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SOUTHERN COMPANY
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10 CFR 50.90

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

Ladies and Gentlemen:

In accordance with the provisions of 10 CFR 50.90, Southern Nuclear Operating Company (SNC) proposes to amend the Farley Nuclear Plant (FNP) Unit 1 and Unit 2 Technical Specifications (TS), Appendix A to Operating Licenses NPF-2 and NPF-8. This Technical Specifications amendment request addresses the required Technical Specifications changes associated with the replacement of the current Westinghouse Model 51 steam generators with the Westinghouse Model 54F. The proposed Technical Specifications changes include revisions to steam generator level setpoints, RCS operational leakage and specific activity limits, and the steam generator tube inspection program. The specific changes are summarized in Attachment 1.

To support replacement of the Farley Nuclear Plant Westinghouse Model 51 steam generators with a Westinghouse Model 54F, SNC has completed a comprehensive program to reanalyze or evaluate LOCA, non-LOCA, thermal hydraulic and nuclear safety aspects of the NSSS and Balance of Plant (BOP) structures, systems and components. Major NSSS and BOP components, systems and sub-systems have been assessed with respect to bounding conditions expected for operation with the new steam generators. Reactor Trip System (RTS) and ESF Actuation System (ESFAS) setpoints and allowable values have been assessed, and the proposed steam generator level setpoint changes, in conjunction with existing RTS and ESFAS setpoints, will provide adequate protection for all design basis events. NSSS control systems have been evaluated for operation with the new steam generators installed, and acceptable results were obtained.

The steam generator replacement analyses and evaluations were performed in accordance with the current FNP licensing bases. For selected analyses or evaluations, the specific analytical technique used is referenced or discussed in the attached NSSS and BOP licensing reports. The analyses demonstrate that all acceptance criteria, including DNB, RCS pressure, LOCA peak cladding temperature, containment pressure and temperature, and dose limits continue to be met.

Attachment 1 provides a technical basis summary and a list of the proposed changes to the Technical Specifications and associated Bases. Attachment 2 provides the revised Technical Specifications pages. Attachment 3 provides the significant hazards consideration in accordance with the requirements of 10 CFR 50.92. The technical basis for the proposed changes is provided by Attachment 4, the NSSS Licensing Report, and Attachment 5, the BOP Licensing Report. Attachment 5 also includes an environmental impact evaluation.

Appendix C of FNP Unit 1 (Unit 2) Facility Operating License (FOL), titled Additional Conditions Operating License No. NPF-2 (NPF-8), includes the following Additional Condition: "SNC shall provide a Steam Generator (SG) Tube Rupture radiological consequences analysis that incorporates flashing fraction, which is appropriate for the Unit 1 (Unit 2) design," with a Condition Completion Date of: "Prior to the Unit 1 (2) steam generator replacement outage in spring 2000 (2001)." SNC has met this Additional Condition for each FNP FOL by providing the required information in this submittal. The analysis is provided in the NSSS Licensing Report (Attachment 4) and the BOP Licensing Report (Attachment 5).

It is noted that the proposed Technical Specifications changes (mark-up and typed pages) are based on the Improved Technical Specifications (ITS) format as submitted in the SNC to NRC letter dated April 24, 1998, FNP Technical Specifications Changes, Conversion to the Improved Technical Specifications – Clean-Typed Copy. Two sets of mark-ups are provided. The set under the tab for Unit 1 reflects the Technical Specifications pages for the period of time between the replacement of Unit 1 steam generators in spring 2000 and before replacement of Unit 2 steam generators in spring 2001. The set under the tab for Unit 2 reflects the Technical Specifications pages after both Unit 1 and Unit 2 steam generators have been replaced.

SNC has determined that the proposed changes will not significantly increase the amount of any effluent which may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The proposed license amendments will not significantly affect the quality of the human environment. A copy of the proposed changes has been sent to the Alabama State Designee, in accordance with 10 CFR 50.91(b)(1). Southern Nuclear Operating Company requests NRC approval of the proposed licensing changes by January 4, 2000. The Unit 1 amendment should become effective prior to entering Mode 5 following refueling for Cycle 17 (spring 2000), and the Unit 2 amendment should become effective prior to entering Mode 5 following refueling for Cycle 15 (spring 2001).

Mr. D. N. Morey states that he is a Vice President of Southern Nuclear Operating Company and is authorized to execute this oath on behalf of Southern Nuclear Operating Company and that, to the best of his knowledge and belief, the facts set forth in this letter and attachments are true.

If you have any questions, please advise.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

Dave Morey

Sworn to and subscribed before me this 1st day of December 1998.

Martha Gayle Dow
Notary Public

My Commission Expires: November 1, 2001

DNM/CHM

Attachments:

1. Basis for Proposed Changes
2. Technical Specifications Changed Pages
3. Significant Hazards Evaluation
4. NSSS Licensing Report
5. BOP Licensing Report

cc: Mr. L. A. Reyes, Region II Administrator
Mr. J. I. Zimmerman, NRR Project Manager
Mr. T. P. Johnson, Plant Sr. Resident Inspector
Dr. D. E. Williamson, State Department of Public Health

Attachment 1

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

Basis for Proposed Changes

Basis for Proposed Changes

The proposed Technical Specifications changes are summarized in the attached table. The proposed changes are based on analyses and detailed evaluations which support the replacement of the current Westinghouse Model 51 steam generators (SG) with a Westinghouse Model 54F.

To support replacement of the Farley Nuclear Plant (FNP) Westinghouse Model 51 SG with a Westinghouse Model 54F, SNC has completed a comprehensive program to re-analyze or evaluate LOCA, non-LOCA, thermal hydraulic and nuclear safety aspects of the NSSS and Balance of Plant (BOP) structures, systems and components. Major NSSS components (*e.g.*, reactor vessel, pressurizer, RCPs, new steam generators) and BOP components (*e.g.*, turbine, generator, MSIVs, condensate and feedwater pumps), and major systems and sub-systems (*e.g.*, safety injection, auxiliary feedwater, RHR, electrical distribution system, emergency diesel generators, containment cooling, auxiliary cooling water, ultimate heat sink) have been assessed with respect to bounding conditions expected for operation with the new SGs. Reactor trip and ESF actuation setpoints and allowable values have been assessed, and the proposed changes will provide adequate protection for all design basis events. Control systems (*e.g.*, rod control, pressurizer pressure and level, turbine overspeed, steam generator level, steam dumps) have been evaluated for operation with new SGs installed and acceptable results were obtained.

The steam generator replacement analytical techniques (methodology and tools) and engineering efforts were performed in accordance with the licensing bases that currently exist for FNP. The Westinghouse BELOCA methodology was used to analyze the effects of the Model 54F SG. This analysis demonstrates that FNP continues to meet the criteria of 10 CFR 50.46 for LBLOCA. Where applicable, iodine spiking was considered in radiological assessments as described in NUREG-0800. For other selected analyses or evaluations, the specific analytical techniques used for SG replacement are referenced or discussed in the NSSS and BOP licensing reports.

The changes in trip setpoints have resulted from new SG design differences and analyses performed to support operation with the new SGs. The associated allowable values were modified to be consistent with the setpoint changes. The results of the analysis and FNP specific setpoint calculations conclude that since all acceptance criteria continue to be met, the proposed setpoint values are acceptable.

The RCS Operational Leakage criteria for SGs on Unit 1 are adjusted to match the current limits approved for Unit 2 of 150 gpd from any one SG and 450 gpd from all SGs. These limits agree with the current guidance of EPRI and NEI for leakage. The RCS Specific Activity limit was adjusted from 0.15 to 0.5 μCi/gm. All radiological analyses were performed using a value of 1.0 μCi/gm RCS Specific Activity and 1 gpm (1440 gpd) RCS Operational Leakage for SGs, thus bounding the proposed Technical Specifications limits. The calculated offsite doses continue to meet the acceptance criteria of NUREG-0800.

The SG Tube Surveillance Program and Tube Inspection Report requirements of the Technical Specifications are revised to remove the reference to sleeving, Alternate Repair Criteria and F* SG tube plugging criteria. These options are not applicable to the new Model 54F SG since a new tube material is being used. Tube plugging will be the method to correct a SG tube defective condition in the Model 54F.

In the SG Tube Surveillance Program acceptance criteria for Preservice Inspection, the unnecessary restriction that the preservice inspection be performed after the field hydrostatic pressure test and prior to power operation is being removed. The proposed change affects only the schedule for performing the preservice inspection of tubing in the replacement SGs by removing the restriction that the preservice inspection be performed only after the field hydrostatic pressure test. This proposed change is in compliance with the requirements of Regulatory Guide 1.83, Revision 1, and Section XI of the ASME Boiler and Pressure Vessel Code. The proposed change continues to ensure that preservice inspection of replacement SG tubes will be performed to establish the baseline condition of SG tubing. Also, the inspection, as required, will still be performed prior to the resumption of service following the SG replacement and thus ensure that subsequent inservice inspections will provide evidence of structural degradation of SG tubes.

In addition, the proposed schedule change does not reduce the effectiveness of the eddy current baseline inspection. The shop-performed eddy current examinations will be performed after the required ASME Section III hydrostatic pressure test. The hydrotest will be conducted at a test pressure of 1.25 times the design pressure. Subsequent to installation of the replacement SG, system hydrostatic pressure tests must be performed in accordance with ASME Section XI. These test pressures are substantially less than the Section III hydrotest and will not affect the results of the preservice baseline eddy current examinations. Finally, the proposed change, as discussed above, is similar to and consistent with the baseline inspection philosophy already approved by the NRC for other operating nuclear power plants. This exact change was approved by the NRC for North Anna Units 1 and 2 in a Safety Evaluation dated December 4, 1991.

The minimum SG water level required for SG operability during Modes 3, 4 and 5 is adjusted from 74 % to 75 % WRS based on the new SGs and the Farley specific uncertainty calculation. This change maintains the current margin necessary to ensure an adequate heat sink.

The Containment Leakage Testing Program and Containment Systems Bases are revised to reflect the change in the LOCA analyses peak calculated containment internal pressure for LOCA (P_a) from 43 to 43.8 psig. The Bases are also revised to reflect the decrease in the MSLB analyses peak calculated containment internal pressure from 52.4 to 52.0 psig. The LOCA and MSLB mass and energy release results remain bounded by the containment design pressure of 54 psig.

The Containment System Bases revision also reflects the decrease in the MSLB analyses peak calculated containment internal temperature from 383 to 367°F. The analyses resultant composite pressure and temperature profiles are sufficiently bounded by the existing EQ qualified report requirements

It is noted that the proposed Technical Specifications changes (mark-up and typed pages) are based on the improved TS format as submitted in the SNC to NRC letter dated April 24, 1998, FNP Technical Specifications Changes, Conversion to the Improved Technical Specifications - Clean-Typed Copy.

Additional minor editorial, typographical and format changes to the Bases and Programs sections are identified in the Technical Specifications, Bases and Programs sections mark-ups.

FNP Units 1 and 2
Summary of Technical Specifications Changes for Steam Generator Replacement

ITS Section	Description	Justification
Table 3.3.1-1 Table 3.3.2-1	SG Low-Low Level Trip Setpoint from 25% to 28% NR and its Allowable value from 24.6% to 27.6% NR. SG High-High (P-14) Trip Setpoint from 78.5% to 82% NR and its Allowable value changed from 78.9% to 82.4% NR.	The change in setpoints resulted from analytical values associated with replacement SG design differences and new analyses. The allowable value changes complement the setpoint changes. The setpoint calculations are based on FNP specific instrumentation uncertainty allowances. These changes provide acceptable results for all effected transients and accidents as described in WCAP 15098.
3.4.13 B 3.4.13	Set RCS Operational Leakage for SGs at 150 gpd from any one SG and 450 gpd from all SGs. (Unit 1 only)	The leakage limits are adjusted to match the current limits approved for Unit 2. These limits agree with the current guidance of EPRI and NEI and ensure integrity of the SG tubing. In addition, these leak rates are bounded by conservative analyses assumptions.
3.4.16 Fig. 3.4.16-1 B 3.4.16 B 3.7.16	Change RCS Specific Activity DEI from 0.15 to 0.5 μCi/gm.	Radiological analysis performed for RSG used a value of 1.0 μCi/gm, and the accident analyses results (doses) demonstrate doses do not exceed the limits.
5.5.9	The SG Tube Surveillance Program inspectance criteria for Preservice Inspection is revised to remove the unnecessary restriction that the preservice inspection be performed after the field hydrostatic pressure test and prior to power operation.	The proposed change is similar to and consistent with the baseline inspection philosophy already approved by the NRC for other operating nuclear power plants. The scheduler change will afford required preservice test, i.e., hydrostatic testing and tube inspections.
5.5.9 5.6.10	Change the SG Tube Surveillance Program and the SG Tube Inspection Report to remove reference to sleeving, Alternate Repair Criteria, and F*. (F* is a Unit 2 only change)	The existing options for sleeving and Alternate Repair Criteria are not applicable to the new Model 54F SG; i.e., since a new tube material is being used, the current technical basis is no longer applicable.

