Fuel Oil surveillances are governed by Oconee Technical Specifications [ITS SR 3.10.1.8 and ITS 5.5.14]. The applicable ASTM standard is ASTM D975 Standard, "Standard Specification for Diesel Fuel Oils."

Acceptance criteria for each monitored parameter have been established and are described in the applicable section of the Oconee Chemistry Manual. In the event the acceptance criteria are not met, then specific corrective actions will be implemented in accordance with the Problem Investigation Process.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.3 CONTAINMENT INSERVICE INSPECTION PLAN

The Oconee Containment Inservice Inspection Plan implements the requirements of 10 CFR 50.55a (61 Federal Register 41303, dated August 8, 1996) and the 1992 Edition with the 1992 Addenda of Subsection IWE, "Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants," and Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants." The examinations are performed to the extent practicable within the limitations of design, geometry and materials of construction of the component. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

The Containment Inservice Inspection Plan for each inservice inspection interval of the license renewal term will:

1. Implement the examination requirements of either:
   a. Section 50.55a (61 Federal Register 41303, dated August 8, 1996) and the 1992 Edition with the 1992 Addenda of Subsection IWE, "Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants," and Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants" with the limitation listed in paragraph (b)(2)(vi) and the modifications listed in paragraphs (b)(2)(ix) and (b)(2)(x) of Section 50.55a, or
   b. the edition of the ASME Section XI Code required by Section 50.55a(b) prior to the start of the 120-month inservice inspection interval, or
   c. another edition of ASME Section XI provided an appropriate evaluation is performed;
2. Comply with Section 50.55a, except that if an examination required by the Code or Addenda is determined to be impractical, a relief request will be submitted to the Commission in accordance with the requirements contained in Section 50.55a, for Commission evaluation.

18.3.4 CONTROL ROD DRIVE MECHANISM NOZZLE AND OTHER VESSEL CLOSURE PENETRATIONS INSPECTION PROGRAM

Purpose - The purpose of the Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program is to verify the assumptions made in the BWOG safety evaluation of the susceptibility and consequence of primary water stress corrosion cracking in B&W-designed control rod drive mechanism (CRDM) nozzles by gathering additional inspection information in order to better characterize PWSCC.

Scope - The scope of the program includes reactor vessel closure head CRDM nozzles for all three units and the Oconee Unit 1 thermocouple penetrations.

Aging Effects - The applicable aging effect is PWSCC of Alloy 600 nozzles with partial penetration welds that cause high circumferential residual stresses on the inner diameter of the nozzles opposite the welds.

Method - Eddy current inspection will be utilized for detection. Eddy current, ultrasonic, and liquid penetrate may be used for sizing, as appropriate.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - The inspection frequency is dependent on plant-specific, B&WOG, and industry-wide inspection results. Future inspections will be established upon review of these inspection results.

Acceptance Criteria or Standard - Axial flaws detected during inspection will be analyzed and evaluated using the NUMARC acceptance criteria that were approved by the NRC in their Safety Evaluation dated November 19, 1993. Circumferential flaws will be analyzed and addressed with the NRC on a case-by-case basis [Reference 9].

Corrective Action - Flaws that cannot be justified for continued service by analysis will be repaired in accordance with ASME Section XI. Flaws that can be justified for continued service become time-limited aging analyses and are addressed by the Oconee Thermal Fatigue Management Program. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Duke response to NRC Generic Letter 97-01 [Reference 10], Application [Reference 1] and Final SER [Reference 2].

18.3.5 CRANE INSPECTION PROGRAM

Purpose - The purpose of the Crane Inspection Program is to provide periodic inspections and preventive maintenance on Oconee cranes and hoists. A subset of the many inspection activities performed under the auspices of the Crane Inspection Program is the inspection of the structural components.

Scope - Structural components associated with the following cranes and hoists are included in the Crane Inspection Program for license renewal:

Building	**Crane**
Auxiliary Building	Spent Fuel Bay Crane
	Spent Fuel Pool Fuel Handling Crane
	Hoists located over safety-related equipment
Keowee	270 Ton Crane
	Intake Hoist
	Hoists located over safety-related equipment
Reactor Building	Polar Crane
	2 Ton CRDM Service Crane
	Main Fuel Handling Bridge
	Equipment Hatch Hoist
	Hoists located over safety-related equipment
Turbine Building	Pump Aisle Crane
	Turbine Aisle Crane
	Turbine Aisle Auxiliary Crane
	Heater Bay Crane
	Hoists located over safety-related equipment
Standby Shutdown Facility	Hoists located over safety-related equipment

A list of hoists located over safety-related equipment is maintained at Oconee.

Aging Effects - The applicable aging effect is loss of material due to corrosion of the steel components.

Method - The program requires visual inspections of cranes and hoists within the scope.

Industry Code or Standard - ANSI B30.2.0 [Reference 11] for cranes and ANSI B30.16 [Reference 12] for hoists.

Frequency - Each crane and hoist is subject to several inspections. The inspection frequencies for the cranes are based on the guidance provided by ANSI B30.2.0. The inspection frequencies for hoists are based on guidance provided by ANSI B30.16.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material as determined by the accountable engineer.

Corrective Action - Items which do not meet the acceptance criteria are repaired or replaced. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - 29 CFR Chapter XVII, Section 1910.179 [Reference 13], Application [Reference 1] and Final SER [Reference 2].

18.3.6 DUKE POWER FIVE-YEAR UNDERWATER INSPECTION OF HYDROELECTRIC DAMS AND APPURTENANCES

Purpose - The purpose of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances is to inspect the structural integrity of the Keowee intake structure, spillway, and powerhouse.

Scope - The scope of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances includes:

- Keowee Intake - trashracks, support steel and concrete
- Spillway - concrete
- Powerhouse - concrete

Aging Effects - The applicable aging effects include loss of material due to corrosion for steel components and loss of material, cracking, and change in material properties of concrete components.

Method - The program requires visual examinations of external surfaces. The examination of external surfaces covers the Keowee Intake, Spillway, and Powerhouse concrete surfaces exposed to water. The concrete structures are inspected from the foundation to the free water surface. [Reference 14]

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed once every five years. The inspection frequency is consistent with the periodicity of inspections performed by Duke Energy in accordance with FERC requirements for maintaining other components of the structures. (See Section 18.3.8, "Federal Energy Regulatory Commission (FERC) Five Year Inspections").

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material, cracking, or change in material properties as determined by the accountable engineer.

Corrective Action - Areas which do not meet the acceptance criteria are evaluated by the accountable engineer. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances.

Regulatory Basis - 18 CFR Part 12, Safety of Water Power Project and Project Works, Application [Reference 1] and Final SER [Reference 2].

18.3.7 ELEVATED WATER STORAGE TANK CIVIL INSPECTION

Purpose - The purpose of the Elevated Water Storage Tank Civil Inspection is to provide a visual examination of the interior surfaces of the tank and associated components to ensure their structural integrity.

Scope - The scope of the program includes the interior surfaces of the Elevated Water Storage Tank and associated components.

Aging Effects - The applicable aging effect is loss of material due to corrosion.

Method - The program requires visual examinations of internal surfaces in accordance with station procedures. The inspection covers 100% of the interior tank surfaces. [Reference 14]

Industry Code or Standard - NFPA 25, Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems.

Frequency - Inspections are performed once every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material due to corrosion as determined by the accountable engineer.

Corrective Action - Items that do not meet the acceptance criteria are evaluated for continued service, monitored, or corrected. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.8 FEDERAL ENERGY REGULATORY COMMISSION (FERC) FIVE YEAR INSPECTIONS

Inspections of the Keowee River Dam; Little River Dam; Little River Dikes A, B, C, and D; Oconee Intake Canal Dike; Keowee Spillway and Left Abutment, Keowee Intake and Powerhouse are performed in accordance with the requirements contained in 18 CFR Part 12, Safety of Water Power Projects and Project Works [Reference 15].

18.3.9 FLOW ACCELERATED CORROSION PROGRAM

Purpose - The purpose of the Flow Accelerated Corrosion Program is to manage loss of material for the component locations in the Feedwater System and Main Steam System that have been identified as being susceptible to flow accelerated corrosion.

Scope - The portion of the overall program credited for license renewal includes the components in the Feedwater System between the main control valves, bypass block valves, and the steam generator, and a small section of Main Steam System piping downstream of the Emergency Feedwater pump turbine steam supply control valve.

Aging Effects - The aging effect of concern is loss of material of carbon steel components due to flow accelerated corrosion under certain relevant conditions. Relevant conditions include physical parameters such as fluid temperature, fluid (steam) quality, fluid velocity, fluid pH, mechanical component geometry and piping configuration. An analytical review process is used to determine susceptible locations based on these types of relevant conditions.

Method - The focus of the program is on the carbon steel components in the more susceptible locations within these systems. Over seventy total inspection locations exist for the three units' Feedwater Systems and ten separate inspection locations exist for the three units' Main Steam Systems. Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing and radiography. Also visual examination is used when access to interior surfaces is allowed by component design.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. However, the program follows the basic guidelines or recommendations provided by EPRI Document NSAC- 202L.

Component wall thickness acceptability is judged in accordance with the Oconee component design code of record.

Frequency - Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experiences.

Acceptance Criteria - Using inspection results and including a safety margin, the projected component wall thickness at the time of the next plant outage must be greater than the allowable minimum wall thickness under the component design code of record.

Corrective Action - If the calculated component wall thickness at the time of the next outage is projected to be less than the allowable minimum wall thickness with safety margin under the component design code of record, then the component will be repaired or replaced prior to system start-up. The as-inspected component can also be justified for continued service through additional detailed engineering analysis. Specific corrective actions are implemented in accordance with approved station processes, including work orders, modifications and the Problem Investigation Process.

Regulatory Basis - Duke response to Bulletin 87-01 [References 16 and 17] and Duke response to Generic Letter 89-08 [References 18 and 19], Application [Reference 1] and Final SER [Reference 2].

18.3.10 FLUID LEAK MANAGEMENT PROGRAM

Purpose - The purpose of the Fluid Leak Management Program is to ensure identification of leaks followed by timely investigation and repair. When boric acid leakage is involved, this program describes activities to identify the source of leakage and to evaluate subsequent corrosion degradation of associated piping, structures and components. This program includes focus on small leaks that generally occur below technical specification limits for operational leakage.

Scope - The results of the program are applicable to mechanical components and structural components fabricated from aluminum, brass, bronze, copper, galvanized steel, carbon steel and low alloy steel that are located in proximity to borated systems. Electrical equipment located in proximity to borated systems is also included. This program addresses equipment both inside and outside the Reactor Building. Bolted closures such as manways and flanged connections of systems containing dissolved boric acid are also included.

Aging Effects - Two of the conditions evaluated by the Fluid Leak Management Program are loss of material from components due to boric acid corrosion of the carbon steel and low alloy steel and boric acid intrusion into electrical equipment.

Method - Visual inspections are performed on external surfaces in accordance with plant procedures. Plant personnel look for leakage from both insulated and uninsulated components, as well as general corrosion of a component that may result from leakage. Plant personnel look for borated water leakage indicators such as discoloration or accumulated residue on surfaces such as insulation materials or floors. Possible intrusion of boric acid into electrical equipment is evaluated.

Industry Code or Standard - ASME Section XI and Generic Letter 88-05 [Reference 20].

Frequency - Reactor Building inspections are performed each refueling outage. Inspections of the Auxiliary Building are performed at a minimum as frequently as the Reactor Building is inspected. [Reference 21]

Acceptance Criteria or Standard - The Fluid Leak Management Program defines actions to achieve the following acceptance criteria:

1. Insulated, non-insulated or inaccessible components within borated water systems will have external leakage, and
2. Components within scope with degradation resulting from external leakage from borated water systems will be evaluated by engineering.

Corrective Action - When the programmatic activities described in the Fluid Leak Management Program lead to detection of an unacceptable condition, the following corrective actions are required:

1. Locate leak source and areas of general corrosion.
2. Evaluate pressure-retaining components suffering wall loss for continued service or replacement.
3. Evaluate other affected components such as supports and other structural members for continued service, repair or replacement.

Specific corrective actions are implemented in accordance with the Fluid Leak Management Program or the Problem Investigation Process. These programs apply to all structures and components within the scope of the Fluid Leak Management Program.

Regulatory Basis - ASME Section XI, Examination Category B-P, All Pressure Retaining Components, Examination Category C-H, All Pressure Retaining Components; Examination Category D-A, Systems in Support of Reactor Shutdown Function; Examination Category D-B, Systems in Support of Emergency Core Cooling, Containment Heat Removal, Atmospheric Cleanup, and Reactor Residual Heat Removal and Examination Category D-C, Systems in Support of Residual Heat Removal from Spent Fuel Storage Pool; Duke commitments in response to NRC Generic Letter 88-05 [Reference 22], Application [Reference 1], Final SER [Reference 2], and Duke letter [Reference 23].

18.3.11 HEAT EXCHANGER PERFORMANCE TESTING ACTIVITIES

The following heat exchangers in the scope of license renewal have heat transfer as a component intended function that could be impacted by fouling. Each of these heat exchangers has raw water from the Low Pressure Service Water System:

- the decay heat removal coolers in the Low Pressure Injection System,
- the Reactor Building cooling units in the Reactor Building Cooling System, and
- the component coolers in the Component Cooling System
- the Standby Shutdown Facility HVAC coolers in the Standby Shutdown Facility Auxiliary Service Water System.

Periodic testing is completed each refueling outage for the decay heat removal coolers the Reactor Building cooling units. Performance testing for these heat exchangers will provide assurance that the components are capable of adequate heat transfer required to meet system and accident load demands. Heat removal capacity is determined and compared to test acceptance criteria established by the accountable engineer and to previous test results for the decay heat removal coolers and the Reactor Building cooling units. If an adverse trend in heat removal is found, then corrective actions will be taken.

The Standby Shutdown Facility HVAC coolers are normally in service because they are required for SSF system operability per ITS 3.10.1.D. The component coolers are normally in service because they are required to support normal plant operation. Accident load demands for these coolers are not greater than normal operation. Thus, heat removal capacity calculations are not performed for these coolers. Rather, flowrates through these coolers are monitored on a periodic basis. The Standby Shutdown Facility HVAC cooler flowrate is monitored twice per day. The component cooler flowrate is recorded on a

refueling basis during performance testing. If an adverse trend in flowrate is found, then corrective actions will be taken.

If the heat exchangers fail to perform adequately, then corrective actions such as cleaning are undertaken. Specific corrective actions are implemented in accordance with the Problem Investigation Process. This program applies to all structures and components within the scope of the Heat Exchanger Performance Testing Activities.

The continued implementation of the Heat Exchanger Performance Testing Activities provides reasonable assurance that the heat exchangers will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2]. Also, the activities credited here for license renewal for the SSF HVAC coolers, Decay Heat Removal coolers and the Reactor Building cooling Units are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 24, 25, 26, 27, and 28].

18.3.12 INSERVICE INSPECTION PLAN

The Oconee Inservice Inspection Plan, implements the requirements of 10 CFR 50.55a for Class 1, 2, and 3 components and Class 1, 2, 3, and MC component supports. The examinations are performed to the extent practicable within the limitations of design, geometry and materials of construction of the component. The period of extended operation for Oconee will contain the 5th and 6th ten-year inservice inspection intervals. The Oconee Inservice Inspection Plan for each of these two inservice inspection intervals will:

1. Include compliance with Appendix VII, Qualification of Nondestructive Examination Personnel for Ultrasonic Examination;
2. Include compliance with Appendix VIII, Performance Demonstration for Ultrasonic Examination Systems;
3. Implement the Subsection IWB examination requirements of either (a) the 1989 Edition of ASME Section XI, or (b) the edition of the ASME Section XI Code required by Section 50.55a(b), or (c) another edition of ASME Section XI provided an appropriate evaluation is performed;
4. Comply with Section 50.55a except that if an examination required by the Code or Addenda is determined to be impractical, then a relief request will be submitted to the Commission in accordance with the requirements contained in Section 50.55a, for Commission evaluation; and
5. Include examination of pressurizer heater bundle welds in accordance with Examination Category B-E (or equivalent).

The Inservice Inspection Plan is credited for license renewal with managing certain aging effects associated with Reactor Coolant System pressure retaining components, their integral attachments, and other structural components within the jurisdiction of ASME Section XI. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

In addition, for Cast Austenitic Stainless Steel (CASS) Class 1 components when conditions are detected during these inservice inspections that exceed the allowable limits of ASME Section XI, engineering evaluations of either detected or postulated flaws shall be carried out using material properties and acceptance criteria applicable to the evaluation procedures presented in IWB-3640. More favorable material properties and acceptance criteria may be used, if justified, on a case-by-case basis [Reference 1, Volume III, Exhibit A, Chapter 4, and Reference 2].

18.3.13 INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS

The Inspection Program for Civil Engineering Structures and Components is intended to meet the requirements of 10 CFR 50.65, Requirements for monitoring the effectiveness of maintenance at nuclear power plants (the Maintenance Rule). This program:

1. monitors and assesses mechanical components, civil structures and components and their condition in order to provide reasonable assurance that they are capable of performing their intended functions in accordance with the current licensing basis;
2. monitors degradation of caulking, sealants and waterstops in the Auxiliary Building and Standby Shutdown Facility which may include but is not limited to water in-leakage, leaching, peeling paint, or discoloration of the concrete; and
3. includes nuclear safety-related structures which enclose, support, or protect nuclear safety- related systems and components and non-safety related structures whose failure may prevent a nuclear safety-related system or component from fulfilling its intended function.

NEI 96-03, Industry Guideline for Monitoring the Condition of Structures at Nuclear Power Plants, has been used as guidance in the preparation of the Inspection Program for Civil Engineering Structures and Components.

Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Inspection Program for Civil Engineering Structures and Components.

18.3.14 INSULATED CABLES AND CONNECTIONS AGING MANAGEMENT PROGRAM

Purpose - The purpose of the Insulated Cables and Connections Aging Management Program is to provide reasonable assurance that the license renewal intended functions of insulated cables and connections will be maintained consistent with the current licensing basis through the period of extended operation.

Scope - The Insulated Cables and Connections Aging Management Program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the Reactor Buildings, Auxiliary Buildings, Turbine Buildings, Standby Shutdown Facility, Keowee, in conduit and direct-buried, which could be subject to applicable aging effects from heat, radiation or moisture. This program does not include insulated cables and connections that are in the Environmental Qualification program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment. An applicable aging effect is an aging effect that, if left unmanaged, could result in the loss of a component's license renewal intended function in the period of extended operation.

Aging Effects - Change in material properties of the conductor insulation is the applicable aging effect. The changes in material properties managed by this program are those caused by severe heat, radiation or moisture - conditions that establish an adverse, localized environment, which include energized medium-voltage cables exposed to significant moisture.

Method - The methods used are different for accessible insulated cables and connections and for inaccessible or direct-buried medium-voltage cables, which cannot be visually inspected.

9 Accessible insulated cables and connections installed in adverse, localized environments will be visually
9 inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface
9 contamination. Surface anomalies are indications that can be visually monitored to preclude the
9 conductor insulation applicable aging effect. In addition, water collection in manholes containing
9 in-scope, medium-voltage cables will be monitored to prevent the cables from being exposed to significant
9 moisture.

9 Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage
9 will be tested. The specific type of test performed will be determined prior to each test. Significant
9 moisture exposure is defined as periodic exposures to moisture that last more than a few days (e.g., cable
9 in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and
9 drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for
9 more than twenty-five percent of the time. These definitions apply to cables for which no specific design
9 characteristics are known. The moisture and voltage exposures described as significant in these definitions
9 are not significant for medium-voltage cables that are designed for these conditions.

9 **Sample Size** - Samples may be used for this program. If used, an appropriate sample size will be
9 determined prior to the inspection or test.

9 **Industry Codes and Standards** - EPRI TR-109619, Guideline for the Management of Adverse Localized
9 Equipment Environments will be used as guidance in implementing this program.

9 **Frequency** - Accessible insulated cables and connections installed in adverse, localized environments will
9 be inspected at least once every 10 years. Water collection in manholes containing in-scope,
9 medium-voltage cables will be monitored at a frequency adequate to prevent the cables from being
9 exposed to significant moisture.

9 Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage
9 will be tested at least once every 10 years.

9 **Acceptance Criteria or Standard** - The acceptance criteria is different for accessible insulated cables and
9 connections and for inaccessible or direct-buried medium-voltage cables.

9 For accessible insulated cables and connections installed in adverse, localized environments, the
9 acceptance criteria is no unacceptable, visual indications of jacket surface anomalies, which suggest that
9 conductor insulation applicable aging effect may exist, as determined by engineering evaluation. An
9 unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a
9 loss of the license renewal intended function. In-scope, medium-voltage cables in manholes found to be
9 exposed to significant moisture will be tested as described for inaccessible cables under Method,
9 Frequency and Acceptance Criteria of this program.

9 For inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant
9 voltage, the acceptance criteria for the test will be defined by the specific type of test to be performed and
9 the specific cable to be tested.

9 **Corrective Action** - Further investigation by engineering will be performed on accessible and inaccessible
9 insulated cables and connections when the acceptance criteria is not met in order to ensure that the license
9 renewal intended functions will be maintained consistent with the current licensing basis. Corrective
9 actions may include, but are not limited to, testing, shielding or otherwise changing the environment,
9 relocating or replacement. Specific corrective actions will be implemented in accordance with the Problem
9 Investigation Process. The Problem Investigation Process applies to all structures and components within
9 the scope of the Insulated Cables and Connections Aging Management Program. When an unacceptable

condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible cables and connections.

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, the initial inspections and tests will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis - Duke response to SER Open Item 3.9.3 [Reference 29] and Final SER [Reference 2].

18.3.15 KEOWEE OIL SAMPLING PROGRAM

Purpose - The purpose of the Keowee Oil Sampling Program is to monitor and control the water contamination levels in the Governor Oil System to preclude loss of material for the carbon steel and stainless steel components in the scope of license renewal. In addition, the Keowee Oil Sampling Program manages loss of material of the stainless steel subcomponents in the Turbine Guide Bearing Oil System by monitoring the Turbine Guide Bearing Oil System for water contamination.

Scope - The scope of the Keowee Oil Sampling Program includes all carbon steel and stainless steel components within the scope of license renewal in the Governor Oil System and the turbine guide bearing oil coolers, the only stainless steel component of concern in the Turbine Guide Bearing Oil System. This program contains elements that cover all four Keowee oil systems and, as such, is intended to cover a broader scope than is being credited for license renewal.

Aging Effects - Water contamination in the Governor Oil System can expose the carbon steel and stainless steel components to conditions conducive to loss of material due to various forms of corrosion. Water contamination in the Turbine Guide Bearing Oil System is evidence of leakage of the Turbine Guide Bearing Oil Cooler from loss of material due to microbiologically influenced corrosion of the stainless steel components in the raw water environment of the shell side of the cooler. Monitoring and controlling water contamination precludes this applicable aging effect in the Governor Oil System and manages this applicable aging effect in the Turbine Guide Bearing Oil Coolers.

Method - The Keowee Oil Sampling Program requires that the Governor Oil System Sump and Turbine Guide Bearing Oil System reservoirs be sampled for the presence of water contamination. Results of the analysis are monitored and trended.

Industry Codes or Standards - ASTM D95-83, Water in Petroleum and Bitumens, provides guidance for the testing of the oil sample.

Frequency - Oil samples are taken and analyzed every six months.

Acceptance Criteria or Standard - No water contamination in excess of 0.1% water by volume is the limit for water contamination in the Governor Oil System and Turbine Guide Bearing Oil System.

Corrective Action - If water contamination levels exceed the acceptance criteria, the accountable engineer will be notified and the source of the water contamination will be located and corrected. The contaminated oil will be sent to the plant oil purifier to remove the water and returned to the system. Specific corrective actions are made in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.16 PENSTOCK INSPECTION

Purpose - The purpose of the Penstock Inspection is to ensure that the structural integrity of the Keowee Penstock will be maintained.

Scope - The scope of the Penstock Inspection includes both the steel lined and unreinforced concrete lined sections of the Keowee Penstock.

Aging Effects - The applicable aging effects include loss of material, cracking, and change in material properties for the unreinforced concrete lined section and loss of material for the steel lined section of the Keowee Penstock.

Method - The Penstock Inspection requires visual examination of the interior surface of the Keowee Penstock.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed when the Keowee Penstock is dewatered during outages, which is at least every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of aging effects as identified by the accountable engineer.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated by the accountable engineer for continued service or corrected by repair or replacement. Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Penstock Inspection.

Regulatory Basis - 18 CFR Part 12, Safety of Water Power Projects and Project Work.

18.3.17 PREVENTIVE MAINTENANCE ACTIVITIES

18.3.17.1 Borated Water Storage Tank Internal Coatings Inspection

A visual inspection of the internal coating of the tank will be performed every third refueling outage with the borated water removed from the tank. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Borated Water Storage Tank Internal Coating Inspection.