FNP Units 1 and 2
Summary of Technical Specifications Changes for Steam Generator Replacement

ITS Section	Description	Justification
3.4.5 B 3.4.5 3.4.6 B 3.4.6 3.4.7 B 3.4.7	Change the minimum SG water level for SG Operability during Modes 3, 4 and 5 from 74% to 75% WR.	The change in TS criterion for minimum indicated WR level resulted from analytical values and analysis associated with steam generator replacement design differences. This value provides the current margin necessary to ensure an adequate heat sink, i.e., tubes are covered. The criterion includes FNP specific instrument uncertainties.
B 3.6.1 B 3.6.2 B 3.6.4 B 3.6.5 B 3.6.6 5.5.17	Revise peak calculated containment internal pressure for LOCA (P_a) from 43 psig to 43.8 psig. Revise peak calculated containment internal pressure and temperature for a MSLB from 52.4 to 52.0 psig and 383 to 376°F.	The revised P_a acceptance criterion referenced in the Containment Leakage Test Program and Bases reflects the results of new containment analysis performed for steam generator replacement. The analysis results show that containment design limits are not exceeded. The peak pressure and temperature MSLB analyses results do not exceed containment design limits. Composite LOCA and MSLB results do not invalidate EQ of safety-related electrical equipment.

Attachment 2

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

Technical Specifications Changed Pages

Technical Specifications Pages for Unit 1 Replacement – Changed Pages List

Technical Specifications Pages for Unit 1 Replacement – Marked-up Pages

Technical Specifications Pages for Unit 1 Replacement – Typed Pages

Technical Specifications Pages for Unit 2 Replacement – Changed Pages List

Technical Specifications Pages for Unit 2 Replacement – Marked-up Pages

Technical Specifications Pages for Unit 2 Replacement – Typed Pages

Unit 1

Changed Pages List

The pages provided in this section will be issued prior to Unit 1 entering MODE 5 for Cycle 17 (Spring 2000).

Pages noted with an '*' have changed only due to information rolling over from one page to another.

Page	Revision	Page		Revision	Page	Revision
3.3.1-17	Replace	B 3.4.13-3	*	Replace	5.5-5	Replace
3.3.2-11	Replace	B 3.4.13-4	*	Replace	5.5-6	Replace
3.4.5-3	Replace	3.4.16-1		Replace	5.5-7	Replace
B 3.4.5-5	Replace	3.4.16-2		Replace	5.5-8	Replace
B 3.4.5-6	Replace	3.4.16-4		Replace	5.5-9	Replace
3.4.6-2	Replace	B 3.4.16-1		Replace	5.5-10	Replace
B 3.4.6-5	Replace	B 3.4.16-2		Replace	5.5-11	Replace
3.4.7-1	Replace	B 3.4.16-3		Replace	5.5-12	Replace
3.4.7-2	Replace	B 3.6.1-2		Replace	5.5-13	Replace
B 3.4.7-1	Replace	B 3.6.2-2		Replace	5.5-15	Replace
B 3.4.7-2	Replace	B 3.6.4-1		Replace	5.5-17	Replace
B 3.4.7-4	Replace	B 3.6.5-2		Replace	5.5-18	Replace
B 3.4.7-5	Replace	B 3.6.5-3	*	Replace	5.5-24	Replace
3.4.13-1	Replace	B 3.6.6-3		Replace	5.6-5	Replace
B 3.4.13-2	Replace	B 3.7.16-1		Replace	5.6-6	Replace

Table 3.3.1-1 (page 4 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
11.	Reactor Coolant Pump (RCP) Breaker Position						
	a. Single Loop	1(g)	1 per RCP	N	SR 3.3.1.12	NA	NA
	b. Two Loops	1(h)	1 per RCP	M	SR 3.3.1.12	NA	NA
12.	Undervoltage RCPs	1(f)	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 2640 V	≥ 2680 V
13.	Underfrequency RCPs	1(f)	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 56.9 Hz	≥ 57 Hz
14.	Steam Generator (SG) Water Level — Low Low	1,2	3 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.14	~~≥ 24.6%~~ ≥ 27.6% (k) ≥ 24.6% (l)	~~≥ 25%~~ ≥ 28% (k) ≥ 25% (l)

(f) Above the P-7 (Low Power Reactor Trips Block) interlock.

(g) Above the P-8 (Power Range Neutron Flux) interlock.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(k) **Unit 1 only (after Steam Generator Replacement)**

(l) **Unit 2 only (before Steam Generator Replacement)**

Table 3.3.2-1 (page 4 of 4)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
5.	Turbine Trip and Feedwater Isolation						
	a. Automatic Actuation Logic and Actuation Relays	1,2(g)	2 trains	H	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
	b. SG Water Level - High High (P-14)	1,2(g)	3 per SG	I	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	~~≤ 78.9%~~ ≤ 82.4% (h) ≤ 78.9% (i)	~~≤ 78.5%~~ ≤ 82% (h) ≤ 78.5% (i)
	c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6.	Auxiliary Feedwater						
	a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
	b. SG Water Level - Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	~~≥ 24.6%~~ ≥ 27.6% (h) ≥ 24.6% (i)	~~≥ 25%~~ ≥ 28% (h) ≥ 25% (i)
	c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
	d. Undervoltage Reactor Coolant Pump	1,2	2 per bus	I	SR 3.3.2.5 SR 3.3.2.7	≥ 2640 volts	≥ 2680 volts
	e. Trip of all Main Feedwater Pumps	1	2 per pump	J	SR 3.3.2.10	NA	NA
7	ESFAS Interlocks						
	a. Reactor Trip, P-4	1,2,3	1 per train, 2 trains	F	SR 3.3.2.6	NA	NA
	b. Pressurizer Pressure, P-11	1,2,3	3	K	SR 3.3.2.7	≤ 2003 psig	≤ 2000 psig
	c. T_{avg} - Low Low, P-12 (Decreasing) (Increasing)	1,2,3	1 per loop	K	SR 3.3.2.7	≥ 542.6°F ≤ 545.4°F	≥ 543°F ≤ 545°F

(g) Except when all Main Feedwater lines are isolated by either a Main Feedwater Stop Valve or an MFRV and associated bypass valve or by a closed manual valve.

(h) **Unit 1 only (after Steam Generator Replacement)**
(i) **Unit 2 only (before Steam Generator Replacement)**

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.2	Verify steam generator secondary side water levels are ~~≥ 74%~~ (wide range) for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

≥ [Unit 1 only: 75 %] [Unit 2 only: 74 %]

ACTIONS

C.1 and C.2 (continued)

inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened.

The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ~~≥ 74%~~ for required RCS loops. If the SG

≥ [Unit 1 only: 75 %] [Unit 2 only: 74 %]

(continued)

[Unit 1 only: 75 %] [Unit 2 only: 74 %]

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

Rollover to Page B 3.4.5-5

secondary side wide range water level is < ~~74~~%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES

None.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required RHR loop inoperable. AND Two required RCS loops inoperable.	B.1	Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	C.2	Initiate action to restore one loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water levels are ~~≥ 74%~~ e (wide range) for required RCS loops.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

≥ [Unit 1 only: 75 %] [Unit 2 only: 74 %]

[Unit 1 only: 75 %] [Unit 2 only: 74 %]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ≥ ~~74%~~. If the SG secondary side wide range water level is < ~~74%~~, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops — MODE 5, Loops Filled

≥ [**Unit 1 only: 75 %**] [**Unit 2 only: 74 %**]

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be ≥ 74% (wide range).

---NOTES---

1. The RHR pump of the loop in operation may not be in operation for ≤ 2 hours per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ 325°F unless:

   a. The secondary side water temperature of each SG is < 50°F above each of the RCS cold leg temperatures; or

   b. The pressurizer water volume is less than 770 cubic feet (24% of wide range, cold, pressurizer level indication).

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

5. The number of operating Reactor Coolant Pumps is limited to one at RCS temperatures < 110°F with the exception that a second pump may be started for the purpose of maintaining continuous flow while taking the operating pump out of service.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side water levels not within limits.	A.1	Initiate action to restore a second RHR loop to OPERABLE status.	Immediately
	OR		
	A.2	Initiate action to restore required SG secondary side water levels to within limits.	Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side water level is ~~≥ 74%~~ (wide range) in required SGs.	12 hours

≥ [Unit 1 only: 75 %] [Unit 2 only: 74 %]

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation (Ref. 1) are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels ~~above 74~~% (wide range) to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

≥ [Unit 1 only: 75 %] [Unit 2 only: 74 %]

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops — MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ~~≥ 74%~~ (wide range). One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ~~≥ 74%~~ (wide range). Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to not be in operation ≤ 2 hours per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 2 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration

(continued)

BASES

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ ~~74%~~ (wide range).

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels < ~~74%~~ (wide range), redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

[Unit 1 only: 73 %] [Unit 2 only: 74 %]

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal.

The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side wide range water levels are ≥ 74% ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥ 74% (wide range) in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE;

d. ~~420 gallons per day for Unit 1 and~~ 450 gallons per day ~~for Unit 2~~ total primary to secondary LEAKAGE through all steam generators (SGs); and

e. ~~140 gallons per day for Unit 1 and~~ 150 gallons per day ~~for Unit 2~~ primary to secondary LEAKAGE through any one SG.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1	Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists.	B.1 AND B.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours

BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is typically seen as a precursor to a LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 150 gpd per SG primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The FSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via the main steam safety valves. The majority of the activity released to the atmosphere results from the tube rupture. Therefore, the 150 gpd per SG primary to secondary LEAKAGE is inconsequential.

Insert 1 →

The main steam line break (MSLB) is more limiting for site radiation releases. The MSLB analysis in support of Generic Letter 95-05 has shown that steam generator tube leakage of 23.8 gpm in the faulted loop, and 0.1 gpm (approximately 150 gpd) in each of the intact loops (total leakage of 24 gpm), following a main steam line break outside of containment, but upstream of the main steam isolation valves, results in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines. The RCS specific activity assumed was 0.15 microCi/gm Dose Equivalent I-131, with either a pre-existing or an accident initiated iodine spike.

The RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS operational LEAKAGE shall be limited to:

a. <u>Pressure Boundary LEAKAGE</u>

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher

(continued)

Insert 1 for ITS page B 3.4.13-2

[Unit 1 Only] The SLB is more limiting for primary to secondary LEAKAGE. The safety analysis for the SLB assumes 500 gpd and 470 gpd primary to secondary LEAKAGE in the ruptured and intact steam generators respectively as an initial condition. The dose consequences resulting from the SLB accident are bounded by a small fraction (i.e., 10%) of the limits defined in 10 CFR 100. The RCS specific activity assumed was a bounding value of 1.0 μCi/gm DOSE EQUIVALENT I-131, with either a pre-existing or an accident initiated iodine spike. These values bound the Technical Specifications values.

[Unit 2 Only] The SLB is more limiting for primary to secondary LEAKAGE. The safety analysis for the SLB assumes 500 gpd primary to secondary LEAKAGE in one steam generator as an initial condition. The Unit 2 MSLB analysis in support of Generic Letter 95-05 has shown that steam generator tube leakage of 23.8 gpm in the faulted loop, and 0.1 gpm (approximately 150 gpd) in each of the intact loops (total leakage of 24 gpm), following an SLB outside of containment, but upstream of the main steam isolation valves, results in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines. The RCS specific activity assumed was 0.15 μCi/gm DOSE EQUIVALENT I-131, with either a pre-existing or an accident initiated iodine spike. These values bound the Technical Specifications values.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 ~~> 0.15 μCi/gm.~~ [Unit 1 Only: > 0.5 μCi/gm] [Unit 2 Only: > 0.15 μCi/gm]	-----Note----- LCO 3.0.4 is not applicable. ----- A.1 Verify DOSE EQUIVALENT I-131 within the acceptable region of Figure 3.4.16-1.	Once per 4 hours
	AND	
	A.2 Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit.	B.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 in the unacceptable region of Figure 3.4.16-1.	C.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity ≤ 100/Ē μCi/gm.	7 days
SR 3.4.16.2	-----NOTE----- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ~~≤ 0.15 μCi/gm.~~ e [Unit 1 Only: ≤ 0.5 μCi/gm] [Unit 2 Only: ≤ 0.15 μCi/gm]	14 days AND Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

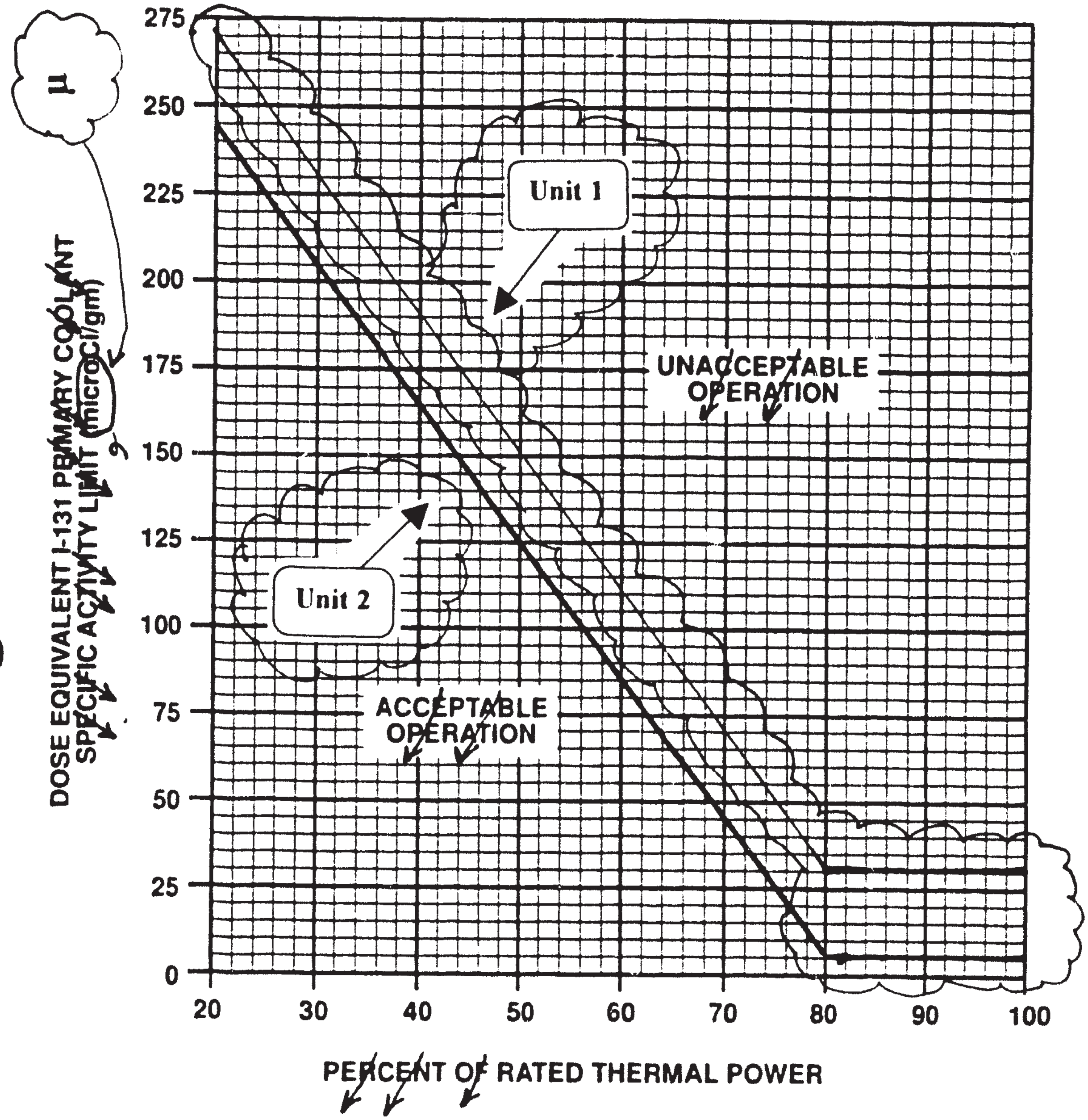

Figure 3.4.16-1 (page 1 of 1)
DOSE EQUIVALENT I-131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity > ~~0.15 μCi/gram Dose Equivalent I-131.~~

[Unit 1 only: 0.5 μCi/gm] [Unit 2 only: 0.15 μCi/gm] DOSE EQUIVALENT I-131

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident, or for the duration of the accident at the Low Population Zone, is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to an appropriate fraction of the 10 CFR 100 limits (i.e., a small fraction of or well within the 10 CFR 100 limits depending on the specific accident analysis) during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) or main steam line break (MSLB) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to an appropriate fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR or main steam line break (MSLB) accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting doses will not exceed an appropriate fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant ~~at the LCO limit~~ and ~~an existing~~ reactor coolant steam generator (SG) tube leakage ~~rate~~ of ~~150 gpd per SG~~. The ~~main steam line break (~~MSLB~~)~~ analysis assumes a steam generator tube

a bounding

at [Unit 1 only: 1.0 μCi/gm]
[Unit 2 only: 0.5 μCi/gm]

[Unit 1 only: 1 gpm total for three SGs]
[Unit 2 only: 150 gpd per SG]

(continued)

[Unit 2 only: 23.8 gpm]

[Unit 2 only: 150 gpd]

[Unit 1 only: 1440 gpd]
[Unit 2 only: 24 gpm]

for a

APPLICABLE SAFETY ANALYSES (continued)

leakage of ~~23.8 gpm~~ in the faulted loop and ~~0.1 gpm (approximately 150 gpd)~~ in each of the intact loops (total leakage of ~~24 gpm~~). This analysis resulted in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines using ~~Regulatory Guide 1.109~~ Dose Conversion Factors (DCFs). The initial RCS specific activity assumed was ~~0.15 micro-Ci/gm Dose Equivalent~~ I-131 with an iodine spike. The safety analysis assumes for both the SGTR and MSLB the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.16, "Secondary Specific Activity."

ICRP 30

¶

[Unit 1 only: 1.0 μCi/gm]
[Unit 2 only: 0.15 μCi/gm]
DOSE EQUIVALENT

These values bound the Technical Specifications values.

The analysis for the MSLB accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The SGTR analysis assumes an RCS coolant activity of ~~0.5 μCi/gm~~ DOSE EQUIVALENT I-131. The MSLB analysis considers two cases of reactor coolant specific activity. One case assumes specific activity at ~~0.15 μCi/gm~~ DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the I-131 activity release rate into the reactor coolant by a factor of 500 immediately after the accident. The second case assumes the initial reactor coolant iodine activity at ~~9.0 μCi/gm~~ DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of 100/Ē μCi/gm for gross specific activity.

[Unit 1 only: 1.0 μCi/gm]
[Unit 2 only: 0.15 μCi/gm]

[Unit 1 only: 1.0 μCi/gm]
[Unit 2 only: 0.5 μCi/gm]

[Unit 1 only: 60 μCi/gm]
[Unit 2 only: 9 μCi/gm]

These values bound the Technical Specifications values.

The SGTR analysis also assumes a loss of offsite power coincident with a reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

The main steam line break (MSLB) analysis assumes a double-ended guillotine break of a main steamline outside of containment. The affected steam generator will rapidly depressurize and release both the radionuclides initially contained in the secondary coolant, and the primary coolant activity transferred via SG tube leakage, directly to

(continued)

[Unit 1 only: 60.0 μCi/gm] [Unit 2 only: 9.0 μCi/gm]

BASES

APPLICABLE SAFETY ANALYSES (continued)

the outside atmosphere. A portion of the iodine activity initially contained in the intact SGs and noble gas activity due to SG tube leakage is released to the atmosphere through either the SG atmospheric relief valves (ARVs) or the SG safety relief valves.

The safety analysis assumes an accident initiated iodine spike and shows the radiological consequences of a MSLB accident are within a small fraction of the Reference 1 dose guideline limits.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1, in the applicable specification, for more than 48 hours. The MSLB safety analysis has concurrent and pre-accident iodine spiking levels up to ~~9.0 μCi/gm~~ DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a MSLB accident occurring during the established 48 hour time limit. The occurrence of a MSLB accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

The limits on RCS specific activity are also used for establishing standardization in plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement.

[Unit 1 only: 0.5 μCi/gm] [Unit 2 only: 0.15 μCi/gm]

LCO

The specific iodine activity is limited to 0.5 μCi/gm DOSE EQUIVALENT I-131 for the SGTR analysis and ~~0.15 μCi/gm~~ DOSE EQUIVALENT I-131 for the MSLB analysis, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the thyroid dose to an individual during the Design Basis Accident (DBA) will be an appropriate fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose.

(continued)

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed; and

d. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day for the first 24 hours and 0.075% thereafter (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from a LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.15% per day in the safety analysis at P_a = ~~43 psig~~ (Ref. 3).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of the NRC Policy Statement.

[Unit 1 only: 43.8 psig] [Unit 2 only: 43 psig]

BASES

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B, as the maximum allowable containment leakage rate at the calculated peak containment internal pressure, P_a = ~~(43 psig),~~ following a LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of the NRC Policy Statement.

[Unit 1 only: 43.8 psig] [Unit 2 only: 43 psig]

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. The worst case SLB generates larger mass and energy release than the worst case LOCA. Thus, the SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

[Unit 1 only: 52.0 psig]
[Unit 2 only: 52.4 psig]

The initial pressure condition used in the containment analysis was 17.7 psia (3.0 psig). This resulted in a maximum peak pressure from a SLB of ~~52.4 psig~~. The containment analysis (Ref. 1) shows the maximum peak calculated containment pressure, P_a, resulting from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA, ~~43.0 psig~~, does not exceed the containment design pressure, 54 psig.

The containment was also designed for an external pressure load equivalent to −3.0 psig. The inadvertent actuation of the Containment

[Unit 1 only: 43.8 psig] [Unit 2 only: 43 psig]

(continued)

[Unit 1 only: 367°F] [Unit 2 only: 383°F]

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 127°F. This resulted in a maximum containment air temperature of ~~383°F~~. The design air temperature is 378°F.

Insert 2

[Unit 2 only]

The temperature limit is used to establish the environmental qualification operating envelope for containment. The maximum peak containment air temperature was calculated to exceed the containment design air temperature for only a few seconds during the transient. The basis of the containment design air temperature, however, is to ensure the performance of safety-related equipment inside containment (Ref. 2). Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design air temperature was short enough that the equipment surface temperatures remained below the equipment design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System.

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a SLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of the NRC Policy Statement.

Insert 2 for ITS page B 3.6.5-2

[Unit 1 only] The temperature limit is used to establish the environmental qualification operating envelope for containment. The basis of the containment design air temperature is to ensure the performance of safety-related equipment inside containment (Ref. 2). Thermal analyses show that the containment air temperature remains below the equipment design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

BACKGROUND

Containment Cooling System (continued)

ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, unless an LOSP signal is present, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If an LOSP signal is present, only the two fans selected (one per train) will receive an auto-start signal and will start in slow speed. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. In addition, if temperature at the cooler discharge reaches 135°F, fusible links holding dropout plates will open and the fan discharge will no longer be directed through the common discharge header. This function helps to protect the fans in a post-accident environment by reducing the back pressure on the fans. The temperature of the SW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

[Unit 1 only: 52.0 psig]
[Unit 2 only: 52.4 psig]

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is ~~52.4 psig~~ (experienced during an SLB). The analysis shows that the peak containment temperature is ~~383°F~~ (experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.)