18.3.17.2 Chilled Water Refrigeration Unit Preventive Maintenance Activity

For the portions of the exposed to raw water in the condensing heat exchangers of the refrigeration unit, system parameters of the entire refrigeration unit are monitored during operation to provide evidence of fouling and loss of material. Parameters monitored are monitored quarterly and include inlet and outlet temperatures along with refrigerant pressures. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Chilled Water System Refrigeration Unit Preventive Maintenance Activity.

18.3.17.3 Component Cooler Tubing Examination

Eddy current testing of component cooler tubing is performed every other refueling outage. Approximately 100% of the tubing is examined. The acceptance criterion for the inspection is that all tube wall loss indications shall be less than 60% through wall. Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Component Cooler Tubing Examination.

18.3.17.4 Condensate Cooler Tubing Examination

Eddy current testing of condensate cooler tubing is performed every third refueling outage. The most susceptible tubes, those along the perimeter and those at the baffle regions that will experience turbulence due to the baffle geometry (approximately 25% of the tubes), are tested. The acceptance criterion for the inspection is that all wall loss indications must be less than 60% through wall. Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Condensate Cooler Tubing Examination.

18.3.17.5 Condenser Circulating Water System Internal Coatings Inspection

A visual inspection of the interior surfaces of the underground portions of the Condenser Circulating Water System intake and discharge piping is performed every five years. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Condenser Circulating Water System Internal Coatings Inspection.

18.3.17.6 Control Room Ventilation System Examination

A visual inspection of the exterior surfaces of the Control Room Pressurization Filtration System components, including seals, sealants, rubber boots, and flexible collars is performed quarterly. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Control Room Ventilation System Examination.

18.3.17.7 Decay Heat Cooler Tubing Examination

Eddy current testing of the Decay Heat Cooler tubing is performed every fourth refueling outage. All of the inservice stainless steel heat exchanger tubes are examined. The acceptance criterion for the inspection is that all wall loss indications are less than 60% through wall. Tubes with wall loss indications greater than 60% through wall are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Decay Heat Cooler Tubing Examination.

18.3.17.8 Fire Hydrant Flow Test

Fire Hydrant Flow Test is an activity within the Fire Protection Program that was credited in license renewal. (Selected Licensee Commitments apply to other credited portions of the Fire Protection

9 Program.) A flow test of fire hydrants is performed periodically. Specific corrective actions are
9 implemented in accordance with the Problem Investigation Process. The Problem Investigation Process
9 applies to all license- renewal related components within the scope of the Fire Hydrant Flow Test.

9 18.3.17.9 Jacket Water Heat Exchanger Preventive Maintenance Activity

9 System parameters of the entire Diesel Jacket Water Cooling System (i.e., system operating temperatures,
9 pressures, and expansion tank levels) are monitored during diesel engine operation as required by
9 Technical Specification Surveillance Requirement 3.10.1.9. Specific corrective actions are implemented in
9 accordance with the Problem Investigation Process. The Problem Investigation Process applies to all
9 structures and components within the scope of the Jacket Water Heat Exchanger Preventive Maintenance
9 Activity.

9 18.3.17.10 Keowee Turbine Generator Cooling Water System Strainer Inspection

9 A visual inspection of the strainer is performed weekly on the turbine packing box cooler water strainer
9 and bimonthly on the main inlet strainer. Any noticeable sign of loss of material is documented. Specific
9 corrective actions are implemented in accordance with the Problem Investigation Process. The Problem
9 Investigation Process applies to all structures and components within the scope of the Keowee Turbine
9 Generator Cooling Water System Strainer Inspection.

9 18.3.17.11 Main Condenser Tubing Examination

9 Eddy current testing is performed on ten percent of the tubes in one-half of the condenser each refueling
9 outage. Tubes in each half of the condenser are examined every other refueling outage. The acceptance
9 criterion for the examination is that all tubing wall loss indications will be less than 60% through wall.
9 Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify
9 continued service or are plugged. Specific corrective actions are implemented in accordance with the
9 Problem Investigation Process. The Problem Investigation Process applies to all structures and
9 components within the scope of the Main Condenser Tubing Examination.

9 18.3.17.12 Reactor Building Auxiliary Cooler Inspection

9 A pressure test and visual inspection of all of the tubing of one tube bundle (consisting of four coils) is
9 performed each refueling outage. The acceptance criteria are no visible leakage resulting from pressure
9 testing. In addition, any indication of loss of material will be documented and the need for further
9 analysis determined. No unacceptable loss of material will be permitted, as determined by engineering
9 analysis. Specific corrective actions are implemented in accordance with the Problem Investigation
9 Process. The Problem Investigation Process applies to all structures and components within the scope of
9 the Reactor Building Auxiliary Cooler Inspection.

9 18.3.17.13 Reactor Building Cooling Unit Tubing Inspection

9 Each refueling outage or as required by periodic performance testing, tubes are rodded out and visually
9 inspected. In addition, the shell is cleaned and visually inspected. The acceptance criterion is any
9 indication of loss of material will be documented and the need for further analysis determined. No
9 unacceptable loss of material will be permitted, as determined by engineering analysis. Visual inspection
9 of the ductwork and internal supports is performed on the frequency of the performance testing. Specific
9 corrective actions are implemented in accordance with the Problem Investigation Process. The Problem
9 Investigation Process applies to all structures and components within the scope of the Reactor Building
9 Cooling Unit Inspection.

18.3.17.14 Standby Shutdown Facility Diesel Fuel Oil Tank Inspection

A visual inspection of the interior surface of the tank is performed every ten years with the fuel oil removed from the tank. The acceptance criterion is no visual indications of loss of material as determined by Engineering. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Standby Shutdown Facility (SSF) Diesel Fuel Oil Tank Inspection.

18.3.17.15 Standby Shutdown Facility HVAC Coolers Preventive Maintenance Activity

Inlet and outlet temperatures of all three coolers as well as refrigerant conditions are monitored every six months. A visual inspection of the aluminum fins on the air cooling coils is performed every six months. For the water-cooled SSF HVAC condensers, cooling water and air operating temperatures will be within appropriate operating range and refrigerant will be within appropriate specifications. For the air cooling coil, the acceptance criterion is no indications of loss of material of the aluminum fins. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the SSF HVAC Coolers Preventive Maintenance Activity.

Regulatory Bases for the preceding Preventive Maintenance Activities:

- Application [Reference 1].
- W. R. McCollum Jr., (Duke) letter dated December 14, 1998, to Document Control Desk (NRC), Response to NRC letter dated October 29, 1998, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
- M. S. Tuckman (Duke) letter dated September 30, 1999, to Document Control Desk (NRC), Amendment 1 - CLB Changes for 1999, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
- M. S. Tuckman (Duke) letter dated October 15, 1999, to Document Control Desk (NRC), Safety Evaluation Report, Comments and Responses to Open Items and Confirmatory Items, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
- Final SER [Reference 2].

18.3.18 PROGRAM TO INSPECT THE HIGH PRESSURE INJECTION CONNECTIONS TO THE REACTOR COOLANT SYSTEM

Purpose - The purpose of the Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System is to manage the tightness of the interface between the HPI nozzle thermal sleeves and safe ends and to manage the cracking of the piping welds in the normal and emergency HPI portions of the Reactor Coolant System branch lines. This program satisfies the requirements of previous Oconee inspection commitments to the NRC for Generic Letter 85-20 [Reference 30] and IE Bulletin 88-08 [Reference 31], as well as some key ASME Section XI requirements and simplifies the programmatic oversight of these risk-significant welds in the Reactor Coolant System.

Scope - The scope of this program includes the HPI nozzles on the reactor coolant loops and attached Reactor Coolant System piping. The program also applies to the thermal sleeves within the nozzles. It encompasses all Oconee System Piping Class A (not ISI Class A) HPI piping and components with the additions of some welds within Oconee System Piping Class B boundaries (still within ISI Class A scope) being examined in accordance with IE Bulletin 88-08 commitments.

9 The commitments of Oconee letter from Mr. W. R. McCollum, Jr. to U.S. Nuclear Regulatory
9 Commission of January 7, 1998 on Oconee Nuclear Site, Docket Nos. 50-269, -270, -287, Inservice
9 Inspection Program, Third Yen-Year ISI Interval, GL 85-20 Supplemental Information in answer to the
9 NRC letter from David E. LaBarge to Mr. W. R. McCollum of October 23, 1997, High Pressure
9 Injection System Augmented Inservice Inspection Program - Oconee Nuclear Station Units 1, 2, and 3
9 (TAC No. M98454) will continue to apply.

9 **Aging Effects** - Two aging effects are addressed by this program. The first aging effect is the cracking of
9 the base metal or weld metal which could result in a non-isolable Reactor Coolant System Piping leak.

9 The second aging effect is the initiation and growth of gaps between the protective thermal sleeve and the
9 nozzle safe end.

9 **Method** - This program includes the inspection techniques for these locations defined from ASME Section
9 XI, Subsection IWB defined in the Oconee Inservice Inspection Plan. Additional augmented inspections
9 are done using ultrasonic (UT) and dye- penetrant (PT) inspections of the components of the nozzles and
9 piping to detect cracks, and radiographic (RT) inspections to verify no gaps are growing between the
9 thermal sleeve and the safe end.

9 Ultrasonic inspections shall meet the requirements of either Appendix VIII of Section XI of 1992 w/1993
9 addenda ASME, or mockups containing thermal fatigue cracks will be used.

9 **Industry Code or Standard** - ASME Section XI for the detection and engineering evaluation of flaws in
9 the welds.

9 **Frequency** - The frequency of actions under this program are component location-specific. The
9 frequencies are established for each component location by considering the ASME Section XI inspection
9 frequencies in IWB-2400 as well as the frequencies established by Duke regulatory commitments for
9 Generic Letter 85-20 and IE Bulletin 88-08.

9 **Acceptance Criteria or Standard** - For the base metal or weld metal, the acceptance criteria are no flaws in
9 welds and base metal in accordance with ASME Section XI acceptance criteria and no flaws in the nozzle
9 inner radius base metal (which is not required to be inspected under ASME Section XI criteria but which
9 is being inspected under Generic Letter 85-20 commitments in accordance with standards established as a
9 part of the Duke commitment to Generic Letter 85-20).

9 For the protective thermal sleeve and the nozzle safe end, the acceptance criterion is no increase in size of
9 the gaps between the thermal sleeve and safe end.

9 **Corrective Action** - Flaws that can be justified for continued service become time-limited aging analyses
9 and are addressed by the Oconee Thermal Fatigue Management Program. Flaws in weld or base metal
9 that cannot be accepted based on either the geometry screening or the Fracture Mechanics Analysis
9 methods of ASME Section XI are corrected by repair or replacement activities. Unacceptable gaps
9 detected by sleeve RT are corrected by repair or replacement activities. Specific corrective actions will be
9 implemented in accordance with the Duke Quality Assurance Program.

9 **Regulatory Basis** - Application [Reference 1] and Final SER [Reference 2]. Specific Duke-NRC
9 communications with regard to NRC Generic Letter 85-20, IE Bulletin 88-08 and Oconee Inservice
9 Inspection Plan provide the regulatory basis for this program. They are:

9 • W. R. McCollum, Jr., (Duke) letter dated August 6, 1997 to Document Control Desk (NRC),
9 Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, Inservice Inspection
9 Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information.

- W. R. McCollum, Jr., (Duke) letter dated September 10, 1997 to Document control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, Inservice Inspection Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information.
- H. B. Tucker (Duke) letter dated December 29, 1989 to Document Control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, -287, Thermal Stresses in Piping Connected to Reactor Coolant System (NRC Bulletin 88-08).

18.3.19 REACTOR VESSEL INTEGRITY PROGRAM

The Oconee Reactor Vessel Integrity Program consists of the following five interrelated subprograms:

1. Master Integrated Reactor Vessel Surveillance Program,
2. Cavity Dosimetry Program,
3. Fluence and Uncertainty Calculations,
4. Pressure Temperature Limits, and
5. Monitoring Effective Full Power Years.

The Master Integrated Reactor Vessel Surveillance Program is an NRC approved B&WOG program [Reference 32] that complies with requirements for an integrated surveillance program in accordance with Section 50.60, Appendix H. Cavity dosimetry is used as a continuous monitoring device to ensure that the calculated values of reactor vessel fluence are accurate. Reactor vessel fluence and uncertainty calculations are used as input to calculate pressure temperature limits and end-of-life reference temperatures. Pressure temperature limit curves determine the operating region during normal heatup, normal cooldown, and inservice leak and hydrostatic test transients. The calculation of reactor vessel effective full power years is used to ensure that the pressure temperature limits and end-of-life reference temperatures are not violated. These subprograms are described in the following sections.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.19.1 Master Integrated Reactor Vessel Surveillance Program

Duke is a participant in the B&WOG Master Integrated Reactor Vessel Surveillance Program (MIRVP). The MIRVP meets the requirements of Appendix H of 10 CFR Part 50, with regard to integrated surveillance programs (paragraph III.C) and is also an NRC accepted program. In addition, the MIRVP addresses reference temperature shift concerns and pressurized thermal shock in accordance with Section 50.61. A description of the MIRVP is provided in BAW-1543A, Revision 2, [Reference 33] and in BAW 2251 [Reference 34]. The attributes of the MIRVP are provided in the following:

Purpose - The purpose of the MIRVP is to provide a method to monitor reactor pressure vessel materials containing Linde 80 high copper beltline welds for determining the reduction of material toughness by neutron irradiation embrittlement.

Scope - The scope of the MIRVP includes beltline plate and weld material for the beltline region of the Oconee reactor vessels.

Aging Effects - The applicable aging effect is the reduction of material toughness by neutron irradiation embrittlement.

Method - Fracture toughness specimens are irradiated within two operating B&W reactor vessels (i.e., Davis-Besse and Crystal River-3) and the participating Westinghouse reactor vessels. The specimens are irradiated in capsules that are located near the reactor vessel inside wall, thus enabling reactor vessel materials to become irradiated out to and beyond anticipated license renewal fluence levels. The fracture

toughness specimens are tested in accordance with applicable ASTM standards as identified in Section 5.0 of BAW-1543A, Revision 2 [Reference 33].

Industry Code or Standard - ASTM E 185 [Reference 35]; Regulatory Guide 1.99, Revision 2 [Reference 36]; ASTM standards as identified in Section 5.0 of BAW-1543A, Revision 2 [Reference 33], and BAW-1543, Revision 4, Supplement 2 [Reference 37];

Frequency - The capsule withdrawal schedules are presented in BAW-1543, Revision 4, Supplement 2 [Reference 37]. The MIRVP schedule may be altered due to unscheduled downtimes or extended outages at the host plants. In addition, certain surveillance capsules may receive additional irradiation to fully satisfy license renewal fluence requirements.

Acceptance Criteria or Standard - Fracture toughness specimens removed from the surveillance capsules will be laboratory tested to ensure reactor vessel fracture toughness properties exhibit upper shelf energy greater than 50 ft-lbs. If the Charpy upper-shelf energy drops below 50 ft-lbs, then it must be demonstrated that margins of safety against fracture are equivalent to those of Appendix G of ASME Section XI. The fracture toughness specimens removed from the surveillance capsules will also be evaluated to determine the adjusted reference temperature for the pressure- temperature limits (Section IV.A of Appendix G, 10 CFR Part 50) and RT_{PTS} value have been appropriately determined (10 CFR 50.61(c)(2)).

In addition, calculations of reference temperature for pressurized thermal shock (RT_{PTS}) must be below the screening criteria of 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds, respectively. If the projected reference temperature exceeds the screening criteria, licensees are required to submit an analysis and schedule for such flux reduction programs as are reasonably practicable to avoid exceeding the screening criteria. If no reasonably practicable flux reduction program will avoid exceeding the screening criteria, licensees shall submit a safety analysis to determine what actions are necessary to prevent potential failure of the reactor vessel if continued operation beyond the screening criteria is allowed.

Modifications to design and operation that result in changes to the neutron energy spectrum relative to that discussed in Chapter 4 of BAW-1543, Revision 4, must be compared to the energy spectrum in which the capsules were irradiated. If appropriate, the surveillance data obtained during the current term of operation must be adjusted to account for the revised neutron energy spectrum. The subsequent impact on the applicable embrittlement evaluations must be assessed.

Modifications to design and operation that result in changes to gamma heating relative to that discussed in BAW-1543, Revision 4, must be evaluated since gamma heating affects the 1/4T location. If the neutron spectrum changes and gamma heating changes, the surveillance data obtained during the current term of operation must be adjusted to account for the revised gamma heating. The subsequent impact on the applicable embrittlement evaluations must be assessed.

Modifications to design and operation that result in reactor vessel inlet temperature changes relative to those discussed in Chapters 3 and 4 of BAW-1543, Revision 4, must be assessed relative to the inlet temperature at which the applicable capsules were irradiated. If appropriate, the surveillance data obtained during the current term of operation must be adjusted to account for the revised vessel inlet temperatures. The subsequent impact on the applicable embrittlement evaluations must be assessed.

If modifications to design and operation result in changes to neutron energy spectrum, gamma heating, or the reactor inlet temperature relative to that discussed in BAW-1543, Revision 4, then NRC will be notified and a program to determine impact will be proposed. [References 38 and 39]

9 **Corrective Action** - Not applicable because this program is collecting irradiated materials data.

9 **Regulatory Basis** - Section 50.60, Acceptance criteria for fracture prevention measures for lightwater
9 nuclear power reactors for normal operation; Section 50.61, Fracture Toughness requirements for
9 protection against pressurized thermal shock; Appendix G to Part 50, Fracture Toughness Requirements;
9 Appendix H to Part 50, Reactor Vessel Material Surveillance Program Requirements; and Oconee
9 Improved Technical Specification 3.4.3, Reactor Coolant System Pressure and Temperature (P/T) Limits.

9 18.3.19.2 Cavity Dosimetry Program

9 The Cavity Dosimetry Program is an Oconee on-site method to continuously monitor the reactor vessel
9 beltline region fluence for determining the reduction of material toughness due to neutron irradiation
9 embrittlement.

9 **Purpose** - The purpose of the Cavity Dosimetry Program is to provide an improved methodology to more
9 accurately estimate reactor vessel accumulated neutron fluence for the reactor vessel limiting beltline
9 welds. Cavity dosimetry measurements are used to verify the accuracy of fluence calculations and to
9 determine fluence uncertainty values.

9 **Scope** - All three Oconee reactor vessels are included in the cavity dosimetry program; however, only the
9 Oconee Unit 2 reactor vessel has installed cavity dosimetry. The Oconee Unit 1 and Oconee Unit 3
9 reactor vessel fluence uncertainty values are based on Oconee Unit 2 cavity dosimetry results due to
9 similar design, fabrication, operation, and fuel loading patterns.

9 **Aging Effects** - The reduction of material toughness by irradiation embrittlement.

9 **Method** - Dosimeters (i.e., U_{238}, Np_{237}, Ni, Cu, etc.) are irradiated in the cavity region outside of the
9 Oconee Unit 2 reactor vessel. Cavity dosimetry was irradiated at Oconee Unit 2 for cycle 9, cycle 10,
9 combined cycles 11-12, combined cycles 13-14, and combined cycles 15-16. At present, cavity dosimetry
9 is being irradiated at Oconee Unit 2 for combined cycles 17-18.

9 The cavity dosimeters are measured to determine the activity resulting from the fast fluence irradiation. In
9 addition, calculations of the dosimetry activities are performed using operational data. The calculations
9 are compared to the measurements to verify the accuracy and the uncertainty in the calculated fluence.

9 **Industry Code or Standard** - Regulatory Guide 1.99, Revision 2 [Reference 36]; ASTM E 185 [Reference
9 35]; Draft Regulatory Guide - 1053 [Reference 40]; BAW-2241P [Reference 41].

9 **Frequency** - At present, cavity dosimetry is changed out on an every-other-cycle basis. Future trends
9 indicate extending the frequency to an every-third-cycle exchange period or longer. The cavity dosimetry
9 exchange schedule may be altered due to changes in fuel type, fuel loading pattern, or power rating of
9 Oconee Unit 2.

9 **Acceptance Criteria or Standard** - Dosimetry removed from the cavity dosimetry holder is laboratory
9 tested to count the amount of neutron irradiation damage to the dosimetry specimens. Computer
9 analyses are used to calculate the dosimeter activities and associated fluence. Following computer
9 analyses, the calculated accumulated fast fluence will be determined. The results of the fluence uncertainty
9 values should be within the NRC-suggested limit of $\pm 20\%$. Specific corrective actions will be
9 implemented in accordance with the Duke Quality Assurance Program.

9 **Corrective Action** - As additional cavity dosimetry is withdrawn and tested, cavity dosimetry exchange
9 frequency may be adjusted, as appropriate. If the comparison of calculations to measurements of the

Unit 2 multiple dosimeters fail to meet +20%, measurements and calculations will be reviewed to locate the discrepancy.

Regulatory Basis - Section 50.60, Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation; Appendix H to Part 50, Reactor Vessel Material Surveillance Program Requirements; and Oconee Improved Technical Specification 3.4.3, Reactor Coolant System Pressure and Temperature (P/T) Limits.

18.3.19.3 Fluence and Uncertainty Calculations

The reactor vessel Fluence and Uncertainty Calculations are used as inputs to the pressure temperature limit curves and pressurized thermal shock calculations. Updating fluence and uncertainty calculations is essential to maintaining an accurate prediction of the actual reactor vessel accumulated neutron fast fluence value.

Purpose - The purpose of the reactor vessel Fluence and Uncertainty Calculations is to provide an accurate prediction of the actual reactor vessel accumulated neutron fast fluence value.

Scope - The Fluence And Uncertainty Calculations includes all three of the Oconee reactor vessels.

Aging Effect - The reduction of material toughness by neutron irradiation embrittlement.

Method - The cavity dosimetry program yields irradiated dosimeters that are analyzed based on Oconee specific geometry models (i.e., Mark-B8 fuel, reactor vessel, capsule holder, concrete structures), macroscopic cross sections, cycle-specific sources using the DORT and GIP computer codes, and a reference set of microscopic cross sections (BUGLE-93). Specific attention is made to target fluence values for limiting reactor vessel beltline circumferential weld locations.

Industry Code or Standard - Regulatory Guide 1.99, Revision 2 [Reference 36]; ASTM E 185 [Reference 35]; Draft RG-1053 [Reference 40], BAW-2241P [Reference 41].

Frequency - Fluence and uncertainty calculations are expected to follow each cavity dosimetry analysis for the next few years. The frequency of updating fluence and uncertainty calculations may change as additional data are obtained. Future decisions concerning the frequency of withdrawal of dosimetry will be based on changes in fuel type or fuel loading pattern.

Acceptance Criteria or Standard - The results of the fluence uncertainty values are to be within the NRC-suggested limit of ±20%. Calculated fluence values for fluence levels above 1.0MeV are compared with measurement values to determine if calculations contain any errors. This methodology represents a continuous validation process to ensure that no biases have been introduced, and that the uncertainties remain comparable to the reference benchmarks.

Corrective Action - As additional cavity dosimetry is withdrawn and tested, fluence and uncertainty calculations will be revised and updated accordingly. If comparisons of dosimetry calculations to measurements are not within acceptance standards, then the calculations will be revised. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Appendix H to Part 50, Reactor Vessel Material Surveillance Program Requirements; and Oconee Improved Technical Specification 3.4.3, Reactor Coolant System Pressure and Temperature (P/T) Limits.

18.3.19.4 Pressure Temperature Limit Curves

Pressure Temperature Limit Curves determine the operating region during normal heatup, normal cooldown, and inservice leak and hydrostatic test transients. Periodically they are updated based on revised accumulated fluence values, additional effective full power years, and to incorporate methodology or regulatory changes.

Purpose - The purpose of the Pressure Temperature Limit Curves is to establish the normal operating limits for the Reactor Coolant System.

Scope - The scope of the Pressure Temperature Limit Curves includes all three of the Oconee reactor vessels.

Aging Effects - The reduction of material toughness by neutron irradiation embrittlement.

Method - Pressure temperature limit curves will be generated in accordance with the requirements of Appendix G of 10 CFR Part 50. Pressure temperature curves are generated assuming a postulated 1/4T surface flaw in accordance with ASME Section XI, Appendix G [Reference 42]. Bounding input heatup and cooldown transients are used to develop the pressure temperature curves.

Industry Code or Standard - ASME Section XI, Appendix G, 1989 Edition [Reference 42]; ASME Code Case N-514 [Reference 43]; Regulatory Guide 1.99, Revision 2 [Reference 36], 10 CFR 50, Appendix G.

Frequency - Pressure Temperature Limit Curves are valid for a period of time expressed in Effective Full Power Years (EFPY). The curves are updated prior to exceeding this time period.