[Unit 1 only: 367°F] [Unit 2 only: 383°F]

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.16 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a ~~420 (Unit 1) or~~ 450 ~~(Unit 2)~~ gallons per day tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of ~~0.15 μCi/gm~~ [Unit 1 only: 0.5 μCi/gm] [Unit 2 only: 0.15 μCi/gm] (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours).

With the specified activity limit, the resultant 2 hour thyroid dose to a person at the site boundary would be within the limits of 10 CFR 20.1-20.601 if the main steam safety valves (MSSVs) and Atmospheric Relief Valves (ARVs) are open for 2 hours following a trip from full power.

Operating at the allowable limits results in a 2 hour site boundary exposure well within the 10 CFR 100 (Ref. 1) limits.

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological

(continued)

5.5.8 Inservice Testing Program (continued)

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.9 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies.

5.5.9.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

[Specification 5.5.9 is not required to be performed on the replacement steam generators during the shutdown when the steam generators are replaced.]

(continued)

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.9.1 Steam Generator Sample Selection and Inspec[illegible]on

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.9-1.

5.5.9.2 Steam Generator Tube* Sample Selection and Inspection

5.5.9.2.1.a

5.5.9.2.1.c

5.5.9.2.1 The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Tables 5.5.9-2 and 5.5.9-3. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.9.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.9.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. [~~(For~~ Unit 2 only: Selection of tubes to be inspected is not affected by the F* designation. ~~)~~ When applying the exceptions of ~~5.5.9.2.a~~ a through ~~5.5.9.2.e~~ c, previous defects or imperfections in the area repaired by sleeving are not considered an area requiring reinspection.] The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

[Unit 2 only]

* When referring to a steam generator tube, the sleeve shall be considered a part of the tube if the tube has been repaired per Specification 5.5.9.4.a.9.

(continued)

5.5.9.2.1 (continued)

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 5.5.9.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube ~~or sleeve inspection~~, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

[Unit 2 only: or sleeve inspection]

[Unit 2 only]

4. Indications left in service as a result of application of the tube support plate voltage-based repair criteria shall be inspected by bobbin coil probe during all future refueling outages.

c. The tubes selected as the second and third samples (if required by Tables 5.5.9-2 and 5.5.9-3) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

(continued)

5.5.9.2.1 (continued)

[Unit 2 only]

d. Implementation of the steam generator tube/tube support plate repair criteria requires a 100 percent bobbin coil inspection for hot-leg and cold-leg tube support plate intersections down to the lowest cold-leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes or sleeves must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

(continued)

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.9.2.2 ~~(For Unit 2 only)~~ Steam Generator F* Tube Inspection

[Unit 2 only]

In addition to the minimum sample size as determined by Specification 5.5.9.2.1, all F* tubes will be inspected within the tubesheet region. The results of this inspection will not be a cause for additional inspections per Tables 5.5.9-2 and 5.5.9-3.

5.5.9.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Tables 5.5.9-2 and 5.5.9-3 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.9.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Tables 5.5.9-2 and 5.5.9-3 during the shutdown subsequent to any of the following conditions:

(continued)

5.5.9.3 Inspection Frequencies (continued)

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.13.

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

5.5.9.4 Acceptance Criteria

[Unit 2 only: or sleeve]

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube ~~or sleeve~~ from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

[Unit 2 only: or sleeve]

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube ~~or sleeve~~.

[Unit 2 only: including the sleeve if the tube has been repaired]

3. Degraded Tube means a tube, ~~including the sleeve if the tube has been repaired~~, that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

[Unit 2 only: or sleeve]

4. % Degradation means the percentage of the tube ~~or sleeve~~ wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging ~~or repair limit~~. A tube ~~or sleeve~~ containing a defect is defective.

[Unit 2 only: or repair limit]

[Unit 2 only: or sleeve]

(continued)

5.5.9.4 Acceptance Criteria (continued)

[Unit 2 only]

6. Plugging or Repair Limit means the imperfection depth at or beyond which the tube shall be repaired (i.e., sleeved) or removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness. ~~(For Unit 2 only:~~ This definition does not apply for tubes that meet the F* criteria.~~)~~ For a tube that has been sleeved with a mechanical joint sleeve, through wall penetration of greater than or equal to 31% of sleeve nominal wall thickness in the sleeve requires the tube to be removed from service by plugging. For a tube that has been sleeved with a welded joint sleeve, through wall penetration greater than or equal to 24% of sleeve nominal wall thickness in the sleeve between the weld joints requires the tube to be removed from service by plugging. This definition does not apply to tube support plate intersections for which the voltage-based repair criteria are being applied. Refer to 5.5.9.4.a.14 for the repair limit applicable to these intersections. ~~(For Unit 2 only:~~ For a tube with an imperfection or flaw in the tube sheet below the lower joint for an installed elevated laser welded sleeve, no repair or plugging is required provided the installed sleeve meets all sleeved tube inspection requirements.~~)~~

[Unit 1 Only] <u>Plugging Limit</u> means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness.

[Unit 2 only: or sleeve]

7. Unserviceable describes the condition of a tube ~~or sleeve~~ if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.9.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg. [~~(For~~ Unit 2 only: For a tube with a tube sheet sleeve installed, the point of entry is the bottom of the tube sheet sleeve below the lower sleeve joint.~~)~~ For a tube that has been repaired by sleeving, the tube inspection should include the sleeved portion of the tube.]

(continued)

5.5.9.4 Acceptance Criteria (continued) [Unit 2 only]

9. Tube repair refers to mechanical sleeving, as described by Westinghouse report WCAP-11178, Rev. 1, or laser welded sleeving, as described by Westinghouse reports WCAP-13088, Revision 4, and WCAP-14740 dated January 1997, which is used to maintain a tube in service or return a tube to service. This includes the removal of plugs that were installed as a corrective or preventive measure.

10. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed ~~after the field hydrostatic test and prior to initial POWER OPERATOIN~~ using the equipment and techniques expected to be used during subsequent inservice inspections.

11. ~~(For Unit 2 only)~~ F* Distance is the distance of the expanded portion of a tube which provides a sufficient length of undegraded tube expansion to resist pullout of the tube from the tubesheet. The F* distance is equal to 1.60 inches plus allowance for eddy current uncertainty measurement and is measured down from the top of the tube sheet or the bottom of the roll transition, whichever is lower in elevation. The allowance for eddy current uncertainty is documented in the steam generator eddy current inspection procedure.

12. ~~(For Unit 2 only)~~ F* Tube is a tube:

    a. with degradation equal to or greater than 40% below the F* distance, and

    b. which has no indication of imperfections greater than or equal to 20% of nominal wall thickness within the F* distance, and

    c. that remains inservice.

(continued)

5.5.9.4 Acceptance Criteria (continued)

[Unit 2 only]

13. ~~(For Unit 2 only)~~ Tube Expansion is that portion of a tube which has been increased in diameter by a rolling process such that no crevice exists between the outside diameter of the tube and the hole in the tubesheet. Tube expansion also refers to that portion of a sleeve which has been increased in diameter by a rolling process such that no crevice exists between the outside diameter of the sleeve and the parent steam generator tube.

14. Tube Support Plate Repair Limit is used for the disposition of an alloy 600 steam generator tube for continued service that is experiencing predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates. At tube support plate intersections, the repair limit is based on maintaining steam generator tube serviceability as described below:

a. Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with bobbin voltage less than or equal to the lower voltage repair limit (2.0 volts), will be allowed to remain in service.

b. Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than the lower voltage repair limit (2.0 volts), will be repaired or plugged except as noted in 5.5.9.4.a.14.c below.

(continued)

5.5.9.4 Acceptance Criteria (continued)

Δt	=	length of time since last scheduled inspection during which V_{URL} and V_{LRL} were implemented
CL	=	cycle length (the time between two scheduled steam generator inspections)
V_{SL}	=	structural limit voltage
Gr	=	average growth rate per cycle length
NDE	=	95-percent cumulative probability allowance for nondestructive examination uncertainty (i.e., a value of 20 percent has been approved by NRC)

Implementation of these mid-cycle repair limits should follow the same approach as in TS 5.5.9.4.a.14.a, 5.5.9.4.a.14.b, and 5.5.9.4.a.14.c.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug ~~or repair~~ of all tubes exceeding the plugging ~~or repair limit~~) required by Tables 5.5.9-2 and 5.5.9-3.

[Unit 2 only: or repair]

[Unit 2 only: or repair limit]

Table 5.5.9-2
Steam Generator Tube Inspection

	1st Sample Inspection		2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G.	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug ~~or repair~~ defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug ~~or repair~~ defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug ~~or repair~~ defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., plug ~~or repair~~ defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to 10 CFR 50.73	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s C-2 but no additional S.G.s are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug ~~or repair~~ defective tubes. Notification to NRC pursuant to 10 CFR 50.73	N/A	N/A

$S = \frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

[~~(~~For Unit 2 only — NOTE: F* tubes do not have to be plugged or repaired.~~)~~]

[Unit 2 only: or repair]

[Unit 2 only]

Table 5.5.9-3
Steam Generator Repaired Tube Inspection

	1st Sample Inspection		2nd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required
A minimum of 20% of repaired tubes (1)(2)	C-1	None	N/A	N/A
	C-2	Plug or repair defective repaired tubes and inspect 100% of the repaired tubes in this steam generator	C-1	None
			C-2	Plug or repair defective repaired tubes.
			C-3	Perform action for C-3 result of first sample.
	C-3	Inspect all repaired tubes in this steam generator, plug or repair defective tubes and inspect 20% of the repaired tubes in each steam generator Notification to NRC pursuant to 10CFR50.72(b)(2).	All other steam generators are C-1.	None
			Some steam generators C-2 but no additional steam generators are C-3.	Perform action for C-2 result of first sample.
			Additional steam generator is C-3.	Inspect all repaired tubes in each steam generator and plug or repair defective tubes. Notification to NRC pursuant to 10CFR50.72(b)(2).

(1) Each repair method is considered a separate population for determination of scope expansion.
(2) The inspection of repaired tubes may be performed on tubes from 1 to 3 steam generators based on outage plans.

5.5.15 Safety Function Determination Program (SFDP) (continued)

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Main Steamline Inspection Program

The three main steamlines from the rigid anchor points of the containment penetrations downstream to and including the main steam header shall be inspected. The extent of the inservice examinations completed during each inspection interval (IWA 2400, ASME Code, 1974 Edition, Section XI) shall provide 100 percent volumetric examination of circumferential and longitudinal pipe welds to the extent practical. The areas subject to examination are those defined in accordance with examination category C-G for Class 2 piping welds in Table IWC-2520.

5.5.17 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of containment as required by 10 CFR 50.54 (o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is ~~43 psig.~~

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

[Unit 1 only: 43.8 psig] [Unit 2 only: 43 psig]

(continued)

5.6.7 EDG Failure Report

If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures shall be reported within 30 days. Reports on EDG failures shall include a description of the failures, underlying causes, and corrective actions taken per the Emergency Diesel Generator Reliability Monitoring Program.

5.6.8 PAM Report

When a report is required by Condition B or G of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.9 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Pre-stressed Concrete Containment Tendon Surveillance Program shall be reported to the NRC within 30 days. The report shall include a description of the tendon condition, the condition of the concrete (especially at tendon anchorages), the inspection procedures, the tolerances on cracking, and the corrective action taken.

Inspection

[Unit 2 only: repaired or designated F*]

5.6.10 Steam Generator Tube ~~Inspector~~ Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged, ~~repaired (for Unit 2 only: or designated F*)~~, in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging ~~or repair effort~~.

b. The complete results of the steam generator tube ~~and sleeve~~ inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

[Unit 2 only: or repair effort]

[Unit 2 only: and sleeve]

(continued)

[Unit 2 only: and sleeves]

5.6.10 Steam Generator Tube ~~Inspector~~ Report (continued)

1. Number and extent of tubes ~~and sleeves~~ inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged ~~or repaired~~.

[Unit 2 only: or repaired]

Reportable Event

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a ~~REPORTABLE EVENT~~ and shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. The written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

[Unit 2 only]

d. For implementation of the voltage-based repair criteria to tube support plate intersections, notify the NRC staff prior to returning the steam generators to service (Mode 4) should any of the following conditions arise:

1. If estimated leakage based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds the leak limit (detemined from the licensing basis dose calculation for the postulated main steam line break) for the next operating cycle.

2. If circumferential crack-like indications are detected at the tube support plate intersections.

3. If indications are identified that extend beyond the confines of the tube support plate.

4. If indications are identified at the tube support plate elevations that are attributable to primary water stress corrosion cracking.

5. If the calculated conditional burst probability based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds 1×10^{-2}, notify the NRC and provide an assessment of the safety significance of the occurrence.

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

Unit 1

Typed Pages

Table 3.3.1-1 (page 4 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
11.	Reactor Coolant Pump (RCP) Breaker Position						
	a. Single Loop	$1^{(g)}$	1 per RCP	N	SR 3.3.1.12	NA	NA
	b. Two Loops	$1^{(h)}$	1 per RCP	M	SR 3.3.1.12	NA	NA
12.	Undervoltage RCPs	$1^{(f)}$	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 2640 V	≥ 2680 V
13.	Underfrequency RCPs	$1^{(f)}$	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 56.9 Hz	≥ 57 Hz
14.	Steam Generator (SG) Water Level — Low Low	1,2	3 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.14	≥ 27.6% (k) ≥ 24.6% (l)	≥ 28% (k) ≥ 25% (l)

(f) Above the P-7 (Low Power Reactor Trips Block) interlock.

(g) Above the P-8 (Power Range Neutron Flux) interlock.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(k) Unit 1 only (after Steam Generator Replacement)

(l) Unit 2 only (before Steam Generator Replacement)

Table 3.3.2-1 (page 4 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
5. Turbine Trip and Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1,2(g)	2 trains	H	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
b. SG Water Level - High High (P-14)	1,2(g)	3 per SG	I	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	≤ 82.4% (h) ≤ 78.9% (i)	≤ 82% (h) ≤ 78.5% (i)
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. Auxiliary Feedwater						
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
b. SG Water Level - Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	≥ 27.6% (h) ≥ 24.6% (i)	≥ 28% (h) ≥ 25% (i)
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
d. Undervoltage Reactor Coolant Pump	1,2	2 per bus	I	SR 3.3.2.5 SR 3.3.2.7	≥ 2640 volts	≥ 2680 volts
e. Trip of all Main Feedwater Pumps	1	2 per pump	J	SR 3.3.2.10	NA	NA
7. ESFAS Interlocks						
a. Reactor Trip, P-4	1,2,3	1 per train, 2 trains	F	SR 3.3.2.6	NA	NA
b. Pressurizer Pressure, P-11	1,2,3	3	K	SR 3.3.2.7	≤ 2003 psig	≤ 2000 psig
c. T_{avg} - Low Low, P-12 (Decreasing) (Increasing)	1,2,3	1 per loop	K	SR 3.3.2.7	≥ 542.6°F ≤ 545.4°F	≥ 543°F ≤ 545°F

(g) Except when all Main Feedwater lines are isolated by either a Main Feedwater Stop Valve or an MFRV and associated bypass valve or by a closed manual valve.

(h) Unit 1 only (after Steam Generator Replacement)

(i) Unit 2 only (before Steam Generator Replacement)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range) for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

ACTIONS

C.1 and C.2 (continued)

inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened.

The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] for required RCS loops. If the SG secondary side wide range water level

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

is < [Unit 1 only: 75%] [Unit 2 only: 74%], the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES

None.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required RHR loop inoperable. <u>AND</u> Two required RCS loops inoperable.	B.1 Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. <u>OR</u> No RCS or RHR loop in operation.	C.1 Suspend all operations involving a reduction of RCS boron concentration. <u>AND</u> C.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water levels are ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range) for required RCS loops.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ≥ [Unit 1 only: 75%] [Unit 2 only: 74%]. If the SG secondary side wide range water level is < [Unit 1 only: 75%] [Unit 2 only: 74%], the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.

3.4.7 RCS Loops — MODE 5, Loops Filled

LCO 3.4.7

One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range).

--NOTES--

1. The RHR pump of the loop in operation may not be in operation for ≤ 2 hours per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ 325°F unless:

   a. The secondary side water temperature of each SG is < 50°F above each of the RCS cold leg temperatures; or

   b. The pressurizer water volume is less than 770 cubic feet (24% of wide range, cold, pressurizer level indication).

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

5. The number of operating Reactor Coolant Pumps is limited to one at RCS temperatures < 110°F with the exception that a second pump may be started for the purpose of maintaining continuous flow while taking the operating pump out of service.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side water levels not within limits.	A.1	Initiate action to restore a second RHR loop to OPERABLE status.	Immediately
	OR		
	A.2	Initiate action to restore required SG secondary side water levels to within limits.	Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side water level is ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range) in required SGs.	12 hours

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation (Ref. 1) are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range) to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops — MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range). One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range). Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to not be in operation ≤ 2 hours per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 2 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration

(continued)

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range).

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels < [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range), redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal.

The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side wide range water levels are ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥ [Unit 1 only: 75%] [Unit 2 only: 74%] (wide range) in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE;

d. 450 gallons per day total primary to secondary LEAKAGE through all steam generators (SGs); and

e. 150 gallons per day primary to secondary LEAKAGE through any one SG.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is typically seen as a precursor to a LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 150 gpd per SG primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The FSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via the main steam safety valves. The majority of the activity released to the atmosphere results from the tube rupture. Therefore, the 150 gpd per SG primary to secondary LEAKAGE is inconsequential.

[Unit 1 Only] The SLB is more limiting for primary to secondary LEAKAGE. The safety analysis for the SLB assumes 500 gpd and 470 gpd primary to secondary LEAKAGE in the ruptured and intact steam generators respectively as an initial condition. The dose consequences resulting from the SLB accident are bounded by a small fraction (i.e., 10%) of the limits defined in 10 CFR 100. The RCS specific activity assumed was a bounding value of 1.0 μCi/gm DOSE EQUIVALENT I-131, with either a pre-existing or an accident initiated iodine spike. These values bound the Technical Specifications values.

[Unit 2 Only] The SLB is more limiting for primary to secondary LEAKAGE. The safety analysis for the SLB assumes 500 gpd primary to secondary LEAKAGE in one steam generator as an initial condition. The Unit 2 MSLB analysis in support of Generic Letter 95-05 has shown that steam generator tube leakage of 23.8 gpm in the faulted loop, and 0.1 gpm (approximately 150 gpd) in each of the intact loops (total leakage of 24 gpm), following an SLB outside of containment, but upstream of the main steam isolation valves, results in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines. The RCS specific activity assumed was 0.15 μCi/gm DOSE EQUIVALENT I-131, with either a pre-existing or an accident initiated iodine spike. These values bound the Technical Specifications values.

The RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through All Steam Generators (SGs)

The limits for total primary to secondary LEAKAGE through all SGs produce acceptable offsite doses in the SLB accident analysis. Violation of this LCO could exceed the offsite dose limits for this accident. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

(continued)

LCO (continued)

e. Primary to Secondary LEAKAGE through Any One SG

The limit on one SG is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line rupture. If leaked through many cracks, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary

(continued)

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 [Unit 1 Only: > 0.5 μCi/gm.] [Unit 2 Only: > 0.15 μCi/gm.]	------------------Note------------------ LCO 3.0.4 is not applicable. --	
	A.1 Verify DOSE EQUIVALENT I-131 within the acceptable region of Figure 3.4.16-1.	Once per 4 hours
	<u>AND</u>	
	A.2 Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit.	B.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met. <u>OR</u> DOSE EQUIVALENT I-131 in the unacceptable region of Figure 3.4.16-1.	C.1 Be in MODE 3 with $T_{avg} < 500°F$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity $\leq 100/\bar{E}$ μCi/gm.	7 days
SR 3.4.16.2	------------------------------NOTE------------------------------ Only required to be performed in MODE 1. --- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity [Unit 1 Only: ≤ 0.5 μCi/gm.] [Unit 2 Only: ≤ 0.15 μCi/gm.]	14 days <u>AND</u> Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

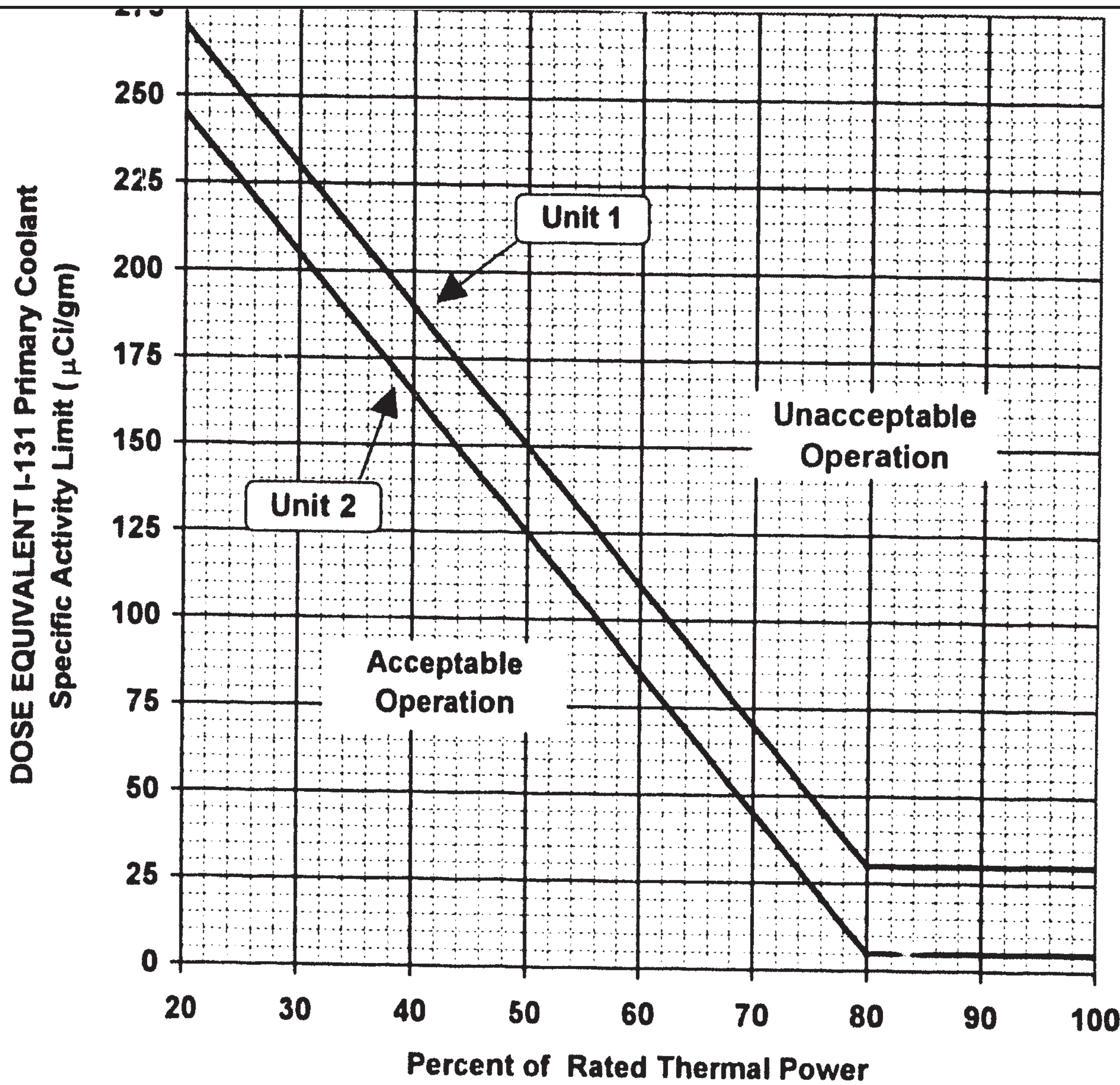

Figure 3.4.16-1 (page 1 of 1)

DOSE EQUIVALENT I-131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity > [Unit 1 only: 0.5 μCi/gm] [Unit 2 only: 0.15 μCi/gm] DOSE EQUIVALENT I-131.