Acceptance Criteria or Standard - NRC approved Pressure Temperature Limit Curves must be in place for continued plant operation.

Corrective Action - Oconee Improved Technical Specifications, ITS 3.4.3, RCS Pressure and Temperature (P/T) Limits, require valid pressure-temperature limits prior to and during plant operations. Actions to be taken if the pressure- temperature limits are exceeded are specified in Oconee Improved Technical Specifications 3.4.3. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Oconee Improved Technical Specification ITS 3.4.3, Reactor Coolant System Pressure and Temperature (P/T) Limits.

18.3.19.5 Effective Full Power Years

Effective Full Power Years provide a measurement of the irradiation of the reactor vessel and is required input for determining pressure - temperature limit curves and pressurized thermal shock guidelines. The values for Effective Full Power Years are established from the calculation of Effective Full Power Hours and Effective Full Power Days.

Purpose - The purpose Effective Full Power Years is to accurately monitor and tabulate the accumulated irradiation of the reactor vessel.

Scope - The scope of the Effective Full Power Years activity includes all three of the Oconee reactor vessels.

Aging Effect - The reduction of material toughness by neutron irradiation embrittlement.

9 **Method** - The effective full power days of plant operation are based on reactor vessel incore power
9 readings. The Nuclear Applications Software, which runs on the operator aid computer, collects incore
9 instrument data. Site reactor engineers determine effective full power days values by comparing the
9 burnup to the thermal power calculated burnup. All data is collected continuously for all three Oconee
9 units.

9 **Industry Code or Standard** - No code or standard exists to guide or govern this activity.

9 **Frequency** - Each unit is continuously monitored by computer and updated weekly by site reactor
9 engineers to determine the effective full power days of Reactor Coolant System operation during the
9 previous seven day period.

9 **Acceptance Criteria or Standard** - For a given fuel cycle, the updated effective full power days calculation
9 based on the power history must be within ± 0.25 EFPD of the operator aid computer generated value.

9 **Corrective Action** - As additional effective full power hour and effective full power day values become
9 available, effective full power year calculations are revised and updated accordingly. Specific corrective
9 actions will be implemented in accordance with the Duke Quality Assurance Program.

9 **Regulatory Basis** - Oconee Improved Technical Specification 3.4.3, Reactor Coolant System Pressure and
9 Temperature (P/T) Limits.

9 18.3.20 REACTOR VESSEL INTERNALS INSPECTION

9 **Purpose** - The purpose of the Reactor Vessel Internals Inspection is to inspect and examine the condition
9 of reactor vessel internals items in order to assure that the applicable aging effects will not result in loss of
9 the intended functions of the reactor vessel internals during the period of extended operation.

9 **Scope** - The scope of this inspection consists of the reactor vessel internals stainless steel items for Oconee
9 Units 1, 2 and 3. For inspection purposes, these items can be separated into four groups - (1) items
9 comprised of plates, forgings, and welds, (2) baffle bolts, (3) core barrel bolts and thermal shield bolts, and
9 (4) items fabricated from cast austenitic stainless steel (CASS) and martensitic steel. More specifically, the
9 items fabricated from CASS and martensitic steel include control rod guide tube spacers, vent valve
9 bodies, Unit 3 outlet nozzles, and incore guide tube assembly spiders. The vent valve retaining rings,
9 fabricated from martensitic stainless steel, are also included in this inspection.

9 **Aging Effects** - The applicable aging effects for items comprised of plates, forgings, and welds are cracking
9 due to irradiation assisted stress corrosion, stress corrosion, reduction of fracture toughness due irradiation
9 embrittlement, and dimensional changes due to void swelling.

9 The applicable aging effects for baffle bolts are cracking due to irradiation assisted stress corrosion,
9 reduction of fracture toughness due to irradiation embrittlement, and dimensional changes due to void
9 swelling.

9 The applicable aging effects for items comprised of core barrel bolts, and thermal shield bolts are cracking
9 due to irradiation assisted stress corrosion, stress corrosion, reduction of fracture toughness due irradiation
9 embrittlement, and loss of bolted closure integrity due to stress relaxation.

9 The applicable aging effects for item fabricated from CASS and martensitic steel are reduction of fracture
9 toughness by thermal embrittlement and irradiation embrittlement.

9 **Method** - Current plans are to perform a visual inspection of the items comprised of plates, forgings, and
9 welds. Activities are in progress to develop and qualify the inspection method.

9 Current plans are to perform a volumetric inspection of the baffle bolts. Activities are in progress to
9 develop and qualify the inspection method.

9 Current plans are to perform a visual inspection of core barrel bolts and thermal shield bolts. Activities
9 are in progress to determine if volumetric examinations will be required.

9 For items fabricated from CASS and martensitic steel, an analytical approach to assess the effect of
9 reduction of fracture toughness on the applicable reactor vessel internals items will be performed. The
9 specific inspection method will depend on the results of these analyses. The Oconee Unit 3 outlet nozzles
9 will be inspected if the results of the analysis indicate such inspection is necessary.

9 Should data or evaluations indicate that the above inspections can be modified or eliminated, Duke will
9 provide plant-specific justification to demonstrate the basis for the modification or elimination.

9 **Sample Size** - The sample size for the inspection of each Oconee unit will be determined as part of the
9 development of the inspection method.

9 **Industry Codes or Standards** - No code or standard currently exists to guide or govern this inspection.

9 **Frequency** - The Reactor Vessel Internals Inspection will be performed once on each set of reactor vessel
9 internals during the twenty-year period of extended operation. Preparation for these inspections will
9 include unit selection and proper sequencing of the inspections as well as the opportunity to develop a
9 lead unit for these inspections.

9 **Acceptance Criteria or Standard** - For the items comprised of plates, forgings, and welds that will be
9 visually inspected, critical crack size will be determined by analysis. Acceptance criteria for all aging
9 effects will be developed prior to the inspection.

9 For baffle bolts, any detectable crack indication is unacceptable for a particular baffle bolt. The number
9 of baffle bolts needed to be intact and their locations will be determined by analysis. Acceptance criteria
9 for dimensional changes due to void swelling will be developed prior to the inspection.

9 For core barrel bolts, and thermal shield bolts any detectable crack is unacceptable. Acceptance criteria for
9 all aging effects will be developed prior to the inspection.

9 For items fabricated from CASS and martensitic steel, critical crack size will be determined by analysis.
9 Acceptance criteria for all aging effects will be developed prior to the inspection.

9 **Corrective Action** - If the results of the inspection are not acceptable, then actions will be taken to repair
9 or replace the affected items or to determine by analysis the acceptability of the items. Specific corrective
9 actions will be implemented in accordance with the Duke Quality Assurance Program.

9 **Timing of New Program or Activity** - The inspections among the three sets of reactor vessel internals will
9 be spaced out over the twenty-year period of extended operation. The first inspection will occur early in
9 the period. The second will occur near the middle of the period, and the third will occur in the latter
9 third of the twenty-year period. (The third inspection will be scheduled prior to the last year of the
9 twenty-year period of extended operation for the unit inspected.)

Regulatory Basis - Renewal Applicant Action Item 4.1 (Items 5, 6, 7, 8, and 9) in the Safety Evaluation Report for BAW-2248A. Duke letter dated December 17, 1999 [Reference 44], and Final SER [Reference 2].

18.3.21 SERVICE WATER PIPING CORROSION PROGRAM

Purpose - The Service Water Piping Corrosion Program will manage loss of material due to general and localized corrosion for components in the following systems:

- Auxiliary Service Water System,
- Chilled Water System (raw water portion of the coolers)
- Component Cooling System (raw water side of the component coolers)
- Condenser Circulating Water System,
- Diesel Jacket Water Cooling System (raw water side of the heat exchangers)
- Essential Siphon Vacuum System
- High Pressure Service Water System,
- Keowee Service Water System,
- Keowee Turbine Generator Cooling Water System, and
- Keowee Turbine Sump Pump System.
- Low Pressure Injection System (for the raw water side of the Decay Heat Cooler),
- Low Pressure Service Water System,
- Siphon Seal Water System
- SSF Auxiliary Service Water System,

Scope - The scope of the program credited for license renewal includes all bronze, carbon steel, cast iron and stainless steel components in the license renewal portions of the systems listed in the Purpose. The program includes the inspection of carbon steel piping components exposed to raw water which are more susceptible to general corrosion and which serve as a leading indicator of the general material condition of the system components. In addition, brass piping components located at Keowee are inspected.

Over 30 different carbon steel piping component inspection locations have been established throughout the applicable systems based on the understanding that fluid flow rates are a prime contributor to the conditions conducive to corrosion. Inspection locations are spread among the four flow regimes: (1) stagnant, (2) intermittent, (3) low flow or approximately three feet per second or less, and (4) normal flow or flow greater than three feet per second based on system operations.

Aging Effects - The aging effects of concern are loss of material due to general corrosion of brass, carbon steel, and cast iron components and loss of material due to localized corrosion for brass, carbon steel, cast iron and stainless steel that may reveal itself in the raw water systems within the scope of license renewal.

Method - Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing. Also, visual examination is used as a general characterization tool in conjunction with ultrasonic testing when access to interior surfaces is allowed such as during plant modifications.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability is judged in accordance with the component design code of record.

Frequency - Because the corrosion phenomena is slow-acting, inspection frequency varies for each location with a periodicity on the order of five to ten years. The frequency of re-inspection depends on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events and plant operating experiences.

Acceptance Criteria - No inspection locations falling below the minimum pipe wall thickness values for the inspection locations as defined in the program. These minimum values have been determined based on design pressure or structural loading using the piping design code of record and then applying additional conservatism.

Corrective Action - Inspection locations that fall below the acceptance criteria are repaired or replaced prior to the system returning to service unless an engineering analysis allows further operation. In the cases where a component may be allowed to continue in service, a re-inspection interval is established in the program.

Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Service Water Piping Corrosion Program.

Regulatory Basis - The Service Water Piping Corrosion Program is a formalization of a portion of the commitments made in response to GL 89-13, primarily those associated with component pressure boundary maintenance [References 24, 25, 26, 27, and 28]; Application [Reference 1] and Final SER [Reference 2].

18.3.22 SYSTEM PERFORMANCE TESTING ACTIVITIES

The following raw water systems have been identified as containing smaller diameter piping that could be affected by fouling and will be managed by System Performance Testing Activities:

- Auxiliary Service Water System,
- Keowee Turbine Generator Cooling Water System,
- Keowee Turbine Sump Pump System,
- Low Pressure Service Water System,
- Siphon Seal Water System, and
- SSF Auxiliary Service Water System.

Performance testing for these systems will provide assurance that the components are capable of delivering adequate flow at a sufficient pressure as required to meet system and accident load demands.

Periodic operation, testing and inspections are completed for the above systems at a range of frequencies. The Turbine Generator Cooling Water System is operated at design conditions every time the Keowee units operate. The Keowee units operate at about a ten percent capacity factor. Periodic testing frequencies range from quarterly to every third refueling outage, depending on the system. Visual inspections of the Auxiliary Service Water System are conducted every five years.

Flow capacity is determined and compared to test acceptance criteria established by engineering and to previous test results. The results of visual inspections are evaluated by engineering. If the results of the flow tests and inspections do not meet acceptance criteria, then corrective actions, which could require piping replacement, are undertaken. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the System Performance Testing Activities.

The activities credited here for license renewal are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 24, 25, 26, 27 and 28].

The continued implementation of the System Performance Testing Activities provides reasonable assurance that the aging effects will be managed such that mechanical components will continue to

perform their intended functions consistent with the current licensing basis for the period of extended operation.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.23 TENDON - SECONDARY SHIELD WALL - SURVEILLANCE PROGRAM

Purpose - The purpose of the Tendon - Secondary Shield Wall - Surveillance Program is to inspect the Secondary Shield Wall Post-Tension Tendon System to ensure that the quality and structural performance of the secondary shield wall is consistent with the licensing basis.

Scope - The scope of this program includes the tendon wires and tendon anchorage hardware, including bearing plates, anchorheads, bushing, buttonheads, and shims of the Units 1, 2, and 3 Secondary Shield Wall Tendons.

Aging Effects - The applicable aging effects include loss of material due to corrosion and cracking of tendon anchorage; wire force relaxation; loss of material due to corrosion and breakage of wires; loss of material due to corrosion and cracking of bearing plate; cracked, split, and broken buttonheads; cracking and loss of material due to corrosion of shims.

Method - Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons.

Industry Code or Standard - No code or standard exists to guide or govern this program.

Frequency - Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons every other refueling outage.

Acceptance Criteria or Standard - No unacceptable visual indication of moisture, discoloration, foreign matter, rust, corrosion, splits or cracks in the buttonheads, broken or missing wires, and other obvious damage as identified by the accountable engineer. Lift-off forces are measured and compared to established acceptance criteria. The minimum required forces for the tendon groups range from 390 kips to 560 kips depending on the location of the group.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by replacement. Specific corrective actions are implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.24 230 KV KEOWEE TRANSMISSION LINE INSPECTION

Purpose - The purpose of the 230 kV Keowee Transmission Line Inspection is to maintain the structural integrity of the 230 kV Keowee transmission line structures.

Scope - The 230 kV Keowee Transmission Line Inspection includes steel towers, concrete foundations, and hardware within the 230 kV Keowee transmission line.

Aging Effects - The applicable aging effects of concern include loss of material due to corrosion of the steel structures and loss of material due to spalling or scaling for concrete components.

Method - The inspection requires a visual examination of the towers.

9 **Industry Code or Standard** - National Electric Safety Code, Part 2, Safety Rules for Overhead Lines; Rule
9 214 Inspection and Tests of Lines and Equipment.

9 **Frequency** - The inspections are performed once every five years.

9 **Acceptance Criteria or Standard** - No unacceptable visual indication of aging effects as evaluated by the
9 inspector.

9 **Corrective Action** - Areas that do not meet the acceptance criteria are evaluated for continued service or
9 corrected by repair or replacement. Specific corrective actions are implemented in accordance with the
9 Problem Investigation Process. The Problem Investigation Process applies to all structures and
9 components within the scope of the 230 kV Keowee Transmission Line Inspection.

9 **Regulatory Basis** - National Electric Safety Code, Part 2, Safety Rules for Overhead Lines, Rule 214
9 Inspection and Tests of Lines and Equipment, Application [Reference 1] and Final SER [Reference 2].

18.4 ADDITIONAL COMMITMENTS

The following are additional commitments that are not identified in the preceding sections of Chapter 18, "Aging Management Programs and Activities."

1. A plant-specific analysis will be performed to demonstrate that, under loss-of-coolant-accident (LOCA) and seismic loading, the internals have adequate ductility to absorb local strain at the regions of maximum stress intensity and that irradiation accumulated at the expiration of the renewal license will not adversely affect deformation limits. Data will be developed to demonstrate that the internals will meet the deformation limits at the expiration of the renewal license. (Reference: Duke letter to the NRC dated December 17, 1999, Attachment 1, page 8)

2. The Steam Generator Tube Surveillance Program complies with the guidance provided in NEI 97-06, "Steam Generator Program Guidelines" for inspection scope, personnel qualification, and technique qualification. Condition monitoring and operational assessments are performed using the NEI 97-06 guidelines. (Reference: Duke letter to NRC dated February 17, 1999, Attachment 1, page 63)

3. Table 5-24, Table 5-25, Table 5-26, Table 5-27, Table 5-28, and Table 5-29 of the UFSAR contain reactor vessel materials data. These tables will be revised to include the current data from BAW-2325 (Revision 1 or the most current revision available) by December 31, 2000. (Reference: Duke letter to NRC dated March 27, 2000, Submittal of UFSAR Supplement, March 2000)

4. The Oconee Thermal Fatigue Management Program will be modified to incorporate a plant-specific resolution of Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life." Plant-specific actions will be taken either in the manner that was described in Duke letter to the NRC dated October 15, 1999, "Safety Evaluation Report - Oconee Nuclear Station License Renewal Application, Comments and Responses to Open Items and Confirmatory Items, Response to Open Item 4.2.3-2," or by using another approach that is acceptable to the NRC staff. (Reference: Duke letter to NRC dated October 15, 1999, Attachment 2, page 111)

18.5 REFERENCES

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1988 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.
2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,* Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.
3. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
4. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
5. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.3-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
6. M. S. Tuckman (Duke) letter dated May 10, 1999 to Document Control Desk (NRC), Attachment 1, Response to Items 4.3.9-6, - 7, and -8, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
7. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
8. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999 to Document Control Desk (NRC), Attachment 1, Pages 43-48, Response to Requests for Additional Information, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
9. W. T. Russell (NRC) letter dated November 19, 1993 to W. H. Rasin (NUMARC, now NEI).
10. M. S. Tuckman (Duke) letter dated July 30, 1997 to Document Control Desk (NRC), Oconee Nuclear Station - Response to Generic Letter 97-01: *Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,* Docket Nos. 50-269, -270, and -287.
11. ANSI B30.2.0, "Overhead and Gantry Cranes", American National Standard, Section 2-2, *Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks and Slings,* The American Society of Mechanical Engineers, New York.
12. ANSI B30.16, "Overhead Hoists (Underhung)", The American Society of Mechanical Engineers, New York.
13. 29 CFR Chapter XVII, 1910.179, *Occupational Safety and Health Administration, Overhead and Gantry Cranes.*
14. W. R. McCollum, Jr. (Duke) letter dated February 8, 1999 to Document Control Desk (NRC), Response to Requests for Additional Information (RAI), Attachment 1, Response to RAI 4.12-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
15. 18 CFR Part 12 - *Safety of Water Power Projects and Project Works,* 59 FR 54815, Nov. 2, 1994.
16. IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants.*
17. H. B. Tucker (Duke) letter dated September 14, 1987 to Document Control Desk (NRC), Response to IE Bulletin 87-01, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

18. Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning.*

19. H. B. Tucker (Duke) letter dated July 21, 1989, Response to Generic Letter 89 08, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

20. Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,* dated March 17, 1988.

21. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999 to Document Control Desk (NRC), Response to Requests for Additional Information Attachment 7, Commitment #1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

22. H. B. Tucker (Duke) letter dated August 1, 1988 to Document Control Desk (NRC), *Response to Generic Letter 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,* Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

23. M. S. Tuckman (Duke) letter dated December 17, 1999, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Response to SER Open Item 3.9.3-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

24. H. B. Tucker (Duke) letter dated January 26, 1990 to the Document Control Desk (NRC), *Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

25. H. B. Tucker (Duke) letter dated May 31, 1990 to the Document Control Desk (NRC), *Supplemental Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

26. J. W. Hampton (Duke) letter dated December 10, 1992 to the Document Control Desk (NRC), *Confirmation of Implementation of Recommended Action Related to Generic Letter 89-13,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, - 270, and -287.

27. J. W. Hampton (Duke) letter dated September 1, 1994 to the Document Control Desk (NRC), *Follow Up to a Deviation Notice in NRC Inspection Report 93-25 to Revise Response to 89-13,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and - 287.

28. J. W. Hampton (Duke) letter dated April 4, 1995 to Document Control Desk (NRC), *Supplemental Response #3 to Generic Letter 89-13,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

29. M. S. Tuckman (Duke) letter dated January 12, 2000, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Revised Response to SER Open Item 3.9.3-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

30. Generic Letter 85-20, *Resolution of Generic Issue 69: High Pressure Injection/Make-up Nozzle Cracking in Babcock and Wilcox Plants.*

31. IE Bulletin 88-08, *Thermal Stresses in Piping Connected to the Reactor Coolant System.*

32. D. B. Matthews (NRC) letter dated July 11, 1997 to J. H. Taylor (FTI), Babcock & Wilcox Owners Group (B&WOG) Reactor Vessel Working Group Report BAW-1543, Revision 4, Supplement 2, *Supplement to the Master Integrated Reactor Vessel Surveillance Program,* TAC No. M98089.

33. BAW-1543A, Revision 2, *Integrated Reactor Vessel Surveillance Program,* B&W Owners Group Materials Committee, May 1985.

34. BAW-2251, *Demonstration of the Management of Aging Effects for the Reactor Vessel,* The B&W Owners Group Generic License Renewal Program, June 1996.

35. ASTM E 185, *Standard Practice for Conducting Surveillance Test for Light-Water Cooled Nuclear Power Reactor Vessels.*

9 36. Regulatory Guide 1.99, Revision 2, NRC, *Radiation Embrittlement of Reactor Vessel Material,* May
9 1998.

9 37. BAW-1543, Revision 4, Supplement 2, *Supplement to the Master Integrated Reactor Vessel*
9 *Surveillance Program,* Babcock & Wilcox Owners Group (B&WOG) Reactor Vessel Working Group.

9 38. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999, Response to Request For Additional
9 Information, Attachment 1, Response to RAI 3.4.5-2 pages 24 and 25, Oconee Nuclear Station, Units
9 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

9 39. M. S. Tuckman (Duke) letter dated May 10, 1999, to Document Control Desk (NRC), Response to
9 Requests for Additional Information, Attachment 1, Response to Potential Open Item 3.4.5-9,
9 Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

9 40. Draft Regulatory Guide - 1053, *Calculational and Dosimetry Method for Determining Pressure Vessel*
9 *Neutron Fluence,* June 1996.

9 41. BAW-2241P, *Fluence and Uncertainty Methodologies,* April 1997 (under NRC review as of June
9 1998).

9 42. ASME Section XI, Appendix G for Nuclear Power Plants, Division 1, *Protection Against Non-Ductile*
9 *Failure.*

9 43. ASME Code Case N-514, *Low Temperature Overpressure Protection,* Section XI, Division 1.