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident, or for the duration of the accident at the Low Population Zone, is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to an appropriate fraction of the 10 CFR 100 limits (i.e., a small fraction of or well within the 10 CFR 100 limits depending on the specific accident analysis) during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) or main steam line break (MSLB) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to an appropriate fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR or main steam line break (MSLB) accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting doses will not exceed an appropriate fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at [Unit 1 only: 1.0 μCi/gm] [Unit 2 only: 0.5 μCi/gm] and a bounding reactor coolant steam generator (SG) tube leakage of [Unit 1 only: 1 gpm total for three SGs] [Unit 2 only: 150 gpd per SG]. The MSLB analysis assumes a SG tube leakage of [Unit 1 only: 500 gpd] [Unit 2 only: 23.8 gpm] in the faulted loop and [Unit 1 only: 470 gpd] [Unit 2 only: 150 gpd] in each of the intact loops for a total leakage of [Unit 1 only: 1440 gpd] [Unit 2 only: 24 gpm].

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APPLICABLE SAFETY ANALYSES (continued)

This analysis resulted in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines using ICRP 30 Dose Conversion Factors (DCFs). The initial RCS specific activity assumed was [Unit 1 only: 1.0 μCi/gm] [Unit 2 only: 0.15 μCi/gm] DOSE EQUIVALAENT I-131 with an iodine spike. These values bound the Technical Specifications values. The safety analysis assumes for both the SGTR and MSLB the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.16, "Secondary Specific Activity."

The analysis for the MSLB accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The SGTR analysis assumes an RCS coolant activity of [Unit 1 only: 1.0 μCi/gm] [Unit 2 only: 0.5 μCi/gm] DOSE EQUIVALAENT I-131. The MSLB analysis considers two cases of reactor coolant specific activity. One case assumes specific activity at [Unit 1 only: 1.0 μCi/gm] [Unit 2 only: 0.15 μCi/gm] DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the I-131 activity release rate into the reactor coolant by a factor of 500 immediately after the accident. The second case assumes the initial reactor coolant iodine activity at [Unit 1 only: 60 μCi/gm] [Unit 2 only: 9 μCi/gm] DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. These values bound the Technical Specifications values. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of $100/\bar{E}$ μCi/gm for gross specific activity.

The SGTR analysis also assumes a loss of offsite power coincident with a reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

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APPLICABLE SAFETY ANALYSES (continued)

The main steam line break (MSLB) analysis assumes a double-ended guillotine break of a main steamline outside of containment. The affected steam generator will rapidly depressurize and release both the radionuclides initially contained in the secondary coolant, and the primary coolant activity transferred via SG tube leakage, directly to the outside atmosphere. A portion of the iodine activity initially contained in the intact SGs and noble gas activity due to SG tube leakage is released to the atmosphere through either the SG atmospheric relief valves (ARVs) or the SG safety relief valves.

The safety analysis assumes an accident initiated iodine spike and shows the radiological consequences of a MSLB accident are within a small fraction of the Reference 1 dose guideline limits.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1, in the applicable specification, for more than 48 hours. The MSLB safety analysis has concurrent and pre-accident iodine spiking levels up to [Unit 1 only: 60.0 μCi/gm] [Unit 2 only: 9.0 μCi/gm] DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a MSLB accident occurring during the established 48 hour time limit. The occurrence of a MSLB accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

The limits on RCS specific activity are also used for establishing standardization in plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement.

LCO

The specific iodine activity is limited to 0.5 μCi/gm DOSE EQUIVALENT I-131 for the SGTR analysis and [Unit 1 only: 0.5 μCi/gm] [Unit 2 only: 0.15 μCi/gm] DOSE EQUIVALENT I-131 for the MSLB analysis, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the thyroid dose to an individual during the Design Basis Accident (DBA) will be an appropriate fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose.

(continued)

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed; and

d. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day for the first 24 hours and 0.075% thereafter (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from a LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.15% per day in the safety analysis at P_a = [Unit 1 only: 43.8 psig] [Unit 2 only: 43 psig] (Ref. 3).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of the NRC Policy Statement.

BASES

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B, as the maximum allowable containment leakage rate at the calculated peak containment internal pressure, P_a = [Unit 1 only: 43.8 psig)] [Unit 2 only: 43 psig] following a LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of the NRC Policy Statement.

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. The worst case SLB generates larger mass and energy release than the worst case LOCA. Thus, the SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 17.7 psia (3.0 psig). This resulted in a maximum peak pressure from a SLB of [Unit 1 only: 52.0 psig] [Unit 2 only: 52.4 psig]. The containment analysis (Ref. 1) shows the maximum peak calculated containment pressure, P_a, resulting from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA, [Unit 1 only: 43.8 psig] [Unit 2 only: 43 psig] does not exceed the containment design pressure, 54 psig.

The containment was also designed for an external pressure load equivalent to –3.0 psig. The inadvertent actuation of the Containment

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 127°F. This resulted in a maximum containment air temperature of [Unit 1 only: 367°F] [Unit 2 only: 383°F]. The design air temperature is 378°F.

[Unit 1 only] The temperature limit is used to establish the environmental qualification operating envelope for containment. The basis of the containment design air temperature is to ensure the performance of safety-related equipment inside containment (Ref. 2). Thermal analyses show that the containment air temperature remains below the equipment design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

[Unit 2 only] The temperature limit is used to establish the environmental qualification operating envelope for containment. The maximum peak containment air temperature was calculated to exceed the containment design air temperature for only a few seconds during the transient. The basis of the containment design air temperature, however, is to ensure the performance of safety-related equipment inside containment (Ref. 2). Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design air temperature was short enough that the equipment surface temperatures remained below the equipment design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a SLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded. Containment average air temperature satisfies Criterion 2 of the NRC Policy Statement.
LCO	During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant containment structure peak accident temperature is maintained below the containment design temperature. As a result, the ability of containment to perform its design function is ensured.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.
ACTIONS	<u>A.1</u> When containment average air temperature is not within the limit of the LCO, it must be restored to within limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems. <u>B.1 and B.2</u> If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

BACKGROUND

Containment Cooling System (continued)

ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, unless an LOSP signal is present, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If an LOSP signal is present, only the two fans selected (one per train) will receive an auto-start signal and will start in slow speed. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. In addition, if temperature at the cooler discharge reaches 135°F, fusible links holding dropout plates will open and the fan discharge will no longer be directed through the common discharge header. This function helps to protect the fans in a post-accident environment by reducing the back pressure on the fans. The temperature of the SW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is [Unit 1 only: 52.0 psig] [Unit 2 only: 52.4 psig] (experienced during an SLB). The analysis shows that the peak containment temperature is [Unit 1 only: 367°F] [Unit 2 only: 383°F] (experienced during a SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.)

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.16 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 450 gallons per day tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of [Unit 1 only: 0.5 μCi/gm] [Unit 2 only: 0.15 μCi/gm] (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives (i.e., < 20 hours).

With the specified activity limit, the resultant 2 hour thyroid dose to a person at the site boundary would be within the limits of 10 CFR 20.1-20.601 if the main steam safety valves (MSSVs) and Atmospheric Relief Valves (ARVs) are open for 2 hours following a trip from full power.

Operating at the allowable limits results in a 2 hour site boundary exposure well within the 10 CFR 100 (Ref. 1) limits.

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological

(continued)

5.5 Programs and Manuals

5.5.8 Inservice Testing Program (continued)

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.9 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies. [Specification 5.5.9 is not required to be performed on the replacement steam generators during the shutdown when the steam generators are replaced.]

5.5.9.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.9.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.9-1.

5.5.9.2 Steam Generator Tube# Sample Selection and Inspection

5.5.9.2.1 The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Tables 5.5.9-2 and 5.5.9-3. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.9.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.9.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. [Unit 2 only: Selection of tubes to be inspected is not affected by the F* designation. When applying the exceptions of 5.5.9.2.1.a through 5.5.9.2.1.c, previous defects or imperfections in the area repaired by sleeving are not considered an area requiring reinspection]. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

[Unit 2 only] When referring to a steam generator tube, the sleeve shall be considered a part of the tube if the tube has been repaired per Specification 5.5.9.4.a.9.

(continued)

5.5.9.2.1 (continued)

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 5.5.9.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube [Unit 2 only: or sleeve inspection], this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

4. [Unit 2 only] Indications left in service as a result of application of the tube support plate voltage-based repair criteria shall be inspected by bobbin coil probe during all future refueling outages.

c. The tubes selected as the second and third samples (if required by Tables 5.5.9-2 and 5.5.9-3) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

(continued)

5.5.9.2.1 (continued)

d. [Unit 2 only] Implementation of the steam generator tube/tube support plate repair criteria requires a 100 percent bobbin coil inspection for hot-leg and cold-leg tube support plate intersections down to the lowest cold-leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes or sleeves must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.9.2.2 [Unit 2 only] Steam Generator F* Tube Inspection

In addition to the minimum sample size as determined by Specification 5.5.9.2.1, all F* tubes will be inspected within the tubesheet region. The results of this inspection will not be a cause for additional inspections per Tables 5.5.9-2 and 5.5.9-3.

5.5.9.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Tables 5.5.9-2 and 5.5.9-3 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.9.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Tables 5.5.9-2 and 5.5.9-3 during the shutdown subsequent to any of the following conditions:

(continued)

5.5 Programs and Manuals

5.5.9.3 Inspection Frequencies (continued)

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.13.

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

5.5.9.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube [Unit 2 only: or sleeve] from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube [Unit 2 only: or sleeve].

3. Degraded Tube means a tube, [Unit 2 only: including the sleeve if the tube has been repaired], that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube [Unit 2 only: or sleeve] wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging [Unit 2 only: or repair limit]. A tube [Unit 2 only: or sleeve] containing a defect is defective.

(continued)

5.5.9.4 Acceptance Criteria (continued)

6. [Unit 1 Only] Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness.

   [Unit 2 only] Plugging or Repair Limit means the imperfection depth at or beyond which the tube shall be repaired (i.e., sleeved) or removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness. This definition does not apply for tubes that meet the F* criteria. For a tube that has been sleeved with a mechanical joint sleeve, through wall penetration of greater than or equal to 31% of sleeve nominal wall thickness in the sleeve requires the tube to be removed from service by plugging. For a tube that has been sleeved with a welded joint sleeve, through wall penetration greater than or equal to 24% of sleeve nominal wall thickness in the sleeve between the weld joints requires the tube to be removed from service by plugging. This definition does not apply to tube support plate intersections for which the voltage-based repair criteria are being applied. Refer to 5.5.9.4.a.14 for the repair limit applicable to these intersections. For a tube with an imperfection or flaw in the tube sheet below the lower joint for an installed elevated laser welded sleeve, no repair or plugging is required provided the installed sleeve meets all sleeved tube inspection requirements.

7. Unserviceable describes the condition of a tube [Unit 2 only: or sleeve] if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.9.3.c, above.

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5.5.9.4 Acceptance Criteria (continued)

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg. [Unit 2 only: For a tube with a tube sheet sleeve installed, the point of entry is the bottom of the tube sheet sleeve below the lower sleeve joint. For a tube that has been repaired by sleeving, the tube inspection should include the sleeved portion of the tube.]

9. [Unit 2 only] Tube repair refers to mechanical sleeving, as described by Westinghouse report WCAP-11178, Rev. 1, or laser welded sleeving, as described by Westinghouse reports WCAP-13088, Revision 4, and WCAP-14740, which is used to maintain a tube in service or return a tube to service. This includes the removal of plugs that were installed as a corrective or preventive measure.

10. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed using the equipment and techniques expected to be used during subsequent inservice inspections.

11. [Unit 2 only] F* Distance is the distance of the expanded portion of a tube which provides a sufficient length of undegraded tube expansion to resist pullout of the tube from the tubesheet. The F* distance is equal to 1.60 inches plus allowance for eddy current uncertainty measurement and is measured down from the top of the tube sheet or the bottom of the roll transition, whichever is lower in elevation. The allowance for eddy current uncertainty is documented in the steam generator eddy current inspection procedure.

(continued)

5.5 Programs and Manuals

5.5.9.4 Acceptance Criteria (continued)

12. [Unit 2 only] F* Tube is ¯ tube:

    a. with degradation equal to or greater than 40% below the F* distance, and

    b. which has no indication of imperfections greater than or equal to 20% of nominal wall thickness within the F* distance, and

    c. that remains inservice.

13. [Unit 2 only] Tube Expansion is that portion of a tube which has been increased in diameter by a rolling process such that no crevice exists between the outside diameter of the tube and the hole in the tubesheet. Tube expansion also refers to that portion of a sleeve which has been increased in diameter by a rolling process such that no crevice exists between the outside diameter of the sleeve and the parent steam generator tube.

14. [Unit 2 only] Tube Support Plate Repair Limit is used for the disposition of an alloy 600 steam generator tube for continued service that is experiencing predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates. At tube support plate intersections, the repair limit is based on maintaining steam generator tube serviceability as described below:

    a. Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with bobbin voltage less than or equal to the lower voltage repair limit (2.0 volts), will be allowed to remain in service.

    b. Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than the lower voltage repair limit (2.0 volts), will be repaired or plugged except as noted in 5.5.9.4.a.14.c below.

(continued)

5.5 Programs and Manuals

5.5.9.4 Acceptance Criteria (continued)

Δt	=	length of time since last scheduled inspection during which V_{URL} and V_{LRL} were implemented
CL	=	cycle length (the time between two scheduled steam generator inspections)
V_{SL}	=	structural limit voltage
Gr	=	average growth rate per cycle length
NDE	=	95-percent cumulative probability allowance for nondestructive examination uncertainty (i.e., a value of 20 percent has been approved by NRC)

Implementation of these mid-cycle repair limits should follow the same approach as in TS 5.5.9.4.a.14.a, 5.5.9.4.a.14.b, and 5.5.9.4.a.14.c.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug [Unit 2 only: or repair] of all tubes exceeding the plugging [Unit 2 only: or repair limit]) required by Tables 5.5.9-2 and 5.5.9-3.

Table 5.5.9-2
Steam Generator Tube Inspection

	1st Sample Inspection		2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G.	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug [Unit 2 only: or repair] defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug [Unit 2 only: or repair] defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug [Unit 2 only:or repair] defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., plug [Unit 2 only: or repair] defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to 10 CFR 50.73	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s C-2 but no additional S.G.s are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug [Unit 2 only: or repair] defective tubes. Notification to NRC pursuant to 10 CFR 50.73	N/A	N/A

$S = \frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

[Unit 2 only – NOTE: F* tubes do not have to be plugged or repaired.]

Table 5.5.9-3
Steam Generator Repaired Tube Inspection
[Unit 2 only]

	1st Sample Inspection		2nd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required
A minimum of 20% of repaired tubes (1)(2)	C-1	None	N/A	N/A
	C-2	Plug or repair defective repaired tubes and inspect 100% of the repaired tubes in this steam generator	C-1	None
			C-2	Plug or repair defective repaired tubes.
			C-3	Perform action for C-3 result of first sample.
	C-3	Inspect all repaired tubes in this steam generator, plug or repair defective tubes and inspect 20% of the repaired tubes in each steam generator Notification to NRC pursuant to 10CFR50.72(b)(2).	All other steam generators are C-1.	None
			Some steam generators C-2 but no additional steam generators are C-3.	Perform action for C-2 result of first sample.
			Additional steam generator is C-3.	Inspect all repaired tubes in each steam generator and plug or repair defective tubes. Notification to NRC pursuant to 10CFR50.72(b)(2).

(1) Each repair method is considered a separate population for determination of scope expansion.
(2) The inspection of repaired tubes may be performed on tubes from 1 to 3 steam generators based on outage plans.

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Main Steamline Inspection Program

The three main steamlines from the rigid anchor points of the containment penetrations downstream to and including the main steam header shall be inspected. The extent of the inservice examinations completed during each inspection interval (IWA 2400, ASME Code, 1974 Edition, Section XI) shall provide 100 percent volumetric examination of circumferential and longitudinal pipe welds to the extent practical. The areas subject to examination are those defined in accordance with examination category C-G for Class 2 piping welds in Table IWC-2520.

5.5.17 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of containment as required by 10 CFR 50.54 (o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is [Unit 1 only: 43.8 psig] [Unit 2 only: 43 psig].

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

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5.6 Reporting Requirements

5.6.7 EDG Failure Report

If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures shall be reported within 30 days. Reports on EDG failures shall include a description of the failures, underlying causes, and corrective actions taken per the Emergency Diesel Generator Reliability Monitoring Program.

5.6.8 PAM Report

When a report is required by Condition B or G of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.9 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Pre-stressed Concrete Containment Tendon Surveillance Program shall be reported to the NRC within 30 days. The report shall include a description of the tendon condition, the condition of the concrete (especially at tendon anchorages), the inspection procedures, the tolerances on cracking, and the corrective action taken.

5.6.10 Steam Generator Tube Inspection Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged, [Unit 2 only: repaired or designated F*] in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging [Unit 2 only: or repair effort].

b. The complete results of the steam generator tube [Unit 2 only: and sleeve] inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

(continued)

5.6 Reporting Requirements

5.6.10 Steam Generator Tube Inspection Report (continued)

1. Number and extent of tubes [Unit 2 only: and sleeves] inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged [Unit 2 only: or repaired].

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a Reportable Event and shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. The written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

d. [Unit 2 only] For implementation of the voltage-based repair criteria to tube support plate intersections, notify the NRC staff prior to returning the steam generators to service (Mode 4) should any of the following conditions arise:

1. If estimated leakage based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds the leak limit (determined from the licensing basis dose calculation for the postulated main steam line break) for the next operating cycle.

2. If circumferential crack-like indications are detected at the tube support plate intersections.

3. If indications are identified that extend beyond the confines of the tube support plate.

4. If indications are identified at the tube support plate elevations that are attributable to primary water stress corrosion cracking.

5. If the calculated conditional burst probability based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds 1×10^{-2}, notify the NRC and provide an assessment of the safety significance of the occurrence.

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

Unit 2

Changed Pages List

The pages provided in this section will be issued prior to Unit 2 entering MODE 5 for Cycle 15 (Spring 2001).

Pages noted with an '*' have changed only due to information rolling over from one page to another.

Page	Revision	Page	Revision	Page	Revision
3.3.1-17	Replace	B 3.4.16-1	Replace	5.5-15 *	Replace
3.3.2-11	Replace	B 3.4.16-2	Replace	5.5-16 *	Replace
3.4.5-3	Replace	B 3.4.16-3	Replace	5.5-17	Replace
B 3.4.5-5	Replace	B 3.6.1-2	Replace	5.5-18 *	Replace
B 3.4.5-6	Replace	B 3.6.2-2	Replace	5.5-19	Delete
3.4.6-2	Replace	B 3.6.4-1	Replace	5.5-20	Delete
B 3.4.6-5	Replace	B 3.6.5-2	Replace	5.5-21	Delete
3.4.7-1	Replace	B 3.6.6-3	Replace	5.5-22	Delete
3.4.7-2	Replace	B 3.7.16-1	Replace	5.5-23	Delete
B 3.4.7-1	Replace	5.5-5	Replace	5.5-24	Delete
B 3.4.7-2	Replace	5.5-6	Replace	5.5-25	Delete
B 3.4.7-4	Replace	5.5-7	Replace	5.6-5	Replace
B 3.4.7-5	Replace	5.5-8	Replace	5.6-6	Replace
3.4.13-1	Replace	5.5-9	Replace		
B 3.4.13-2	Replace	5.5-10 *	Replace		
3.4.16-1	Replace	5.5-11	Replace		
3.4.16-2	Replace	5.5-12 *	Replace		
3.4.16-4	Replace	5.5-13 *	Replace		
		5.5-14 *	Replace		

Table 3.3.1-1 (page 4 of 8)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
11. Reactor Coolant Pump (RCP) Breaker Position						
a. Single Loop	1(g)	1 per RCP	N	SR 3.3.1.12	NA	NA
b. Two Loops	1(h)	1 per RCP	M	SR 3.3.1.12	NA	NA
12. Undervoltage RCPs	1(f)	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 2640 V	≥ 2680 V
13. Underfrequency RCPs	1(f)	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 56.9 Hz	≥ 57 Hz
14. Steam Generator (SG) Water Level — Low Low	1,2	3 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.14	~~≥ 24.0%~~ ≥ 27.6%	~~≥ 25%~~ ≥ 28%

(f) Above the P-7 (Low Power Reactor Trips Block) interlock.

(g) Above the P-8 (Power Range Neutron Flux) interlock.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

Table 3.3.2-1 (page 4 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
5. Turbine Trip and Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1,2(g)	2 trains	H	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
b. SG Water Level - High High (P-14)	1,2(g)	3 per SG	I	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	~~≤ 78.9%~~ ≤ 82.4%	~~≤ 78.5%~~ ≤ 82%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. Auxiliary Feedwater						
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
b. SG Water Level - Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	~~≥ 24.8%~~ ≥ 27.6%	~~≥ 25%~~ ≥ 28%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
d. Undervoltage Reactor Coolant Pump	1,2	2 per bus	I	SR 3.3.2.5 SR 3.3.2.7	≥ 2640 volts	≥ 2680 volts
e. Trip of all Main Feedwater Pumps	1	2 per pump	J	SR 3.3.2.10	NA	NA
7. ESFAS Interlocks						
a. Reactor Trip, P-4	1,2,3	1 per train, 2 trains	F	SR 3.3.2.6	NA	NA
b. Pressurizer Pressure, P-11	1,2,3	3	K	SR 3.3.2.7	≤ 2003 psig	≤ 2000 psig
c. T_{avg} - Low Low, P-12 (Decreasing) (Increasing)	1,2,3	1 per loop	K	SR 3.3.2.7	≥ 542.6°F ≤ 545.4°F	≥ 543°F ≤ 545°F

(g) Except when all Main Feedwater lines are isolated by either a Main Feedwater Stop Valve or an MFRV and associated bypass valve or by a closed manual valve.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.2	Verify steam generator secondary side water levels are ~~≥ 74%~~ (wide range) for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

≥ 75 %

ACTIONS

C.1 and C.2 (continued)

inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened.

The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ~~≥ 74%~~ for required RCS loops. If the SG

≥ 75 %

(continued)

BASES 75 %

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

secondary side wide range water level is < ~~74%~~, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES

None.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required RHR loop inoperable. AND Two required RCS loops inoperable.	B.1 Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1 Suspend all operations involving a reduction of RCS boron concentration. AND C.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water levels are ~~≥ 74%~~ (wide range) for required RCS loops.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

≥ 75 %

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ≥ ~~74%~~. If the SG secondary side wide range water level is < ~~74%~~, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.

3.4.7 RCS Loops — MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be ~~≥ 74%~~ (wide range).

≥ 75 %

---NOTES---

1. The RHR pump of the loop in operation may not be in operation for ≤ 2 hours per 8 hour period provided:

    a. No operations are permitted that would cause reduction of the RCS boron concentration; and

    b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ 325°F unless:

    a. The secondary side water temperature of each SG is < 50°F above each of the RCS cold leg temperatures; or

    b. The pressurizer water volume is less than 770 cubic feet (24% of wide range, cold, pressurizer level indication).

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

5. The number of operating Reactor Coolant Pumps is limited to one at RCS temperatures < 110°F with the exception that a second pump may be started for the purpose of maintaining continuous flow while taking the operating pump out of service.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side water levels not within limits.	A.1	Initiate action to restore a second RHR loop to OPERABLE status.	Immediately
	OR		
	A.2	Initiate action to restore required SG secondary side water levels to within limits.	Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side water level is ~~≥ 74%~~ (wide range) in required SGs.	12 hours

≥ 75 %

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation (Ref. 1) are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels ~~above 74%~~ (wide range) to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

≥ 75 %

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops — MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

$\geq$ 75 %

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ~~$\geq$ 74%~~ (wide range). One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ~~$\geq$ 74%~~ (wide range). Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to not be in operation $\leq$ 2 hours per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 2 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration

(continued)

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ ~~74%~~ (wide range).