9 44. M. S. Tuckman (Duke) letter dated December 17, 1999, to Document Control Desk (NRC),
9 Response to NRC letter dated November 18, 1999, Response to SER Open Items 3.4.3.3-3, 3.4.3.3-4,
9 and 3.4.3.3-5, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

9 THIS IS THE LAST PAGE OF THE CHAPTER 18 TEXT PORTION.

APPENDIX 18. CHAPTER 18 TABLES AND FIGURES

9 **Table 18-1 (Page 1 of 3). Summary Listing of the Programs, Activities and TLAA**

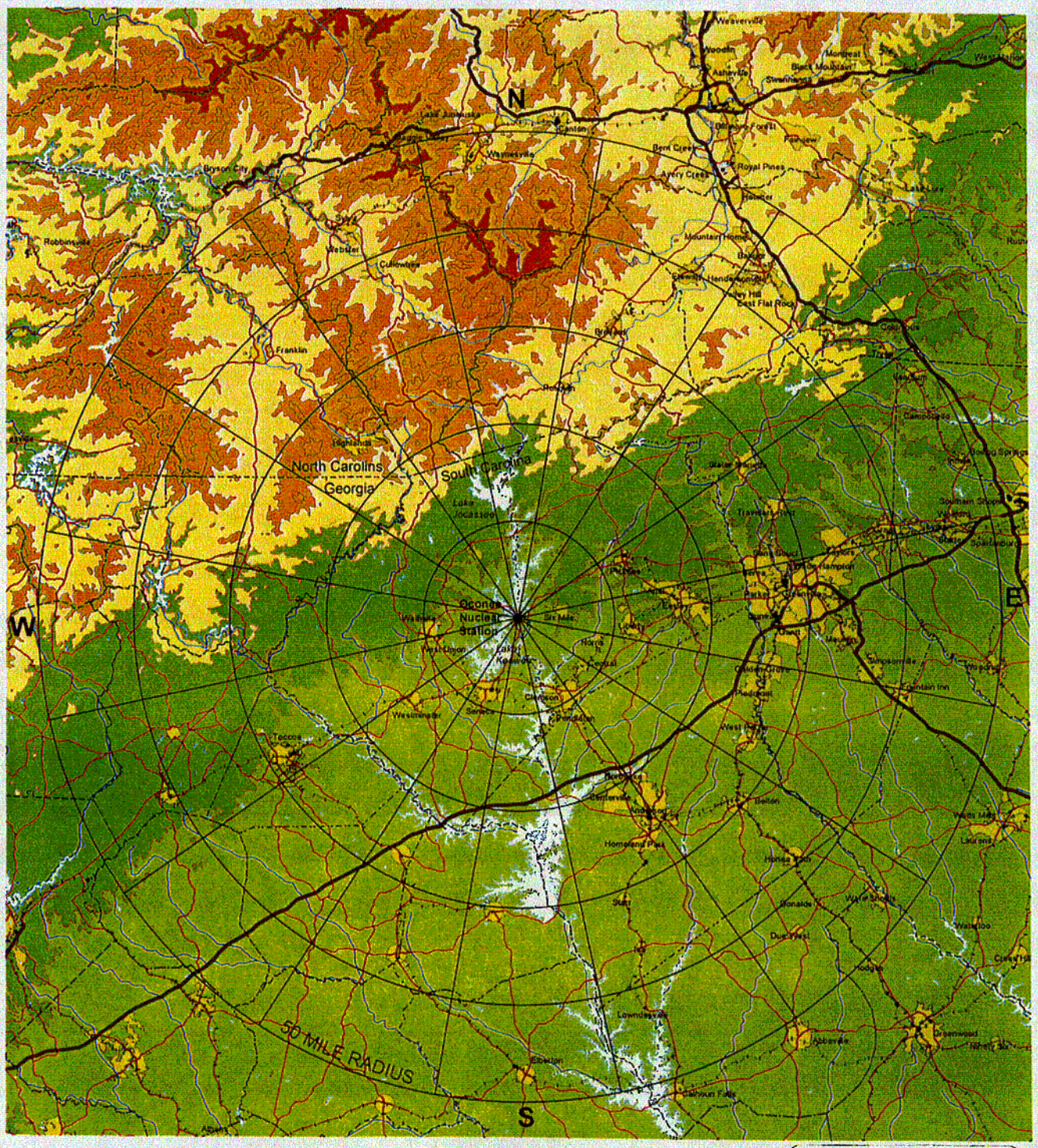
Topic	Program/Activity or TLAA	UFSAR/ITS Location
Alloy 600 Aging Management Program	Program/Activity	18.3.1
Battery Rack Inspections	Program/Activity	ITS: SR 3.8.1.11, SR3.8.3.3, SR 3.10.1.10
Cast Iron Selective Leaching Inspection	Program/Activity	18.2.1
Chemistry Control Program	Program/Activity	18.3.2 ITS: 5.5.14
Containment Inservice Inspection Plan	Program/Activity	18.3.3
Containment Leak Rate Testing Program	Program/Activity	ITS 5.5.2
Containment Liner Plate and Penetrations - Thermal Cycles	TLAA	3.8.1.5.3
Containment Post-Tensioning System - Prestress Loss	TLAA	3.8.1.5.2, 16.6.2 18.3.3
Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program	Program/Activity	18.3.4
Crane Inspection Program	Program/Activity	18.3.5
Cranes and Control of Heavy Loads	TLAA	3.12
Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances	Program/Activity	18.3.6
Elevated Water Storage Tank Inspection	Program/Activity	18.3.7
Environmental Qualification of Electrical Equipment	TLAA	3.11
Federal Energy Regulatory Commission (FERC) Five Year Inspections	Program/Activity	18.3.8
Fire Protection Program	Program/Activity	16.9.1, 16.9.2, 16.9.4, 16.9.5, 18.3.17.8
Flow Accelerated Corrosion Program	Program/Activity	18.3.9
Fluid Leak Management Program	Program/Activity	18.3.10
Galvanic Susceptibility Inspection	Program/Activity	18.2.2

9 **Table 18-1 (Page 2 of 3). Summary Listing of the Programs, Activities and TLAA**

9 9 Topic	Program/Activity or TLAA	UFSAR/ITS Location
9 Heat Exchanger Performance Testing Activities	Program/Activity	18.3.11
9 Inservice Inspection Plan	Program/Activity	18.3.12
9 9 Inspection Program for Civil Engineering Structures and Components	Program/Activity	18.3.13
9 9 Insulated Cables and Connections Aging Management Program	Program/Activity	18.3.14
9 Keowee Air and Gas Systems Inspection	Program/Activity	18.2.3
9 Keowee Oil Sampling Program	Program/Activity	18.3.15
9 Non-Class 1 Piping - Thermal Cycles	TLAA	3.2.2.2
9 9 Once Through Steam Generator Upper Lateral Support Inspection	Program/Activity	18.2.4
9 Penstock Inspection	Program/Activity	18.3.16
9 Pressurizer Examinations	Program/Activity	18.2.5
9 Preventive Maintenance Activities	Program/Activity	18.3.17
9 9 Program to Inspect High Pressure Injection Connections to the Reactor Coolant System	Program/Activity	18.3.18
9 Reactor Building Spray System Inspection	Program/Activity	18.2.6
9 9 Reactor Coolant Pump Flywheel	TLAA	ITS 5.5.8 5.4.4.2
9 9 Reactor Coolant Pump Motor Oil Collection System Inspection	Program/Activity	18.2.7
9 9 9 Reactor Coolant System and Class 1 Components (include leak-before-break) (Oconee Thermal Fatigue Management Program)	TLAA	5.2.1.4 5.2.x 18.4
9 9 Reactor Coolant System Operational Leakage Monitoring	Program/Activity	ITS 3.4.13 ITS 3.4.15
9 9 9 Reactor Vessel	TLAA	5.2.3.3.6, 5.2.3.3.x, y 18.4
9 Reactor Vessel Integrity Program	Program/Activity	18.3.19
9 9 Reactor Vessel Internals	TLAA	4.5.1.2 18.4
9 Reactor Vessel Internals Inspection	Program/Activity	18.3.20
9 Service Water Piping Corrosion Program	Program/Activity	18.3.21
9 Small Bore Piping Inspection	Program/Activity	18.2.8
9 Spent Fuel Rack Boraflex	TLAA	9.1.2.5

9 **Table 18-1 (Page 3 of 3). Summary Listing of the Programs, Activities and TLAA**

Topic	Program/Activity or TLAA	UFSAR/ITS Location
Steam Generator Tube Surveillance Program	Program/Activity	ITS 5.5.10 18.4
System Performance Testing Activities	Program/Activity	18.3.22
Tendon - Secondary Shield Wall - Surveillance Program	Program/Activity	18.3.23
Treated Water Systems Stainless Steel Inspection	Program/Activity	18.2.9
230 kV Keowee Transmission Line Inspections	Program/Activity	18.3.24



GENERAL AREA MAP
OCONEE NUCLEAR STATION
DUKE POWER COMPANY
FIGURE 2-3

Ground Elevations in Feet

- Sea Level - 999
- 1000 - 1999
- 2000 - 2999
- 3000 - 4999
- 5000 - 7000

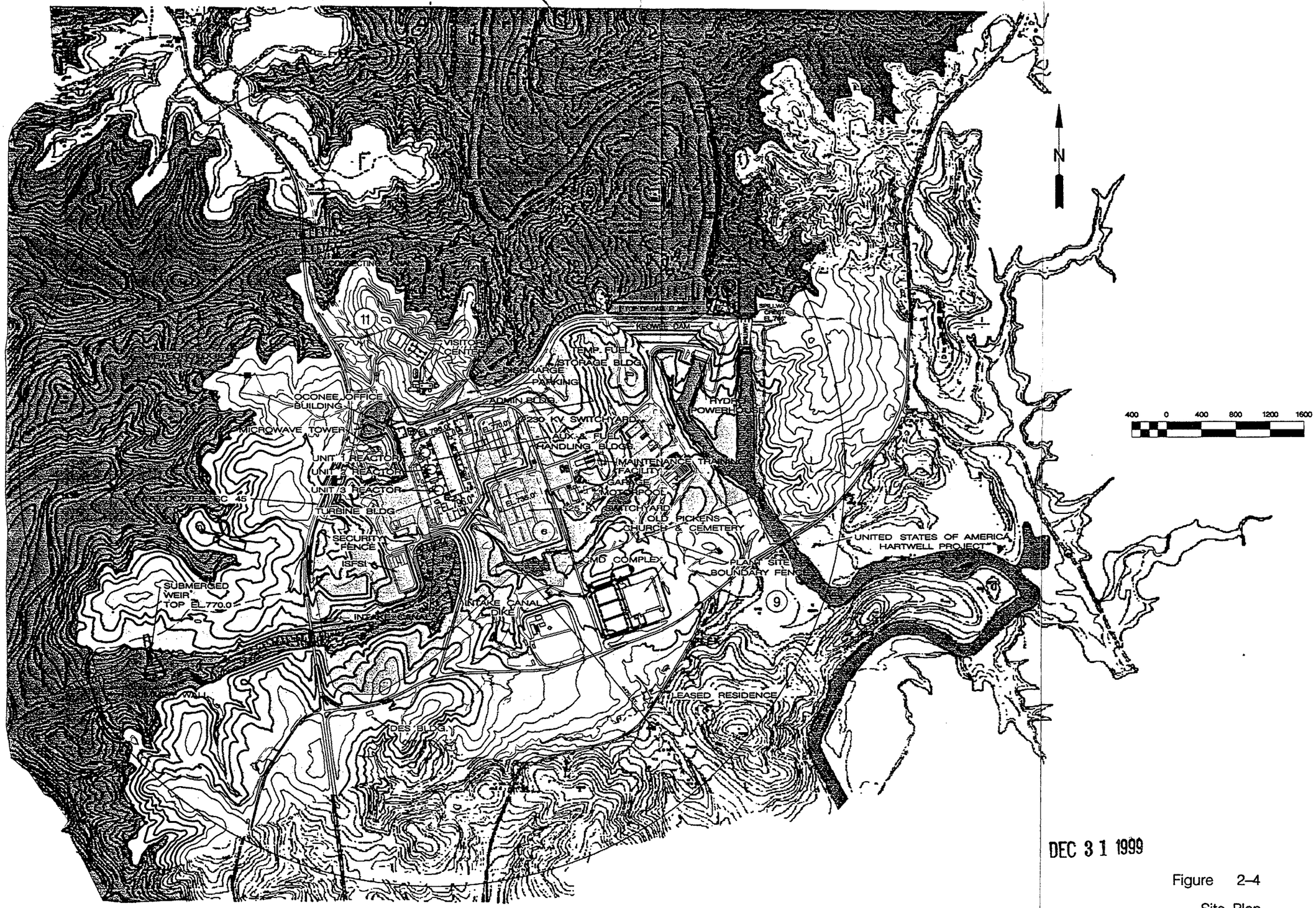


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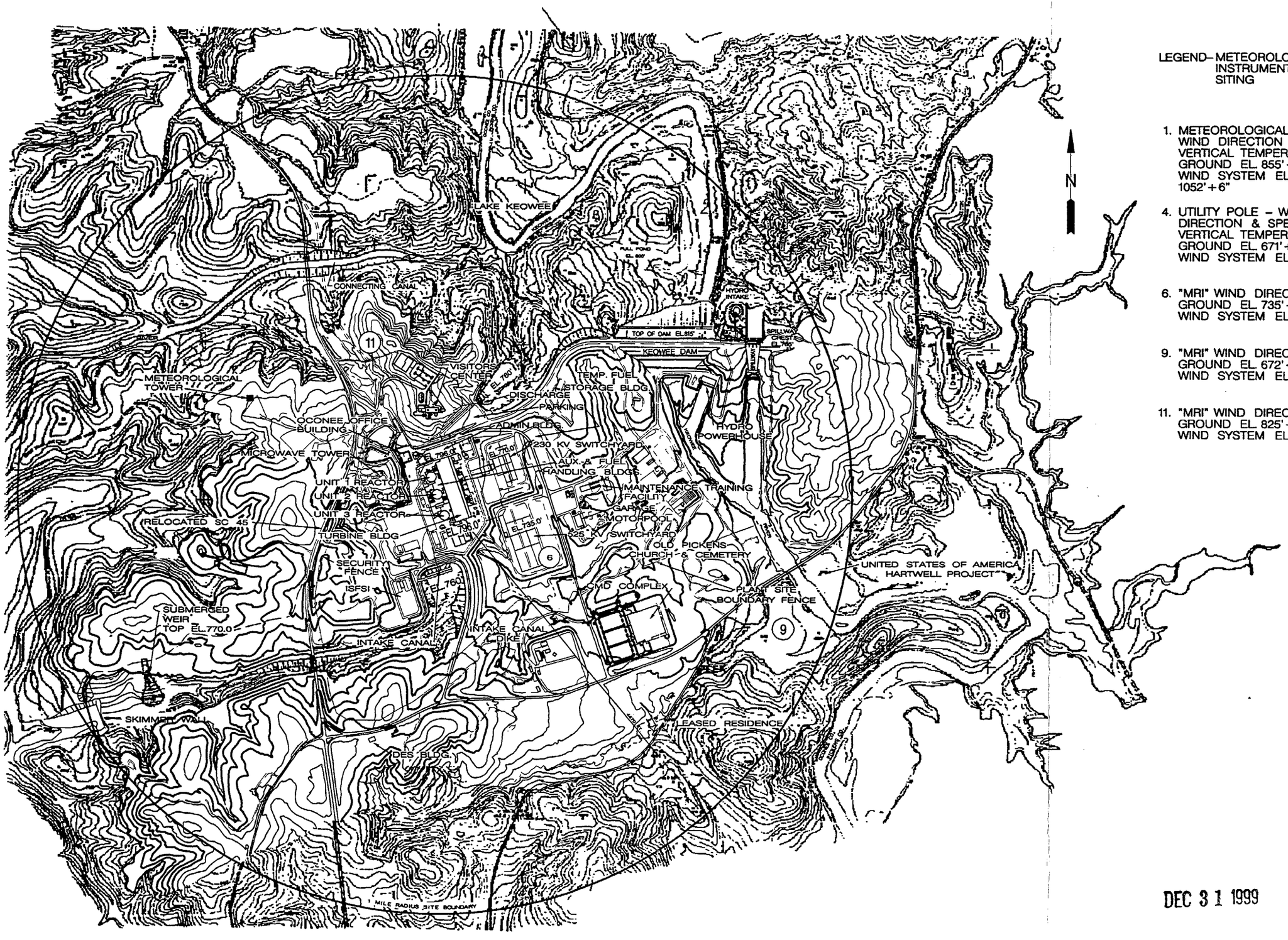
Figure 2–4

Site Plan



LEGEND– METEOROLOGICAL INSTRUMENT SITING

1. METEOROLOGICAL TOWER
   WIND DIRECTION & SPEED
   VERTICAL TEMPERATURE
   GROUND EL. 855'+8"
   WIND SYSTEM EL. 888'+6" & 1052'+6"

4. UTILITY POLE – WIND DIRECTION & SPEED
   VERTICAL TEMPERATURE
   GROUND EL. 671'+0"
   WIND SYSTEM EL. 717'+0"

6. "MRI" WIND DIRECTION & SPEED
   GROUND EL. 735'+0"
   WIND SYSTEM EL. 741'+0"

9. "MRI" WIND DIRECTION & SPEED
   GROUND EL. 672'+0"
   WIND SYSTEM EL. 678'+0"

11. "MRI" WIND DIRECTION & SPEED
    GROUND EL. 825'+0"
    WIND SYSTEM EL. 835'+0"

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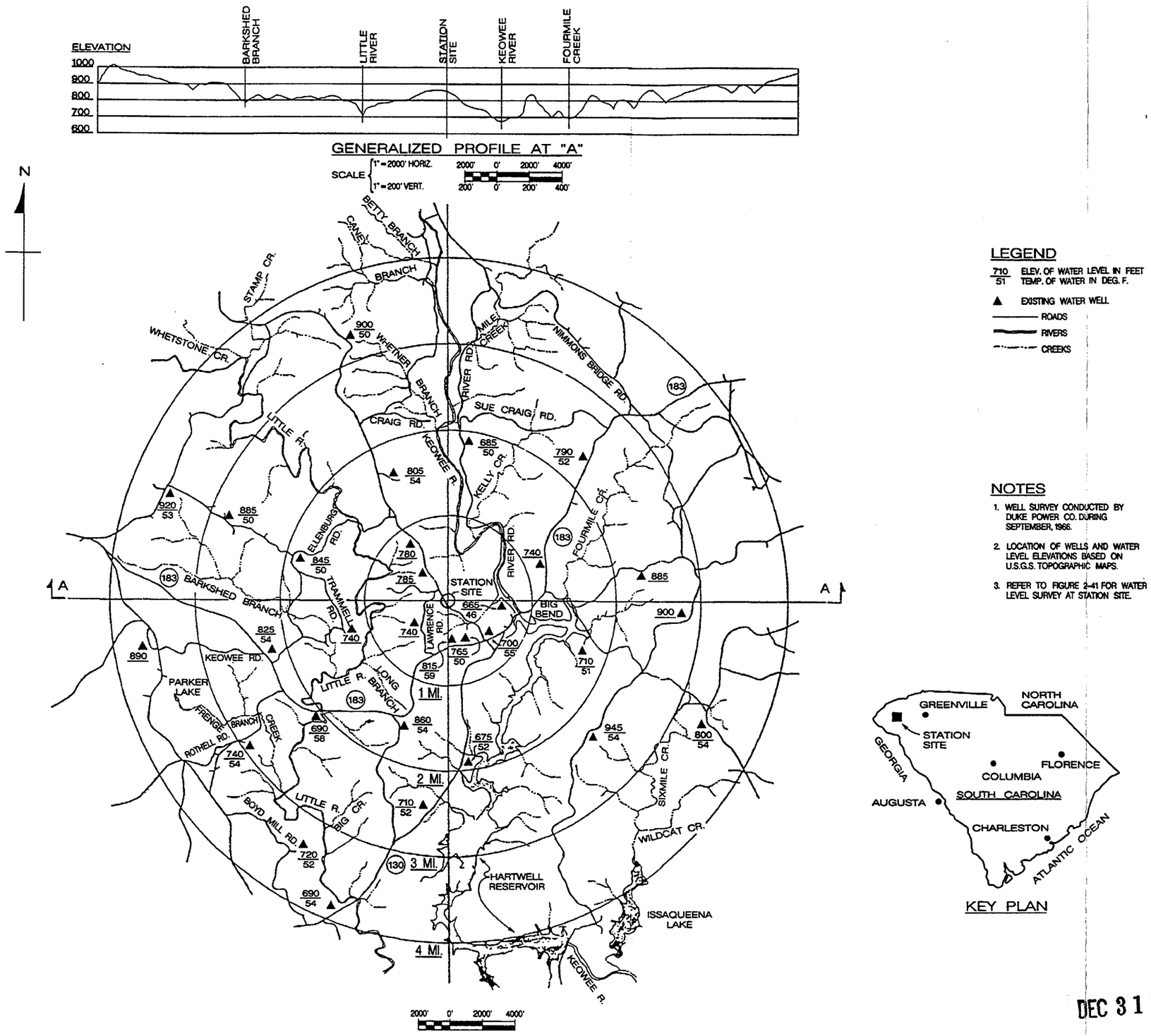
Figure 2–32
Plot Plan and Site Boundary



LEGEND

710/51 ELEV. OF WATER LEVEL IN FEET / TEMP. OF WATER IN DEG. F.

▲ EXISTING WATER WELL

ROADS

RIVERS

CREEKS

NOTES

1. WELL SURVEY CONDUCTED BY DUKE POWER CO. DURING SEPTEMBER, 1966.
2. LOCATION OF WELLS AND WATER LEVEL ELEVATIONS BASED ON U.S.G.S. TOPOGRAPHIC MAPS.
3. REFER TO FIGURE 2-41 FOR WATER LEVEL SURVEY AT STATION SITE.

KEY PLAN

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Figure 2-40
Aereal Groundwater Survey

FIELD PERMEABILITY TESTING

The tests were run according to the Bureau of Reclamation's Field Permeability Tests, Designation E–19. The immediate vicinity of each of the exploratory borings were selected as the locations for the wells: NA–4, NA–11A, NA–13 and NA–15 (Figure 2–65). Two 8 in. diameter holes were drilled at each location, to the refusal of the auger used. The NA–4 test wells were drilled with a 27 in. auger. Generally, the test wells were within 20 ft. of the exploratory borings.

The wells were prepared with care in order to cause as little disturbance to the surrounding soil as possible. No water was encountered in any of the wells. After the wells were excavated, the sides and bottoms were lightly cleaned where necessary, and the loose soil was removed from the bottom.

After cleaning, all wells were backfilled with 3/8 in. to Number 4 size crushed stone and covered with plastic sheets until time of testing. The equipment used for these permeability tests is shown to the right. each 50 gallon drum was calibrated in increments of 1/16 of an inch change in water level which corresponds to 0.0142 cubic feet of water.

For each test the permeability equipment, as shown, was set up, the crushed stone was removed to a depth of approximately 1 ft. in the well from the ground surface and the Robert's Type valve float bob was adjusted so that a water level would be maintained constant at about a 6 in. depth. All depths from the ground surface were measured from a baseline string stretched across the hole at ground level. The drum was filled with water and the test started. Water and ground temperatures were taken and recorded at varied time intervals. Readings of water level (to the nearest 1/16 of an inch) and time (to the nearest minute) were taken throughout the test. Plots of cumulative water volume versus time were prepared during each test. In general, the dry soil at the start of the test absorbed water at a comparatively high rate, but as the soil below the test became saturated, the rate decreased to a point where it was practically constant. When this occurred, as evidenced by the plotted points on thecurve falling on practically a straight line for several hours, the tests were discontinued. This data is available but has not been included on the test summary. The slope of the straight line gave the rate of flow to be used in computations of coefficient of permeability, k. Figure 2–43 shows the formulas used for determining the coefficient of permeability, k and Table 2–93 summaries the results of the test.

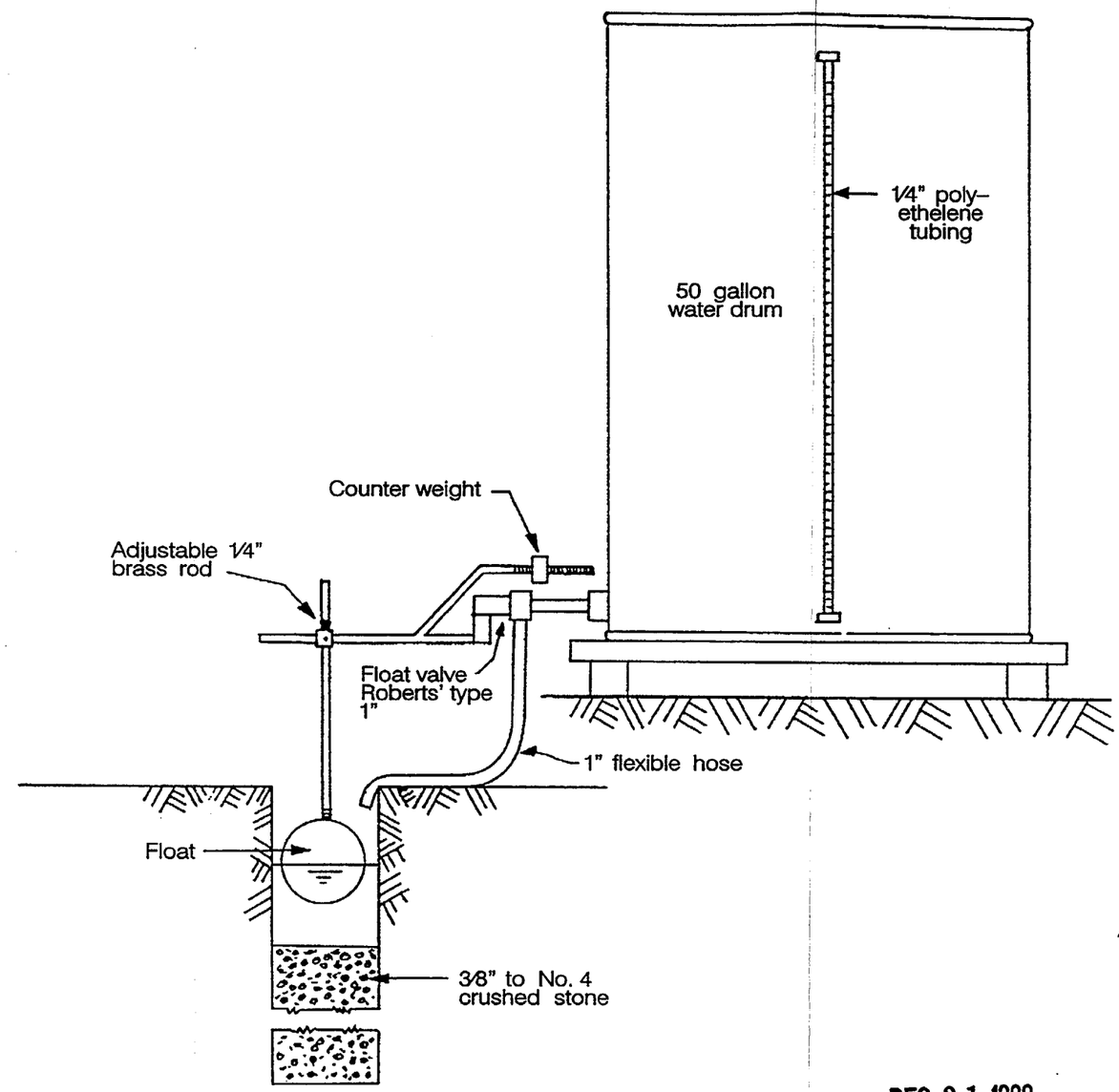

Figure 2-42
Well Permeameter Test Apparatus

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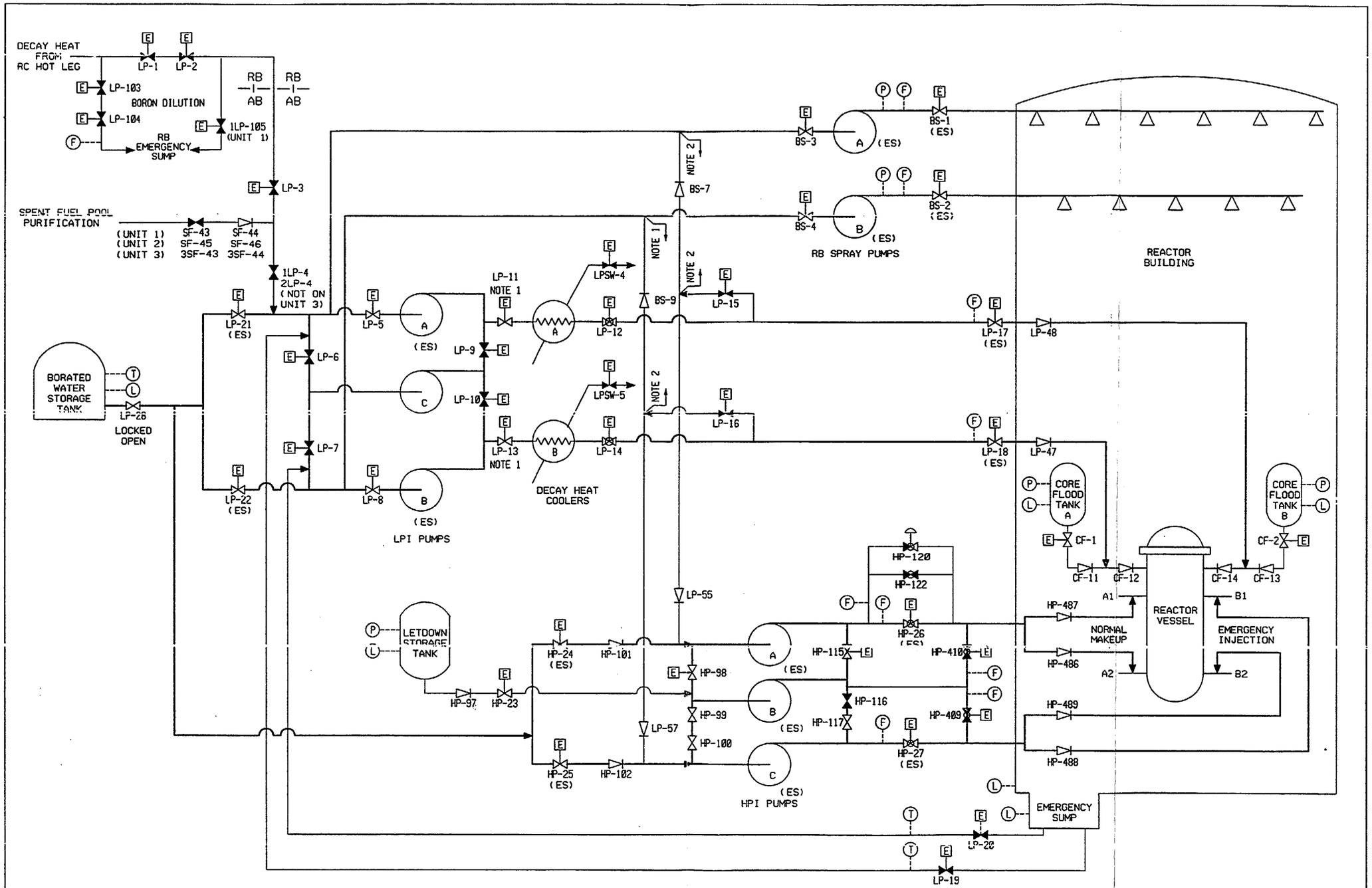

NOTES:
1. LP-11 & LP-13 ARE MANUAL ON UNIT # 3.
2. THE R.B. SPRAY TIE-IN CONNECTION SHOWN IS FOR UNIT 1 & 3 ONLY.

LEGEND
- SHUTOFF VALVE
- FLOW CONTROL VALVE
- CHECK VALVE (ALL TYPES)
- RELIEF VALVE
- NORMALLY OPEN
- NORMALLY CLOSED
- NORMALLY THROTTLED
- F-FLOW, L-LEVEL, P-PRESSURE, T-TEMPERATURE
- E-ELECTRIC, H-HYDRAULIC, P-PISTON (PNEUMATIC), S-SOLENOID
- DIAPHRAGM (PNEUMATIC)
- (ES)-RECEIVES ENGINEERED SAFEGUARD SIGNAL

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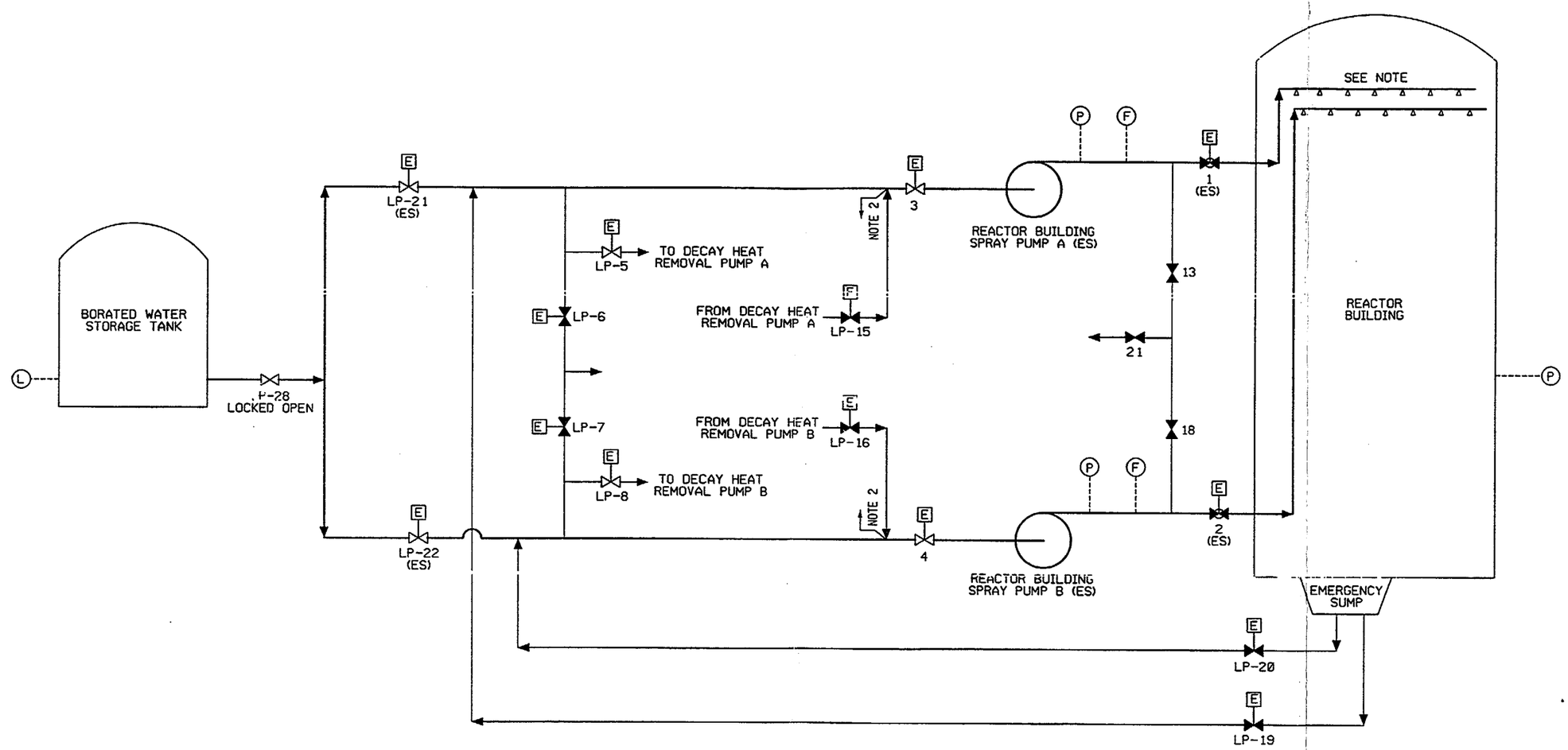
TYPICAL FOR UNITS 1, 2, & 3.

Figure 6-1
Flow Diagram of Emergency Core Cooling System



NOTES

1. REFER TO OFD-103A-1.1, OFD-103A-2.1 AND OFD-103A-3.1 FOR THE EXACT NUMBER OF REACTOR BUILDING SPRAY NOZZLES PER HEADER.
2. THE R.B. SPRAY TIE-IN CONNECTION SHOWN IS FOR UNIT 1 & 3 ONLY.

ERN: OX001I81

LEGEND

- SHUTOFF VALVE
- FLOW CONTROL VALVE
- CHECK VALVE (ALL TYPES)
- RELIEF VALVE
- NORMALLY OPEN
- NORMALLY CLOSED
- NORMALLY THROTTLED
- THREE WAY VALVE
- F-FLOW, L-LEVEL, P-PRESSURE, T-TEMPERATURE, R-RADIATION MONITOR
- E-ELECTRIC, H-HYDRAULIC, P-PISTON (PNEUMATIC), S-SOLENOID
- DIAPHRAGM (PNEUMATIC)
- (ES)-RECEIVES ENGINEERED SAFEGUARD SIGNAL

THIS FSAR FIGURE WAS CREATED FROM SUMMARY FLOW DIAGRAM OSFD-121A-1. FOR COMPLETE SYSTEM DESIGN INFORMATION, REFER TO THE FOLLOWING FLOW DIAGRAMS.

OFD-102A-1.1,-2.1,-3.1	R.B. SPRAY PUMPS SUCTION.
OFD-102A-1.2,-2.2,-3.2	DECAY HEAT REMOVAL COOLER DISCHARGE.
OFD-103A-1.1,-2.1,-3.1	R.B. SPRAY PUMPS AND DISCHARGE.

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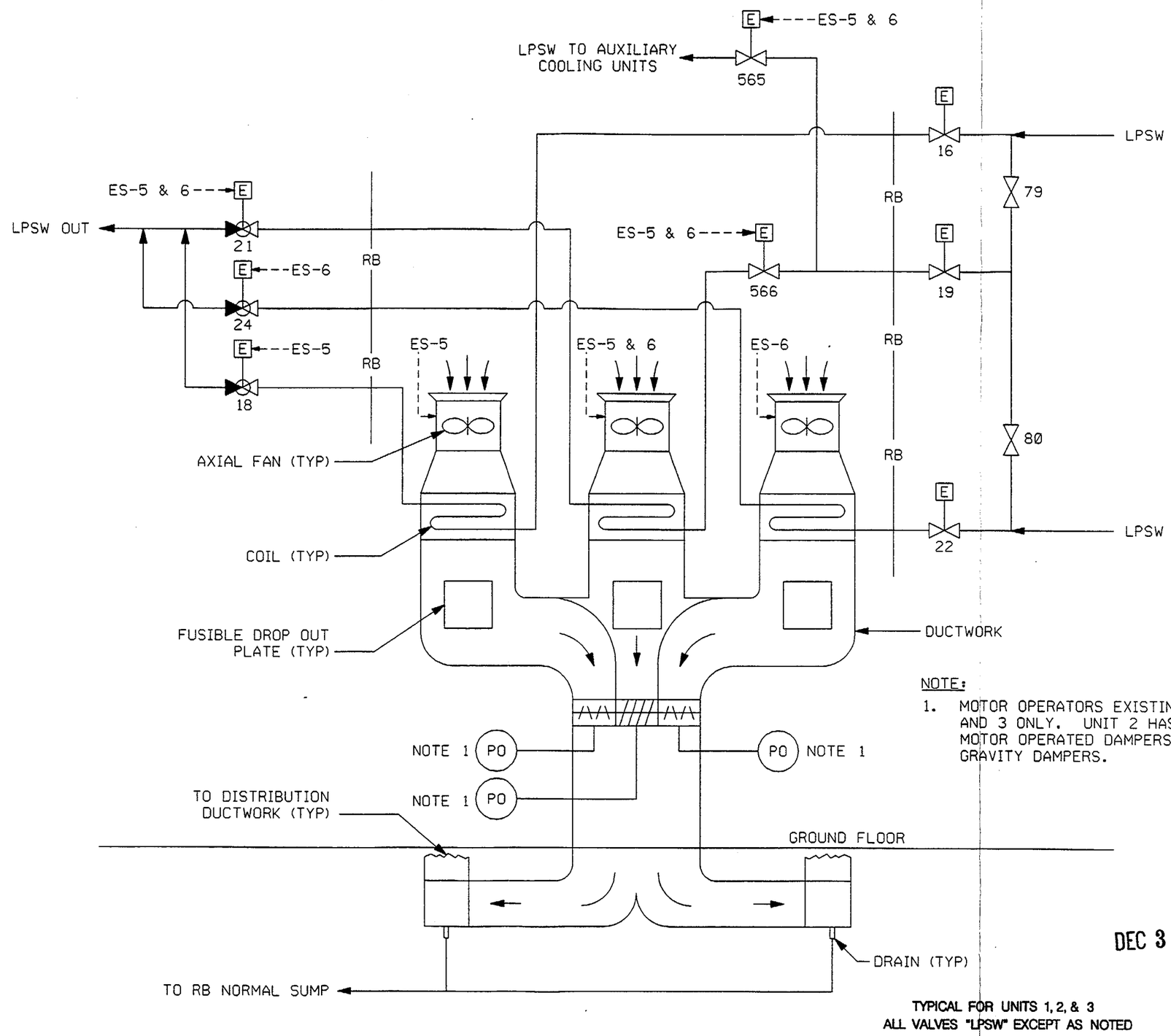
TYPICAL FOR UNITS 1, 2 & 3
ALL VALVES "BS" EXCEPT AS NOTED

Figure 6-2
Reactor Building Spray System



NOTE:

1. MOTOR OPERATORS EXISTING ON UNIT 1 AND 3 ONLY. UNIT 2 HAS REPLACED MOTOR OPERATED DAMPERS WITH GRAVITY DAMPERS.

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TYPICAL FOR UNITS 1, 2, & 3
ALL VALVES "LPSW" EXCEPT AS NOTED

Figure 6-3
Reactor Building Cooling Schematic

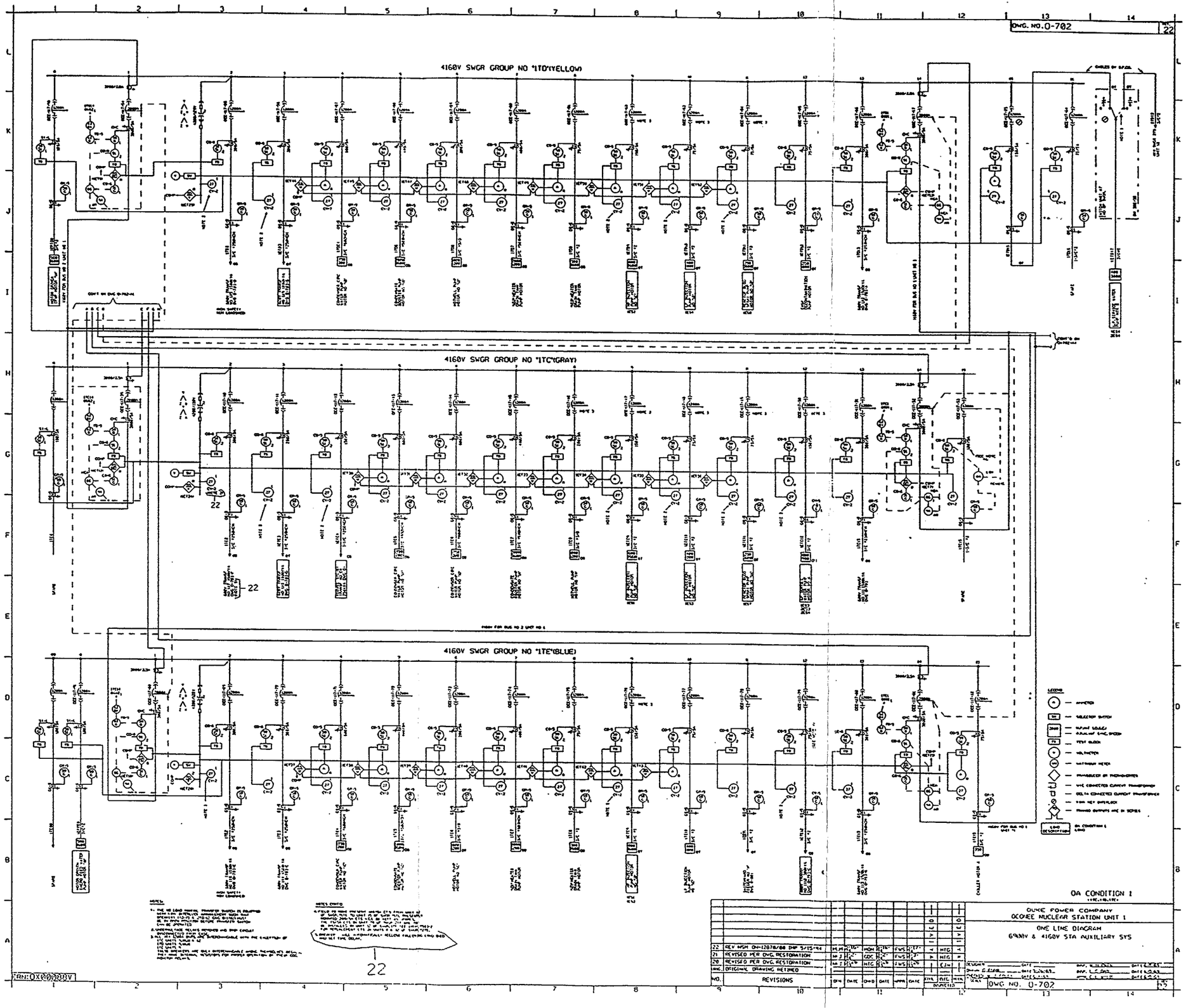

Figure 8-3 (Part 1 of 2)
Typical 6900 Volt and 4160
Volt Unit Auxiliary
Single Line Diagram

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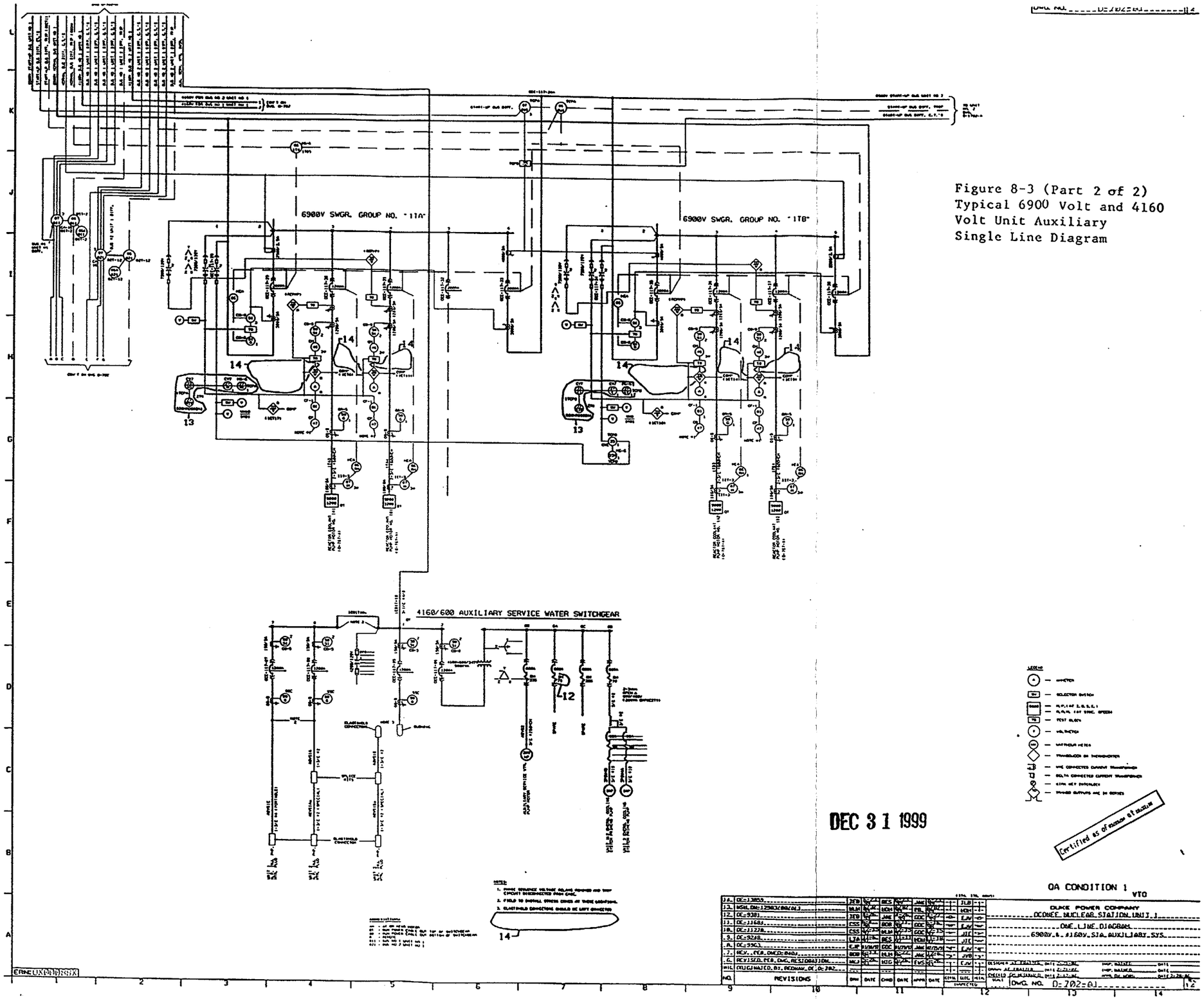

Figure 8-3 (Part 2 of 2)
Typical 6900 Volt and 4160
Volt Unit Auxiliary
Single Line Diagram

DWG. NO. 0-703-G

FIGURE 8-4
TYPICAL 600 VOLT AND
208 VOLT ESG AUXILLARIES
SINGLE LINE DIAGRAM

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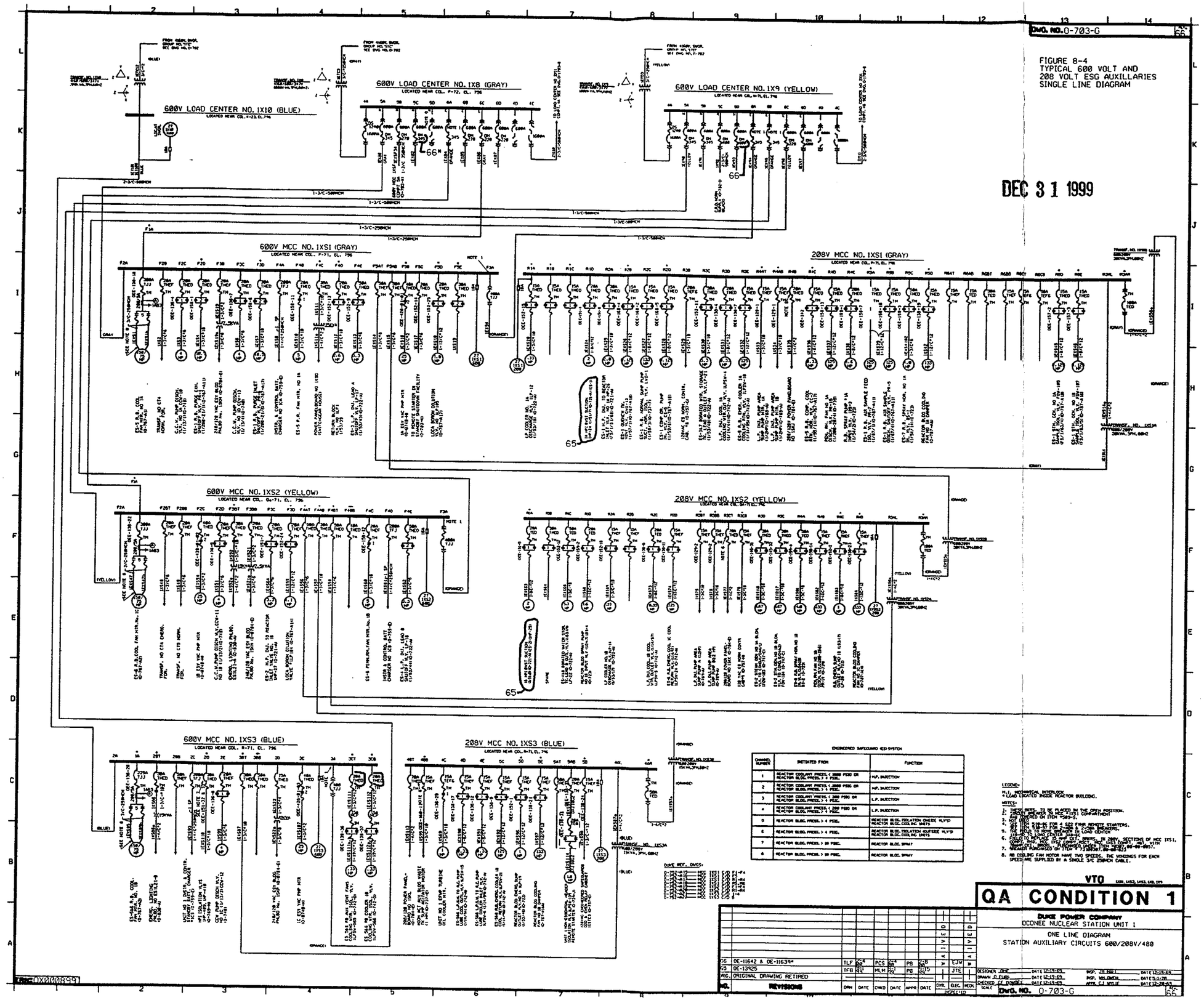

ENGINEERED SAFEGUARD ESS SYSTEM

CHANNEL NUMBER	INITIATED FROM	FUNCTION
1	REACTOR COOLANT PRESS. < 1800 PSIG OR REACTOR BLDG. PRESS. > 4 PSIG.	H.P. INJECTION
2	REACTOR COOLANT PRESS. < 1800 PSIG OR REACTOR BLDG. PRESS. > 4 PSIG.	H.P. INJECTION
3	REACTOR COOLANT PRESS. < 200 PSIG OR REACTOR BLDG. PRESS. > 4 PSIG.	L.P. INJECTION
4	REACTOR COOLANT PRESS. < 200 PSIG OR REACTOR BLDG. PRESS. > 4 PSIG.	L.P. INJECTION
5	REACTOR BLDG. PRESS. > 4 PSIG.	REACTOR BLDG. ISOLATION CHECK VLVS REACTOR BLDG. COOLING UNITS
6	REACTOR BLDG. PRESS. > 4 PSIG.	REACTOR BLDG. ISOLATION KNIFE VLVS REACTOR BLDG. COOLING UNITS
7	REACTOR BLDG. PRESS. > 30 PSIG.	REACTOR BLDG. SPRAY
8	REACTOR BLDG. PRESS. > 30 PSIG.	REACTOR BLDG. SPRAY

LEGEND:
M.I. MECHANICAL INTERLOCK
* LOAD LOCATED INSIDE REACTOR BUILDING.

NOTES:
1. INDICATES NORMAL POSITION.
2. INDICATES NORMAL POSITION IN THE OPEN POSITION.
3. LOCATED IN ITEM "CWS-3".
4. 208V MCC 1XS1-1B FOR A SEC FWHR REMOTE STARTERS.
5. 208V MCC 1XS1-1B FOR A SEC FWHR REMOTE STARTERS.
6. 208V MCC 1XS1-1B FOR A SEC FWHR REMOTE STARTERS.
7. ALL 208V MCC 1XS1-1B FOR A SEC FWHR REMOTE STARTERS.
8. RB COOLING FAN MOTOR HAVE TWO SPEEDS. THE WINDINGS FOR EACH SPEED ARE SUPPLIED BY A SINGLE 3/C COMMON CABLE.

VTQ

QA CONDITION 1

REV.	REVISIONS	DRN	DATE	CHKD	DATE	APPR	DATE	CHG.	DES.	MOD.
66	DE-11642 & DE-11639*	TLF	8/24	PCS	8/24	PB	8/25			
65	DE-13425	TFB	4/21	MLH	4/21	PB	4/21		JTE	
REV.	ORIGINAL DRAWING RETIRED									

DUKE POWER COMPANY
OCONEE NUCLEAR STATION UNIT 1

ONE LINE DIAGRAM
STATION AUXILIARY CIRCUITS 600/208V/480

DESIGNER JBW DATE 12-19-83 ENGR. JB EWI DATE 12-19-83
DRAWN D.CLUS DATE 12-19-83 ENGR. MS.DWEN DATE 5-1-78
CHECKED JC DAVIS DATE 12-23-83 APPR. CJ WILIE DATE 12-28-83
SCALE DWG. NO. 0-703-G

OX000899

userdir\1xs2\ox000899.dgn Mar. 28, 2000 14:52:38

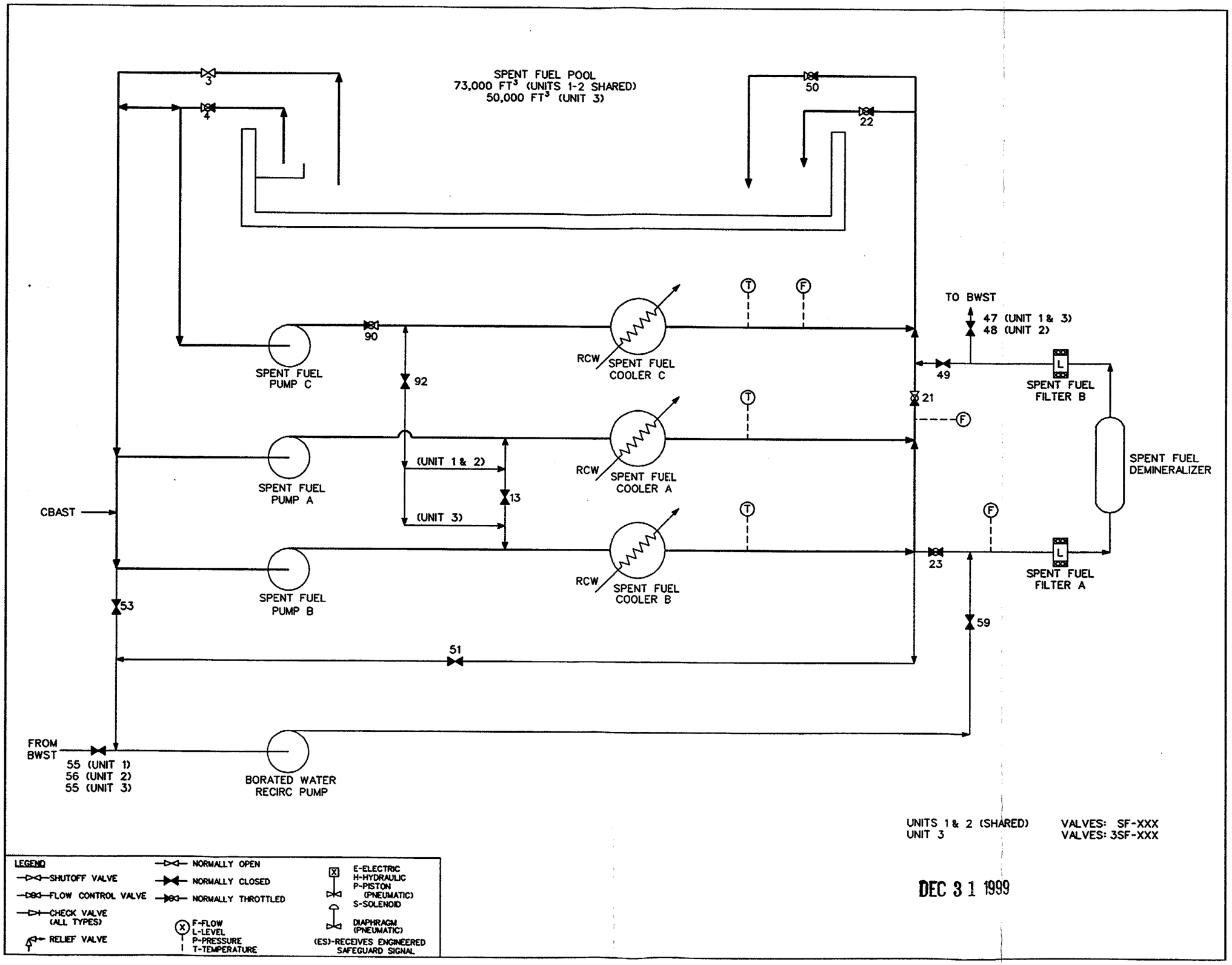

Figure 9-5
Spent Fuel Cooling System

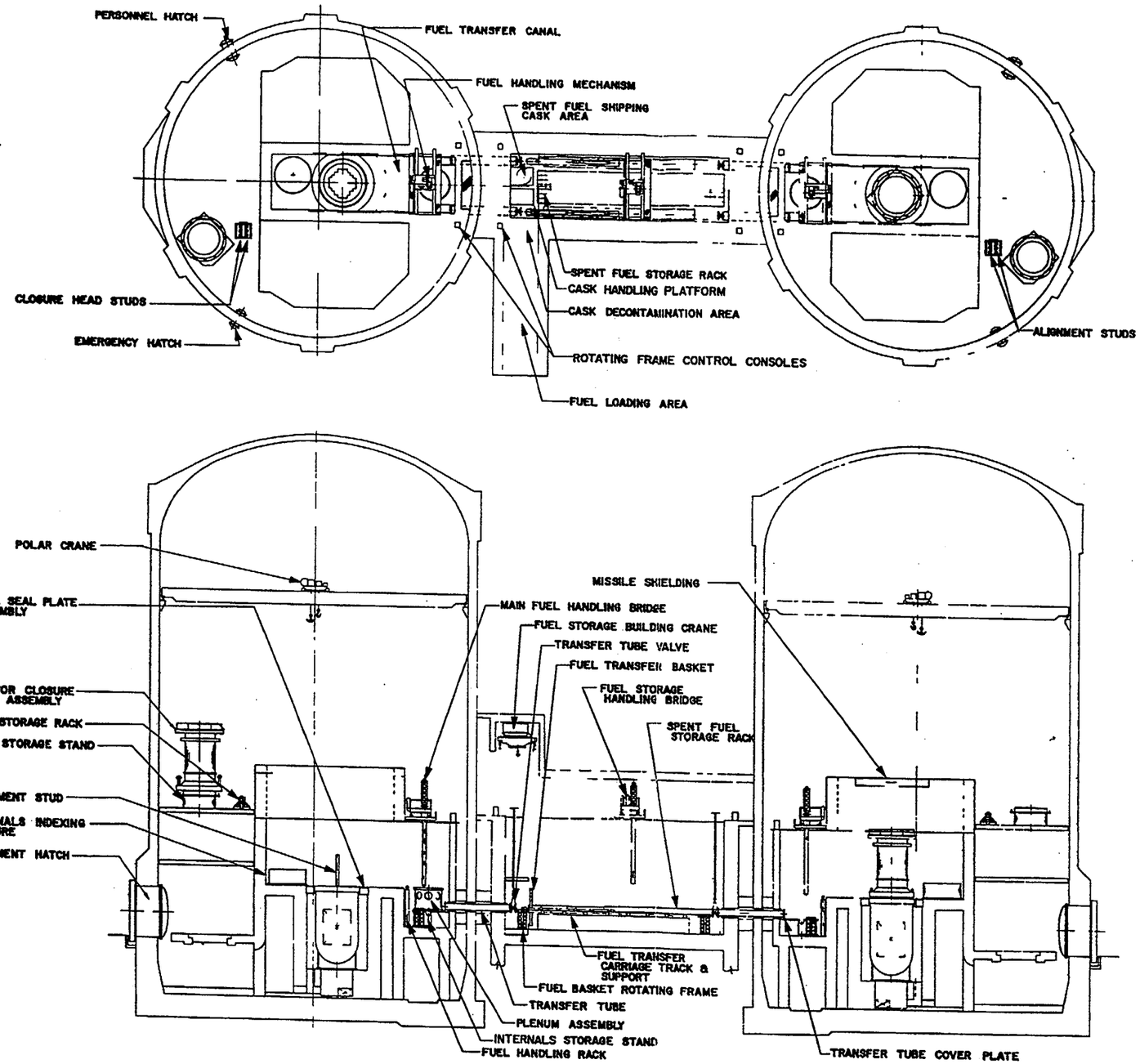

FIG. 9-7 (SHEET 1 OF 2)
FUEL HANDLING SYSTEM
UNITS 1 AND 2

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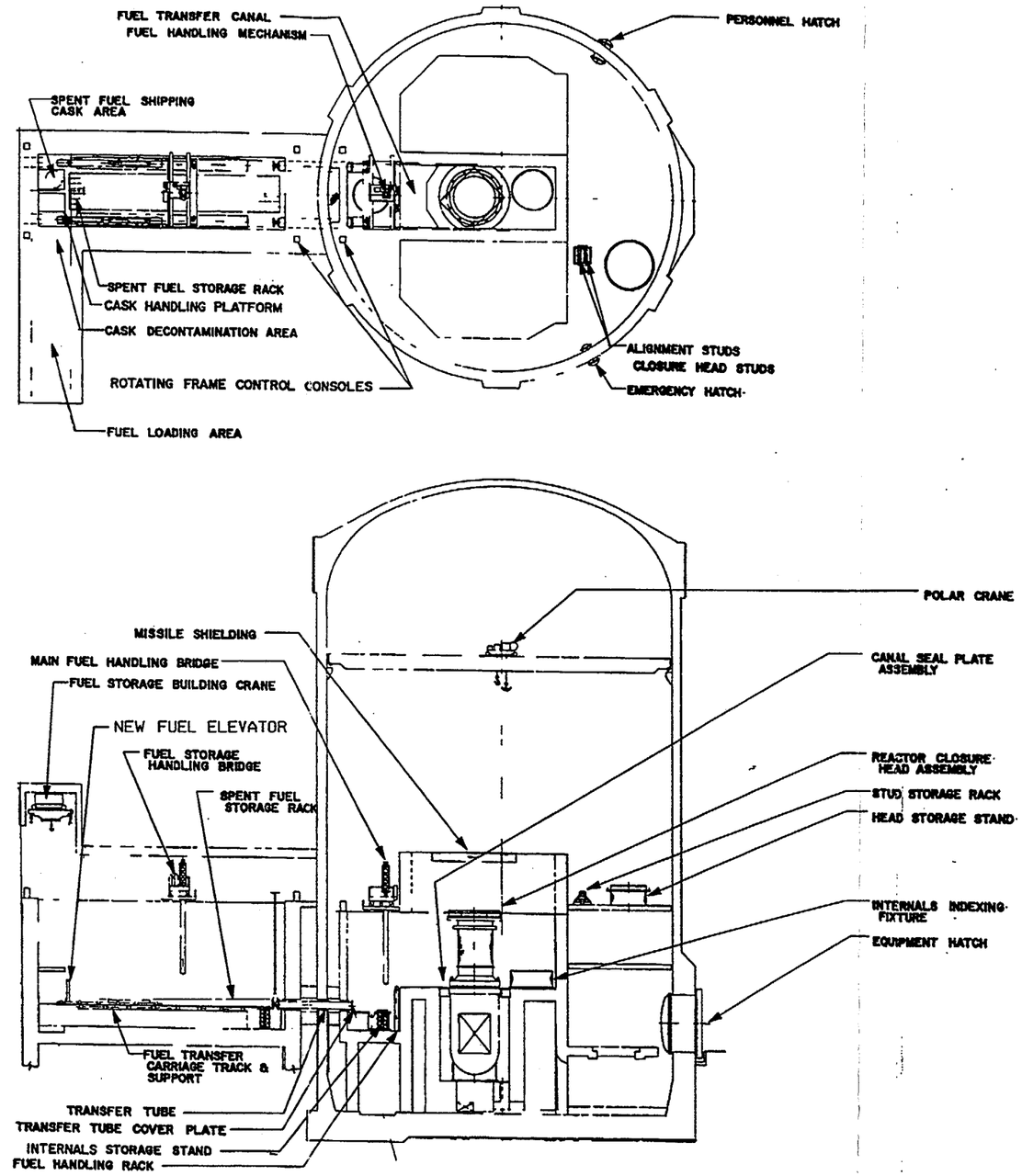

FIG. 9-7 (SHEET 2 OF 2)
FUEL HANDLING SYSTEM
UNIT 3

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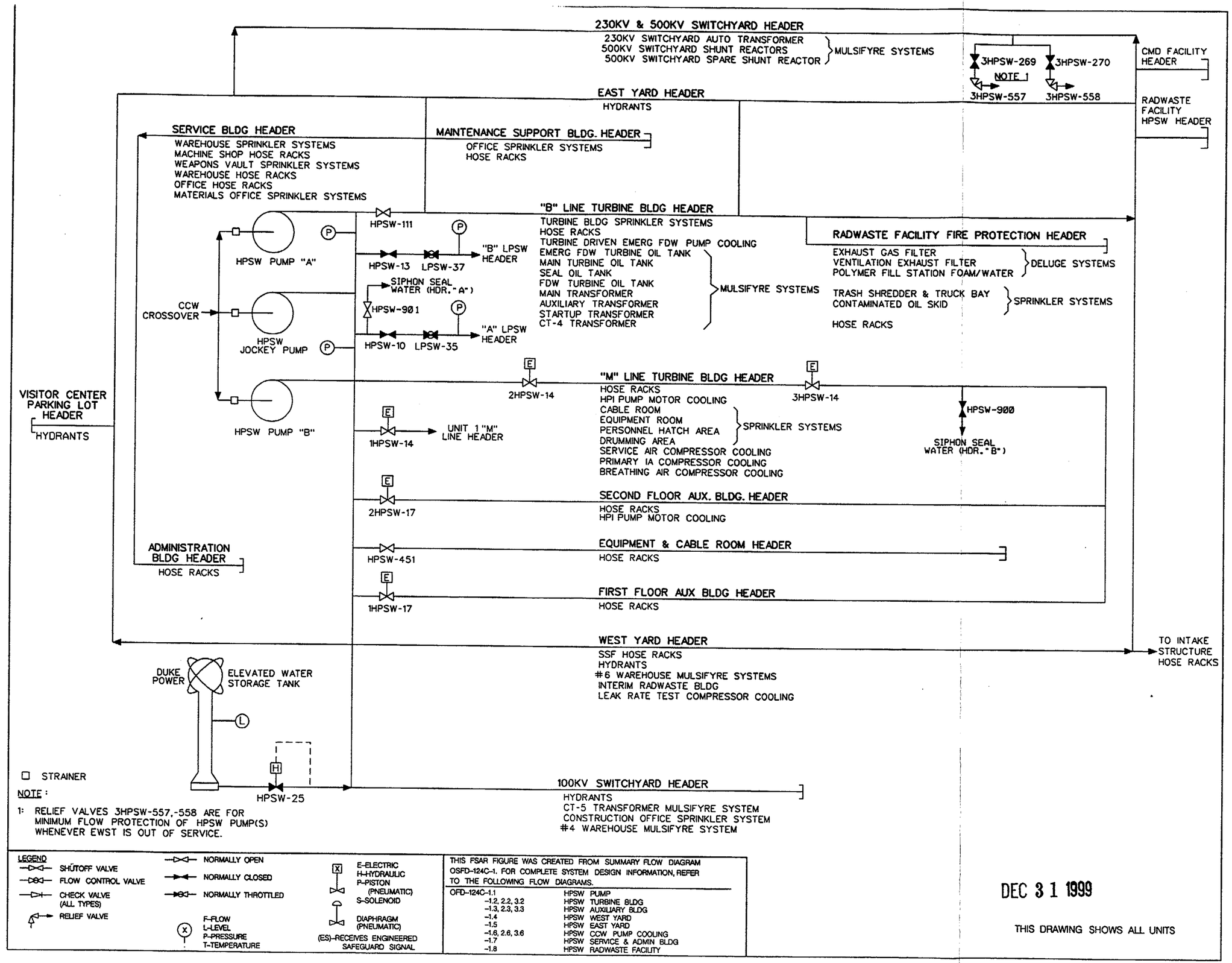

Figure 9-10
High Pressure Service Water System

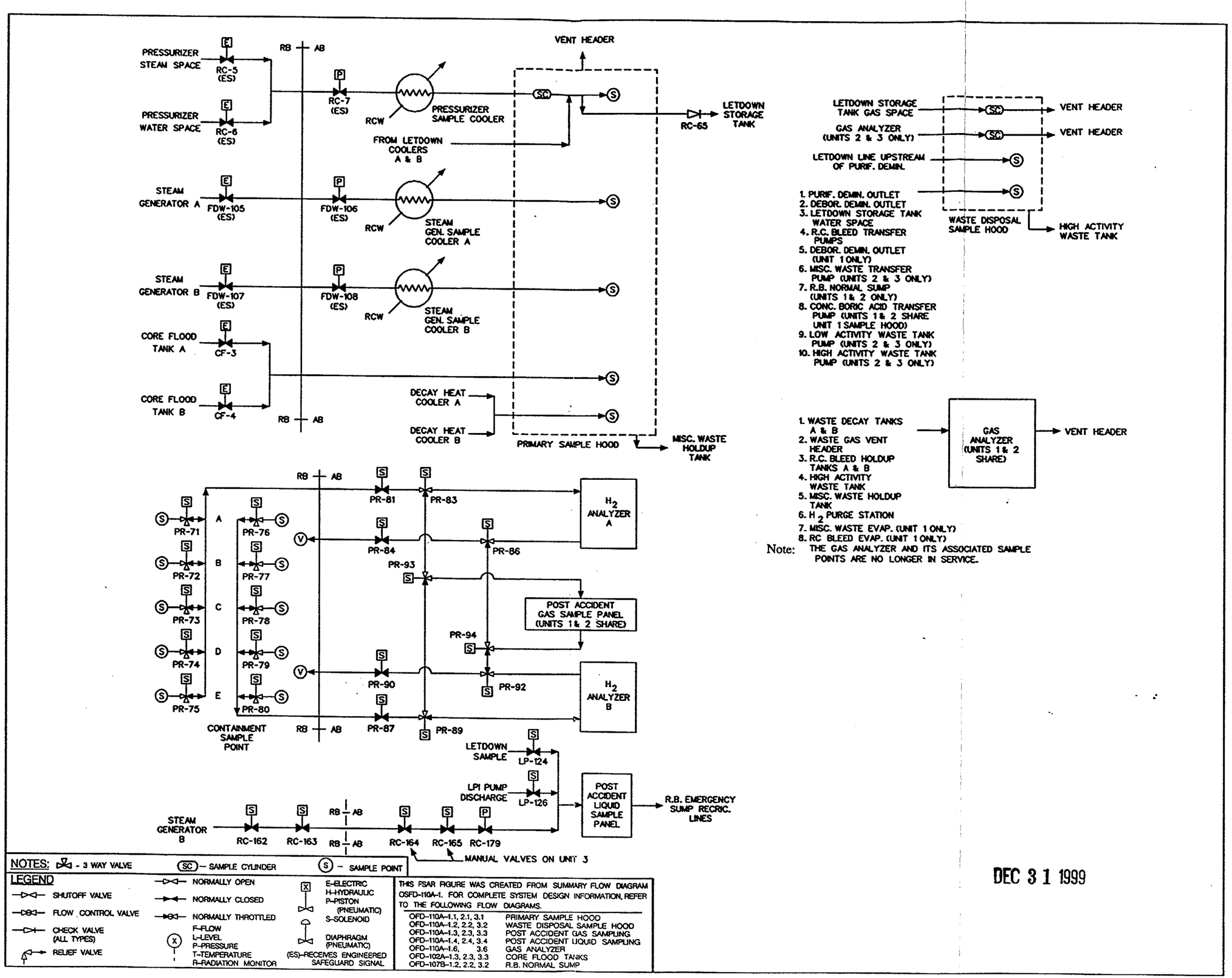

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Figure 9-15
Chemical Addition and Sampling System

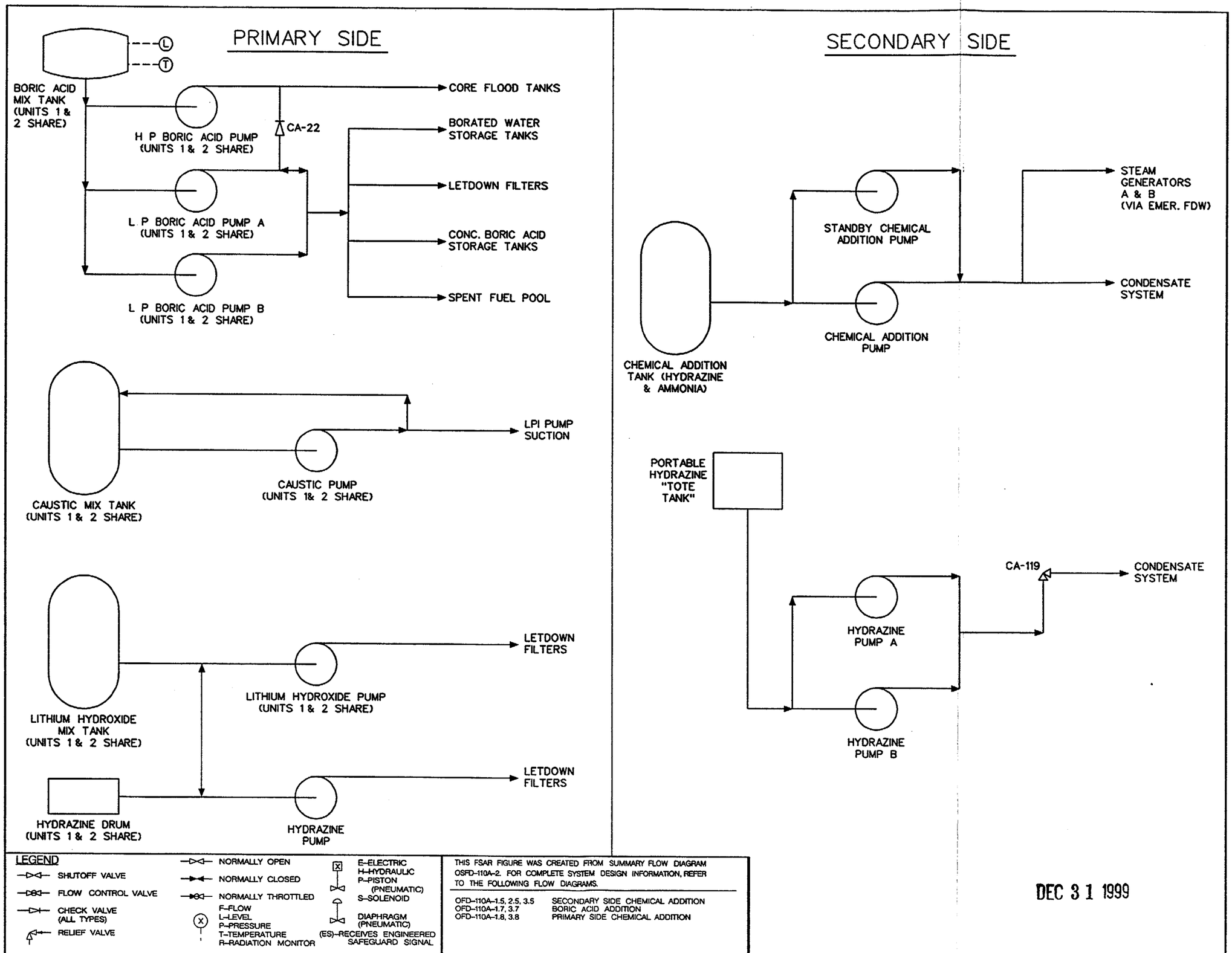
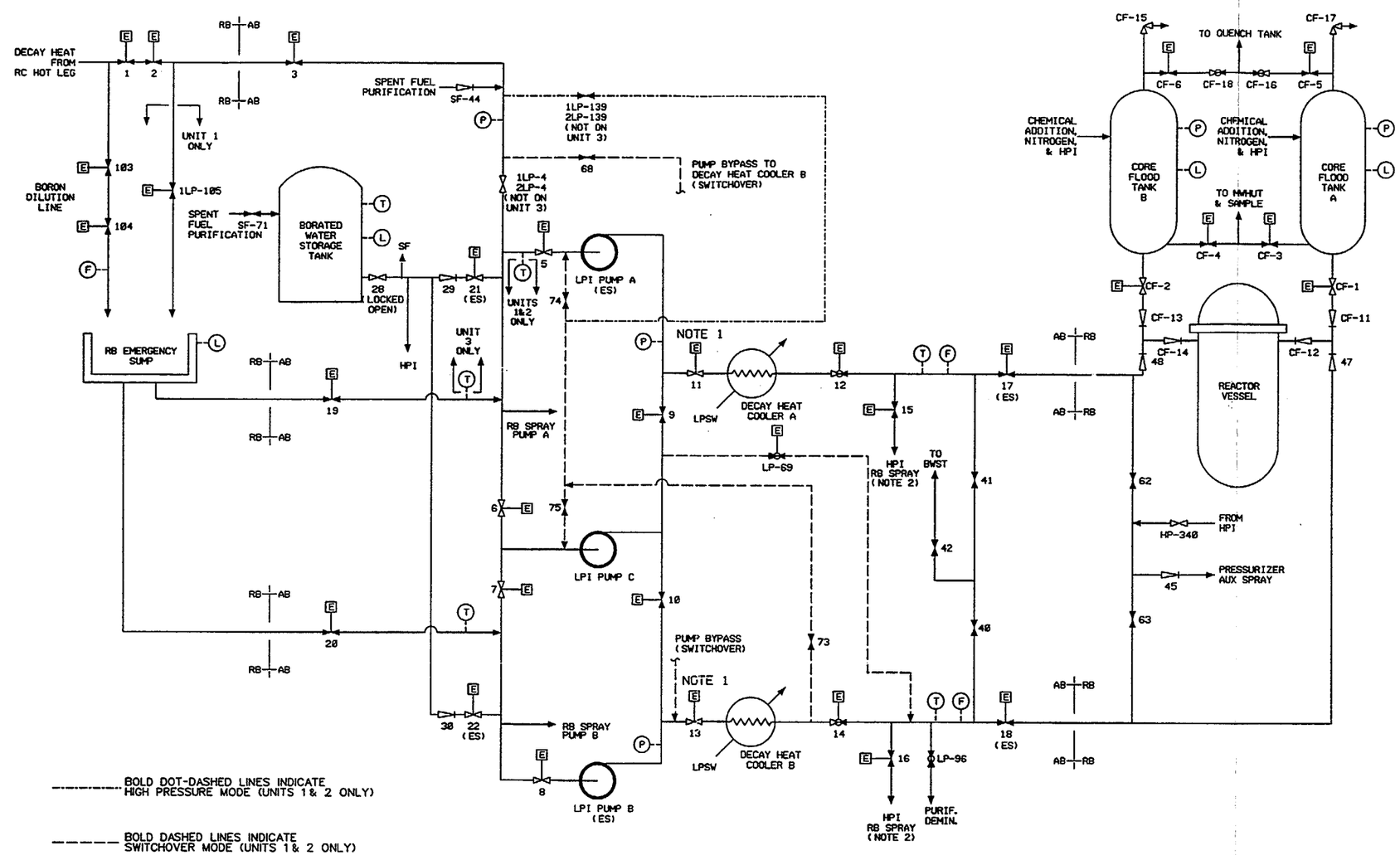


Figure 9-16
Chemical Addition and Sampling System



NOTES:

1. LP-11 & LP-13 ARE MANUAL ON UNIT # 3.
2. THE R. B. SPRAY TIE-IN CONNECTION SHOWN IS FOR UNIT 1 & 3 ONLY.

LEGEND

- SHUTOFF VALVE
- FLOW CONTROL VALVE
- CHECK VALVE (ALL TYPES)
- RELIEF VALVE
- NORMALLY OPEN
- NORMALLY CLOSED
- NORMALLY THROTTLED
- F-FLOW, L-LEVEL, P-PRESSURE, T-TEMPERATURE
- E-ELECTRIC, H-HYDRAULIC, P-PISTON (PNEUMATIC), S-SOLENOID
- DIAPHRAGM (PNEUMATIC)
- (ES)-RECEIVES ENGINEERED SAFEGUARD SIGNAL

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TYPICAL FOR UNITS 1, 2, 3
ALL VALVES "LP" EXCEPT AS NOTED

Figure 9-19
Low Pressure Injection System

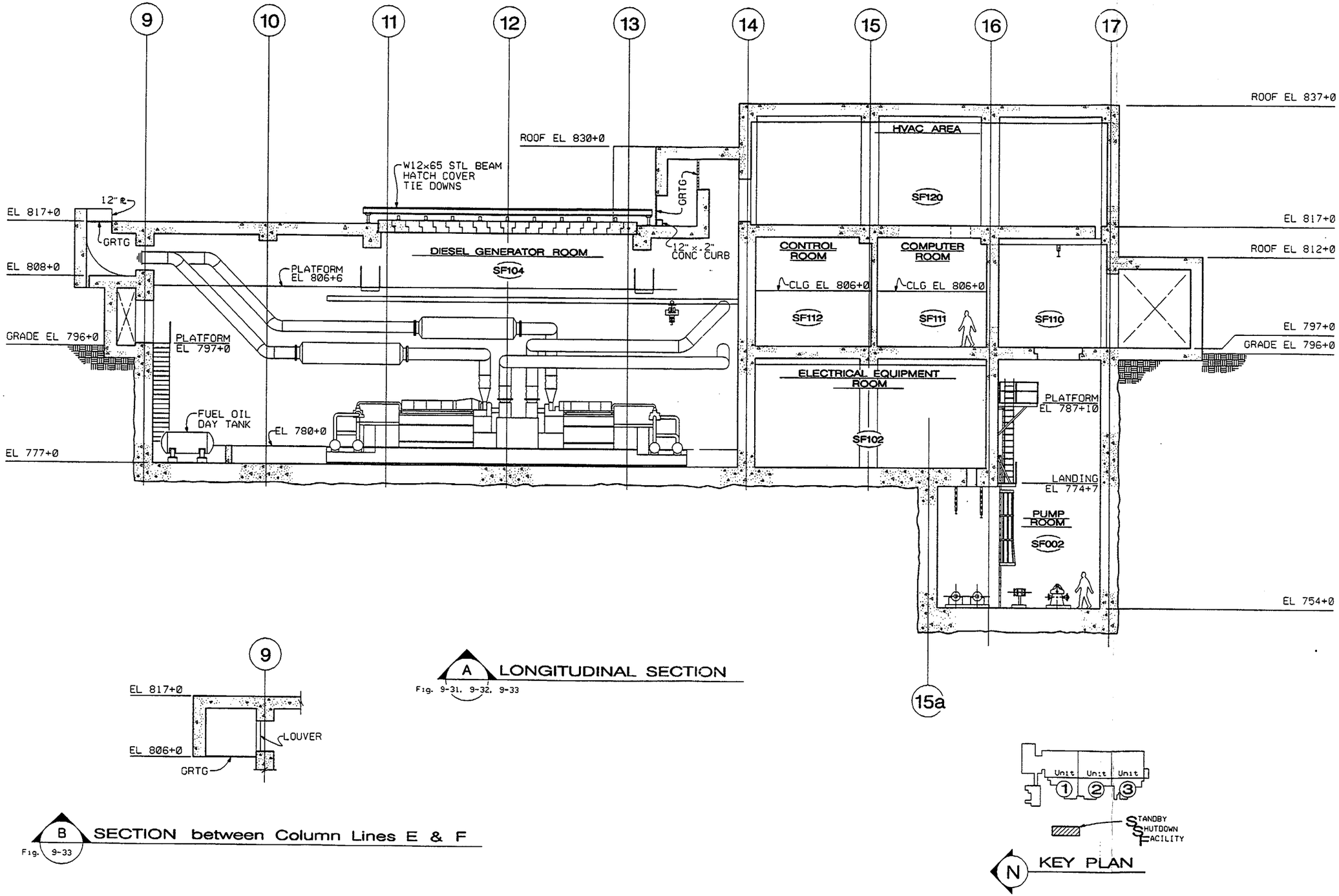

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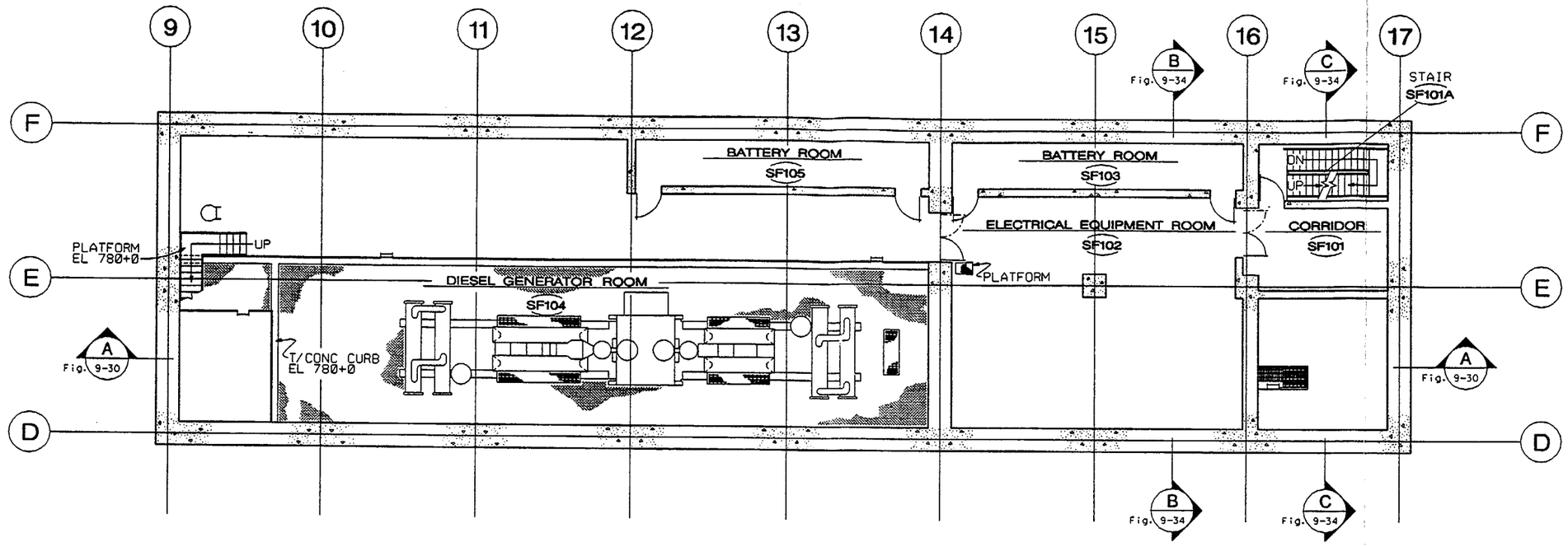
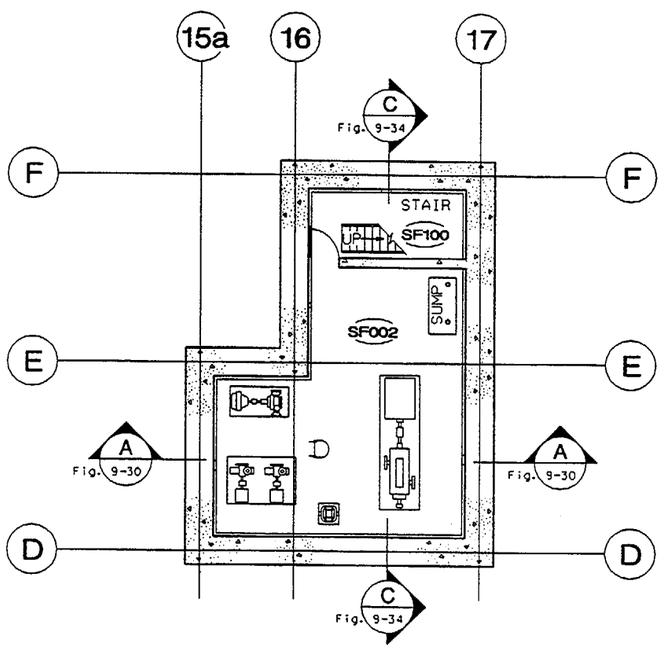
Figure 9-30.
SSF General Arrangements Longitudinal Section



PLAN @ EL. 777+0



PLAN @ EL. 754+0

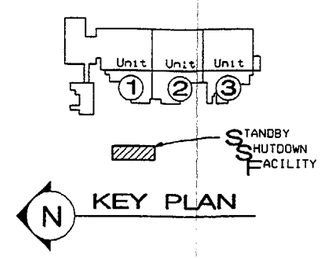


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Figure 9-31.
SSF General Arrangements Plan Elevation 777' and 754'

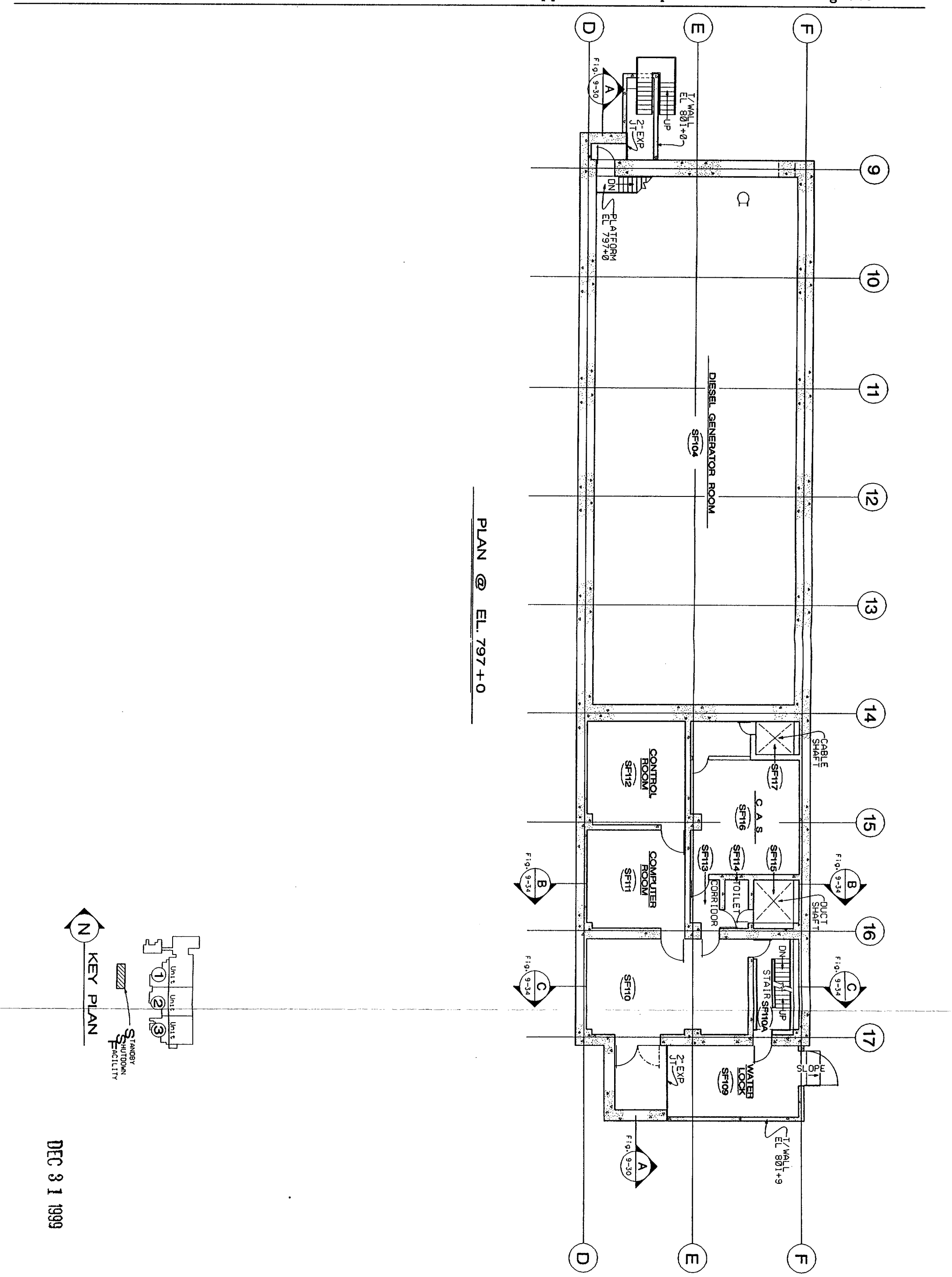

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Figure 9-32.
SSF General Arrangements Plan Elevation 797+0

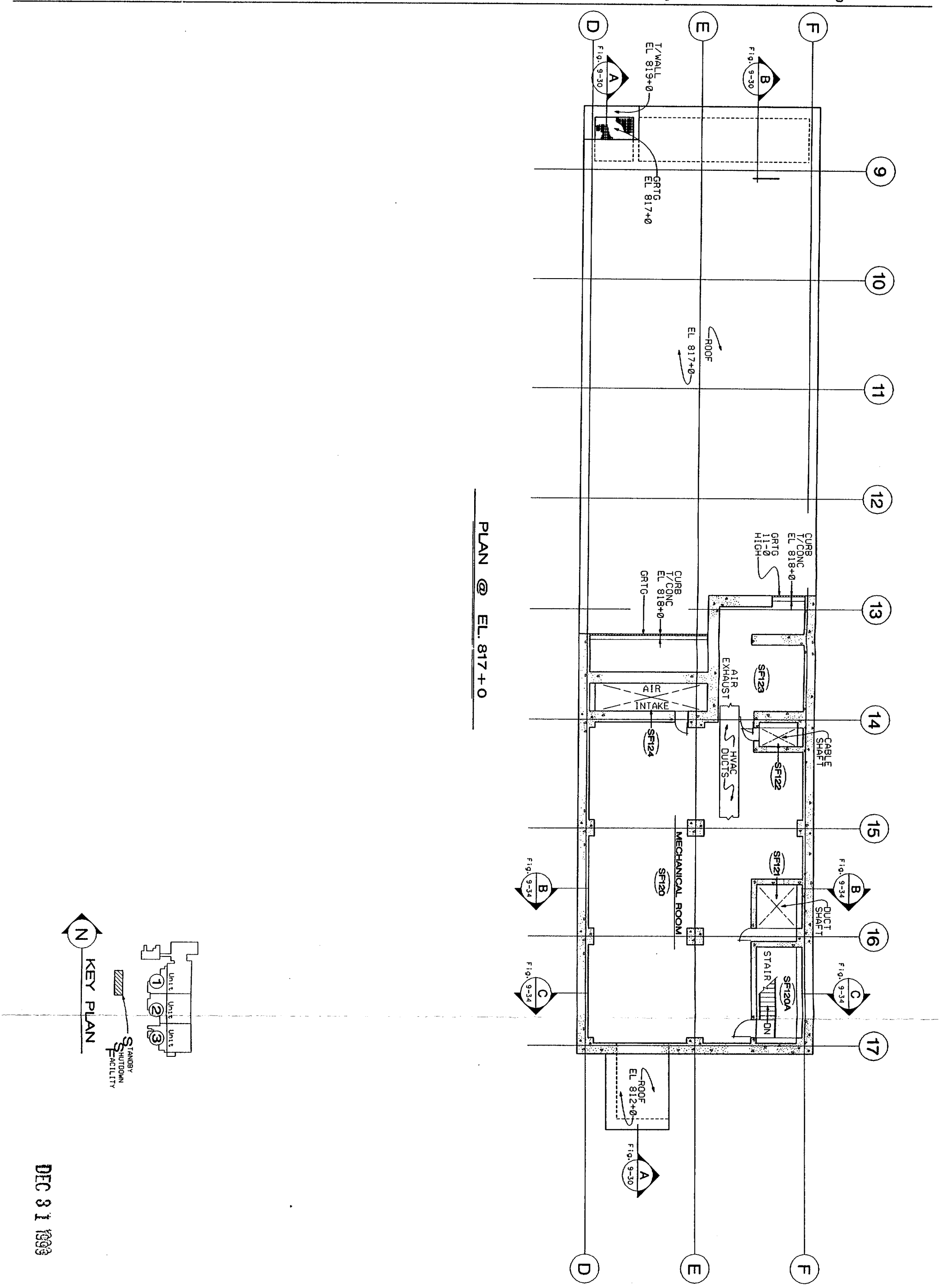
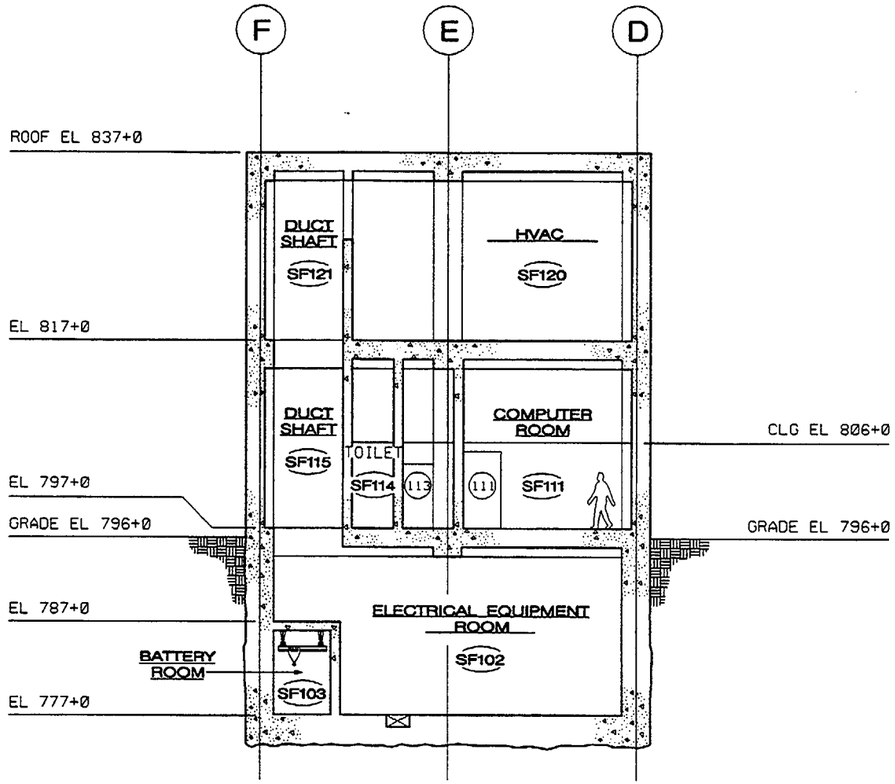
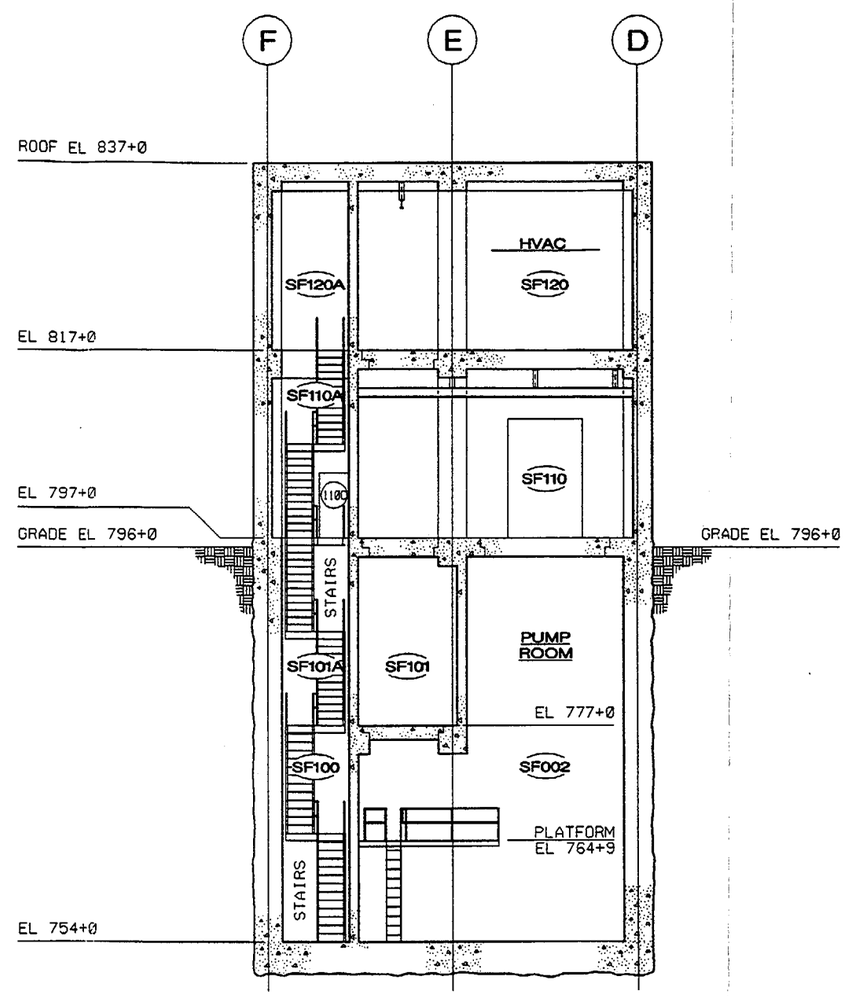


Figure 9-33.
SSF General Arrangements Plan Elevation 817+0



B TRANSVERSE SECTION

Fig. 9-31, 9-32, 9-33



C TRANSVERSE SECTION

Fig. 9-31, 9-32, 9-33

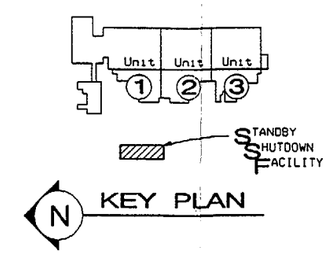


Figure 9-34.
SSF General Arrangements Transverse Section

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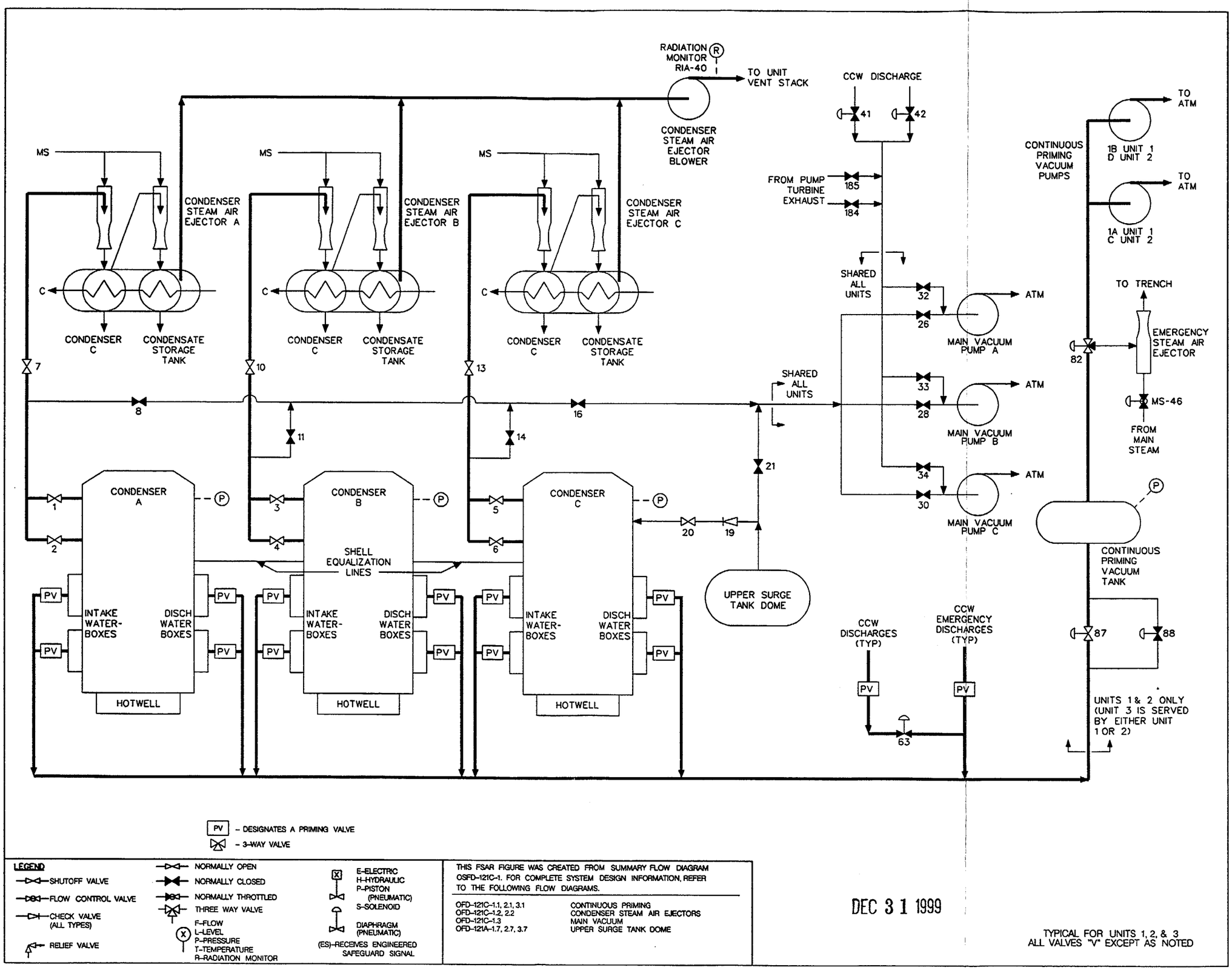
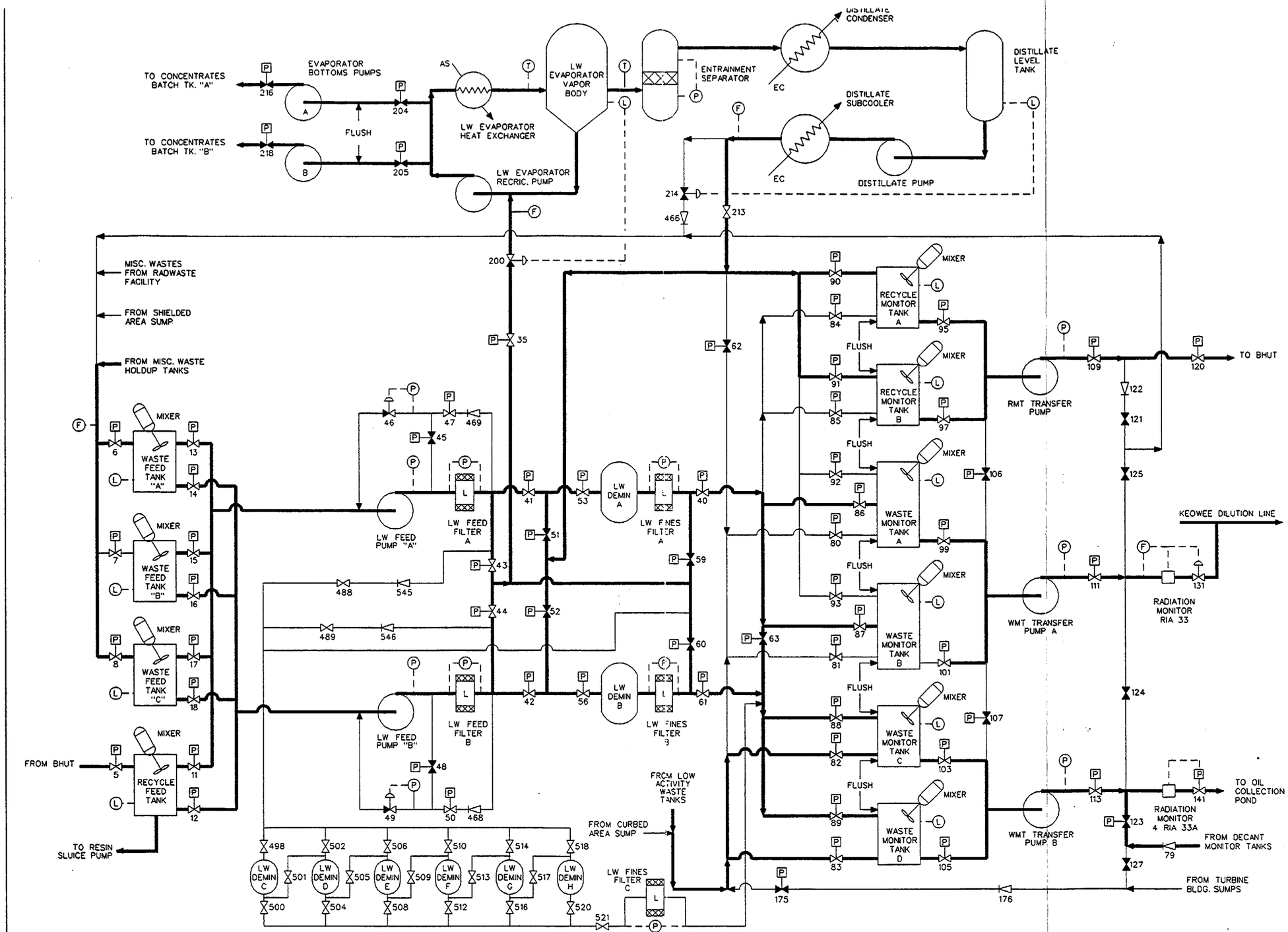


Figure 10-5
Vacuum System



LEGEND

- SHUTOFF VALVE
- FLOW CONTROL VALVE
- CHECK VALVE (ALL TYPES)
- RELIEF VALVE
- NORMALLY OPEN
- NORMALLY CLOSED
- NORMALLY THROTTLED
- F-FLOW, L-LEVEL, P-PRESSURE, T-TEMPERATURE
- E-ELECTRIC, H-HYDRAULIC, P-PISTON (PNEUMATIC), S-SOLENOID
- DIAPHRAGM (PNEUMATIC)
- (ES)-RECEIVES ENGINEERED SAFEGUARD SIGNAL

THIS FSAR FIGURE WAS CREATED FROM SUMMARY FLOW DIAGRAM OSFD-117B-1. FOR COMPLETE SYSTEM DESIGN INFORMATION, REFER TO THE FOLLOWING FLOW DIAGRAMS.

OFD-117B-1.1	FEED TANKS	OFD-117B-1.6	WMT C & D
OFD-117B-1.2	FEED PUMPS AND FILTERS	OFD-117B-1.7	RMT A & B
OFD-117B-1.3	EVAPORATOR	OFD-117B-1.8	SHIELDED AREA SUMP
OFD-117B-1.4	DEMINERALIZERS	OFD-117B-1.9	CURBED AREA SUMP
OFD-117B-1.5	WMT A & B	OFD-117B-1.10	LW DEMINS. C THRU H

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ALL VALVES "LW" EXCEPT AS NOTED

Figure 11-2
Liquid Waste Disposal System

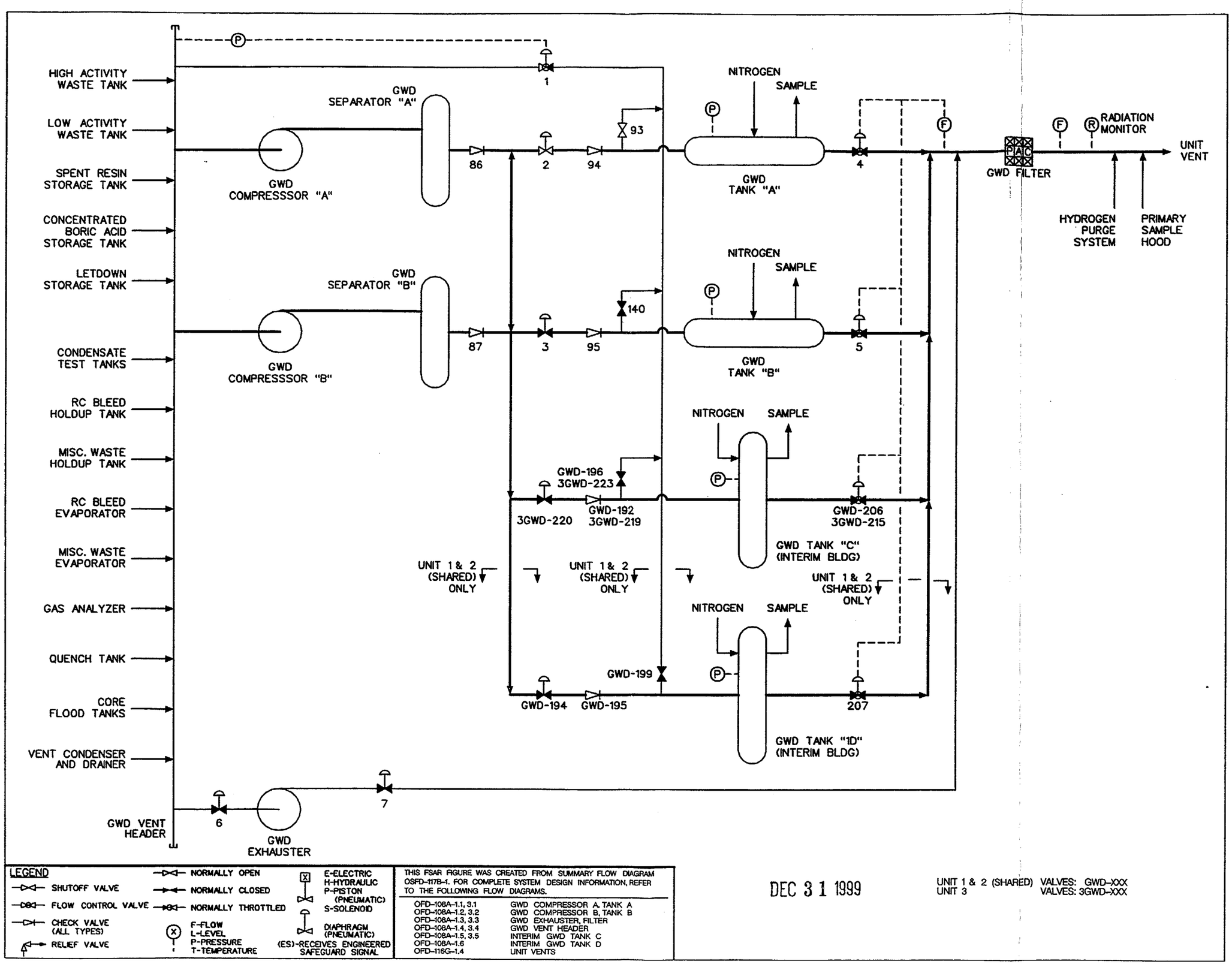
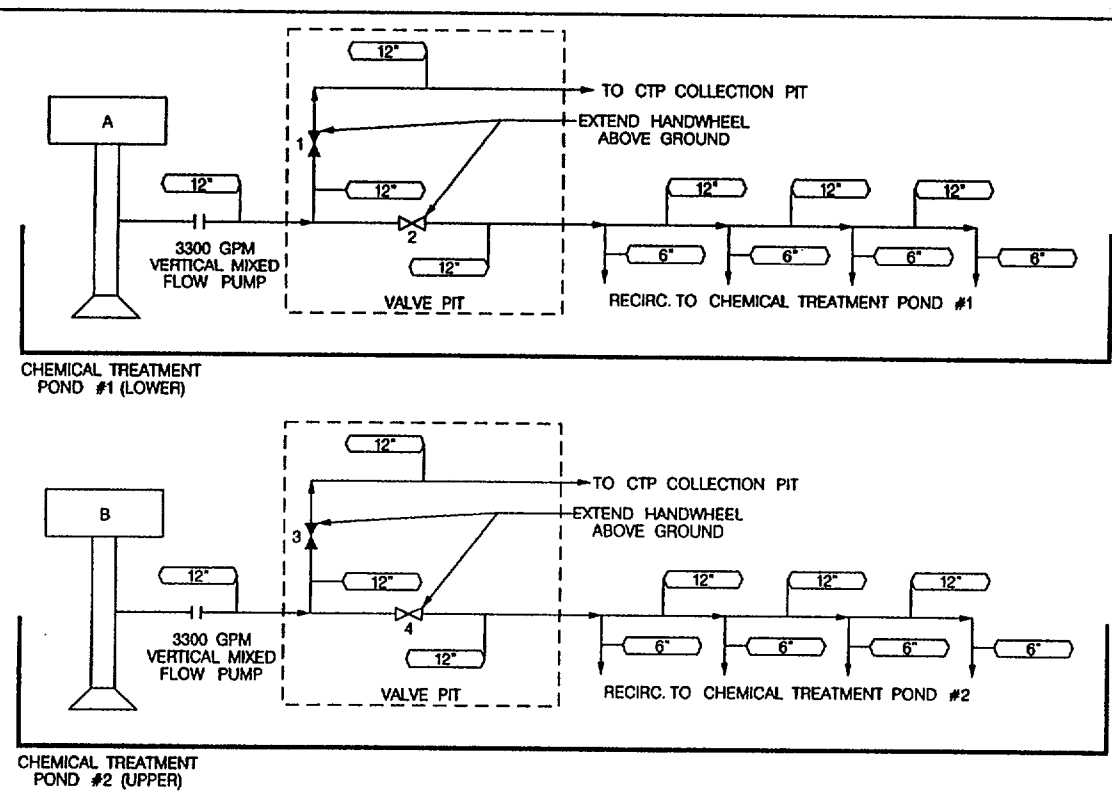


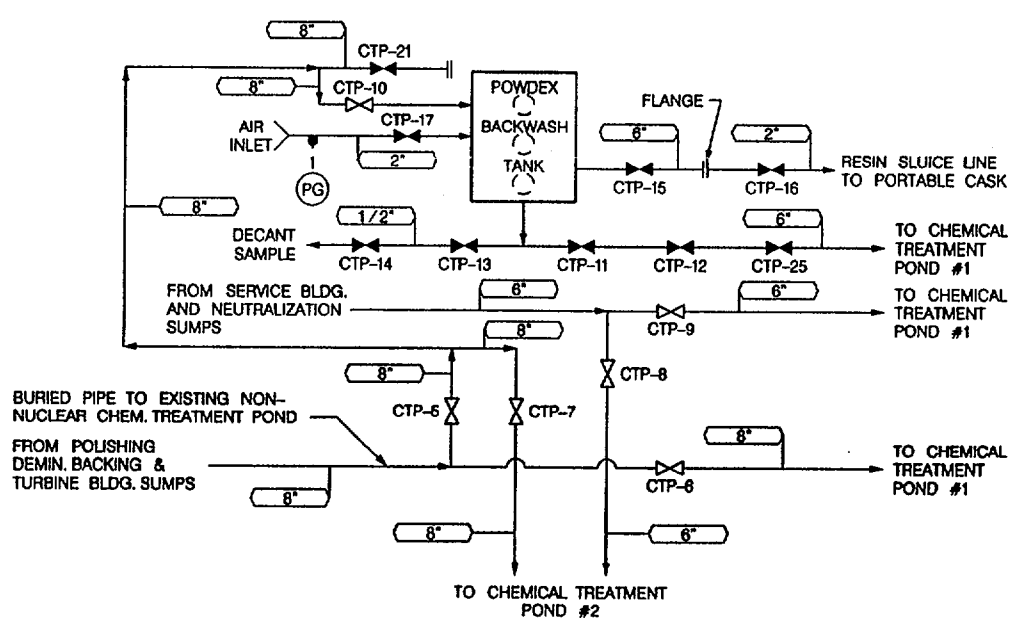
Figure 11-3
Gaseous Waste Disposal System



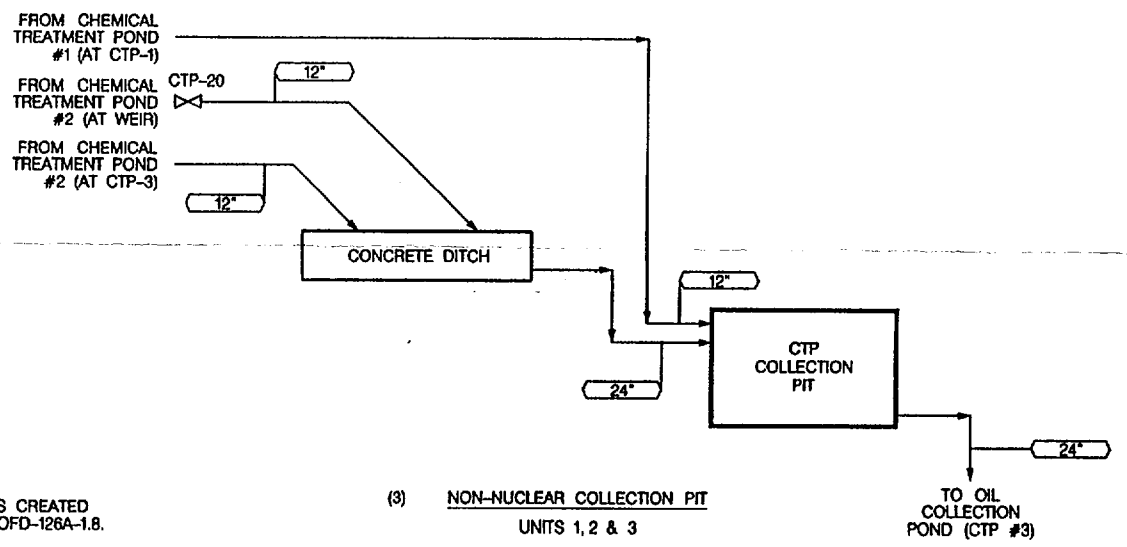
NOTES:

1. TWO SYSTEMS REQUIRED WITH 7'-0" LONG PUMP INSTALLED IN NEW POND, AND 2'-0" LONG PUMP INSTALLED IN EXISTING POND.
2. PUMP TO BE LOCATED IN DEEP END OF POND WITH FOUR (4) 6" PIPE OUTLETS EQUALLY SPACED AT FAR END OF POND.

(1) NON-NUCLEAR CHEMICAL TREATMENT POND MIXING SYSTEM
UNITS 1, 2 & 3



(2) NON-NUCLEAR CHEMICAL TREATMENT POND
UNITS 1, 2 & 3



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THIS FSAR FIGURE WAS CREATED FROM FLOW DIAGRAM OFD-126A-1.8.

(3) NON-NUCLEAR COLLECTION PIT
UNITS 1, 2 & 3

Figure 11-4
Waste Water Collection Basin