75 %

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels < ~~74%~~ (wide range), redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal.

The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side wide range water levels are ~~≥ 74%~~ ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

≥ 75 %

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ~~≥ 74%~~ (wide range) in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE;

d. ~~420 gallons per day for Unit 1 and~~ 450 gallons per day ~~for Unit 2~~ total primary to secondary LEAKAGE through all steam generators (SGs); and

e. ~~140 gallons per day for Unit 1 and~~ 150 gallons per day ~~for Unit 2~~ primary to secondary LEAKAGE through any one SG.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is typically seen as a precursor to a LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 150 gpd per SG primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The FSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via the main steam safety valves. The majority of the activity released to the atmosphere results from the tube rupture. Therefore, the 150 gpd per SG primary to secondary LEAKAGE is inconsequential.

Insert 3

The main steam line break (MSLB) is more limiting for site radiation releases. The MSLB analysis in support of Generic Letter 95-05 has shown that steam generator tube leakage of 23.8 gpm in the faulted loop, and 0.1 gpm (approximately 150 gpd) in each of the intact loops (total leakage of 24 gpm), following a main steam line break outside of containment, but upstream of the main steam isolation valves, results in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines. The RCS specific activity assumed was 0.15 micro-Ci/gm Dose Equivalent I-131, with either a pre-existing or an accident initiated iodine spike.

The RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS operational LEAKAGE shall be limited to:

a. <u>Pressure Boundary LEAKAGE</u>

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher

(continued)

The SLB is more limiting for primary to secondary LEAKAGE. The safety analysis for the SLB assumes 500 gpd and 470 gpd primary to secondary LEAKAGE in the ruptured and intact steam generators respectively as an initial condition. The dose consequences resulting from the SLB accident are bounded by a small fraction (i.e., 10%) of the limits defined in 10 CFR 100. The RCS specific activity assumed was a bounding value of 1.0 μCi/gm DOSE EQUIVALENT I-131, with either a pre-existing or an accident initiated iodine spike. These values bound the Technical Specifications values.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. DOSE EQUIVALENT I-131 ~~> 0.15 µCi/gm.~~ > 0.5 µCi/gm	----------Note---------- LCO 3.0.4 is not applicable. ------------------------		
	A.1	Verify DOSE EQUIVALENT I-131 within the acceptable region of Figure 3.4.16-1.	Once per 4 hours
	AND		
	A.2	Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit.	B.1	Be in MODE 3 with T_{avg} < 500°F.	6 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 in the unacceptable region of Figure 3.4.16-1.	C.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity ≤ 100/$\bar{E}$ µCi/gm.	7 days
SR 3.4.16.2	----------NOTE---------- Only required to be performed in MODE 1. ------------------------------ Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ~~≤ 0.15 µCi/gm.~~ e ≤ 0.5 µCi/gm	14 days AND Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

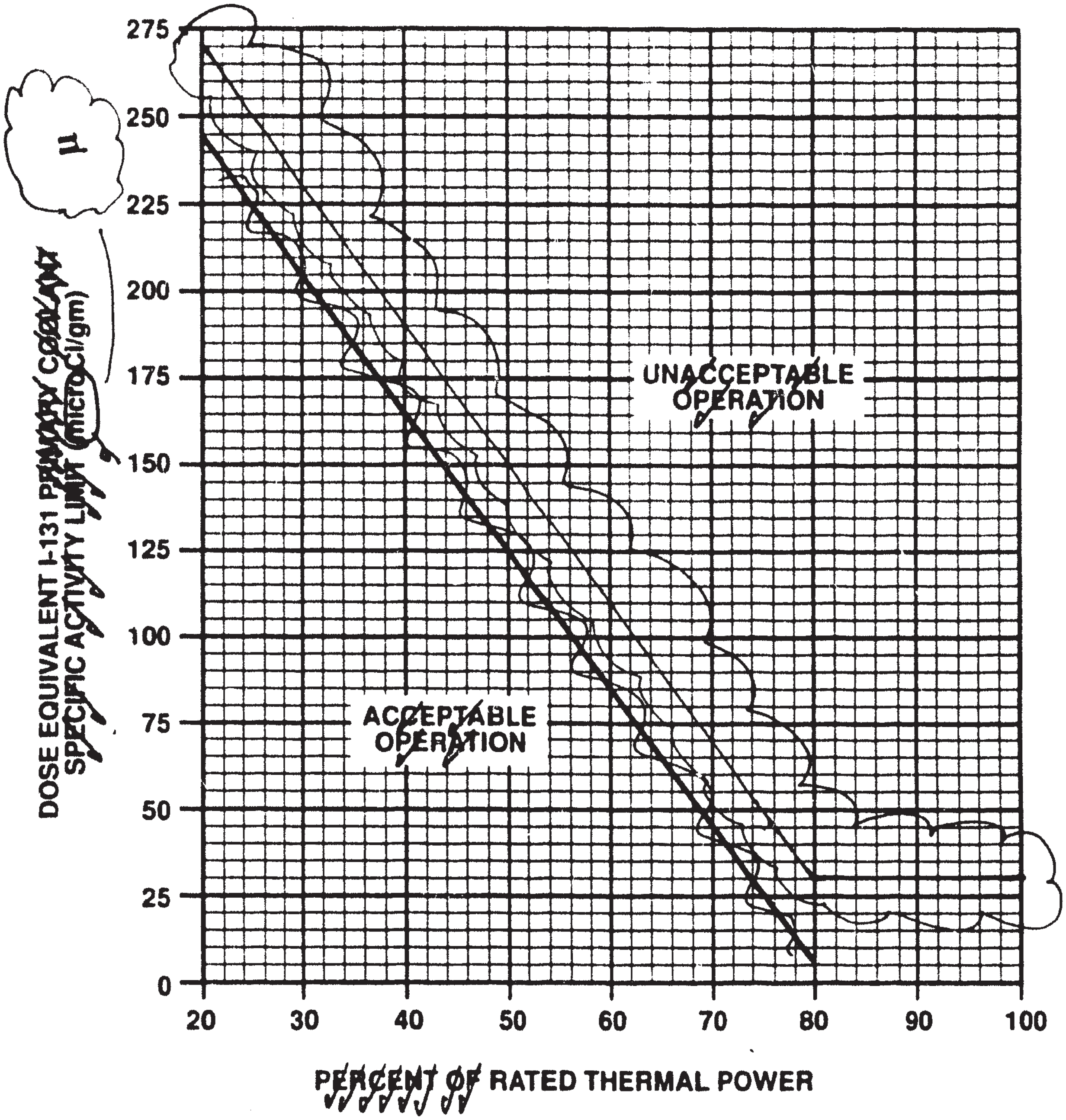

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Figure 3.4.16-1 (page 1 of 1)
DOSE EQUIVALENT I-131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity ~~$>$0.15 μCi/gram Dose Equivalent I-131.~~ e

$>$ 0.5 μCi/gm Dose Equivalent I-131

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident, or for the duration of the accident at the Low Population Zone, is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to an appropriate fraction of the 10 CFR 100 limits (i.e., a small fraction of or well within the 10 CFR 100 limits depending on the specific accident analysis) during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) or main steam line break (MSLB) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to an appropriate fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR or main steam line break (MSLB) accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting doses will not exceed an appropriate fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant ~~at the LCO limit~~ and ~~an existing~~ reactor coolant steam generator (SG) tube leakage ~~rate~~ SG of ~~150 gpd per SG~~. The ~~main steam line break (~~MSLB~~)~~ analysis assumes a steam generator tube

a bounding

at 1.0 µCi/gm

(continued)

1 gpm total for three SGs.

APPLICABLE SAFETY ANALYSES (continued)

leakage of ~~23.8 gpm~~ in the faulted loop, and ~~0.1 gpm (approximately 150 gpd)~~ in each of the intact loops (total leakage of ~~24 gpm~~). This analysis resulted in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines using ~~Regulatory Guide 1.109~~ Dose Conversion Factors (DCFs). The initial RCS specific activity assumed was ~~0.15 micro Ci/gm Dose Equivalent~~ I-131 with an iodine spike. The safety analysis assumes for both the SGTR and MSLB the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.16, "Secondary Specific Activity."

ICRP 30

1.0 μCi/gm DOSE EQUIVALENT

¶

These values bound the Technical Specifications values.

The analysis for the MSLB accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

1.0

The SGTR analysis assumes an RCS coolant activity of ~~0.5~~ μCi/gm DOSE EQUIVALENT I-131. The MSLB analysis considers two cases of reactor coolant specific activity. One case assumes specific activity at ~~0.15~~ μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the I-131 activity release rate into the reactor coolant by a factor of 500 immediately after the accident. The second case assumes the initial reactor coolant iodine activity at ~~9.0~~ μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of 100/Ē μCi/gm for gross specific activity.

1.0

60

These values bound the Technical Specifications values.

The SGTR analysis also assumes a loss of offsite power coincident with a reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

The main steam line break (MSLB) analysis assumes a double-ended guillotine break of a main steamline outside of containment. The affected steam generator will rapidly depressurize and release both the radionuclides initially contained in the secondary coolant, and the primary coolant activity transferred via SG tube leakage, directly to

(continued)

APPLICABLE SAFETY ANALYSES (continued)

the outside atmosphere. A portion of the iodine activity initially contained in the intact SGs and noble gas activity due to SG tube leakage is released to the atmosphere through either the SG atmospheric relief valves (ARVs) or the SG safety relief valves.

The safety analysis assumes an accident initiated iodine spike and shows the radiological consequences of a MSLB accident are within a small fraction of the Reference 1 dose guideline limits.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1, in the applicable specification, for more than 48 hours. The MSLB safety analysis has concurrent and pre-accident iodine spiking levels up to 60.0 μCi/gm ~~0.0 μCi/gm~~ DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a MSLB accident occurring during the established 48 hour time limit. The occurrence of a MSLB accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

The limits on RCS specific activity are also used for establishing standardization in plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement.

LCO

The specific iodine activity is limited to 0.5 μCi/gm DOSE EQUIVALENT I-131 for the SGTR analysis and ~~0.15 μCi/gm DOSE EQUIVALENT I-131~~ for the MSLB analysis, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the thyroid dose to an individual during the Design Basis Accident (DBA) will be an appropriate fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose.

(continued)

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed; and

d. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day for the first 24 hours and 0.075% thereafter (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from a LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.15% per day in the safety analysis at P_a = ~~43 psig~~ 43.8 psig e (Ref. 3).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of the NRC Policy Statement.

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B, as the maximum allowable containment leakage rate at the calculated peak containment internal pressure, P_a = ~~(43 psig)~~, following a LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of the NRC Policy Statement.

43.8 psig

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and

(continued)

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. The worst case SLB generates larger mass and energy release than the worst case LOCA. Thus, the SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 17.7 psia (3.0 psig). This resulted in a maximum peak pressure from a SLB of ~~52.4 psig~~ 52.0 psig. The containment analysis (Ref. 1) shows the maximum peak calculated containment pressure, P_a, resulting from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA, ~~43.0 psig,~~ 43.8 psig, does not exceed the containment design pressure, 54 psig.

The containment was also designed for an external pressure load equivalent to –3.0 psig. The inadvertent actuation of the Containment

(continued)

APPLICABLE SAFETY ANALYSES (continued)

pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

367°F

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 127°F. This resulted in a maximum containment air temperature of ~~383°F~~. The design air temperature is 378°F.

The temperature limit is used to establish the environmental qualification operating envelope for containment. ~~The maximum peak containment air temperature was calculated to exceed the containment design air temperature for only a few seconds during the transient.~~ The basis of the containment design air temperature~~, however,~~ is to ensure the performance of safety-related equipment inside containment (Ref. 2). Thermal analyses showed that ~~the time interval during which~~ the containment air temperature ~~exceeded the containment design air temperature was short enough that the equipment surface temperatures~~ remained below the equipment design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System.

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a SLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of the NRC Policy Statement.

BACKGROUND

Containment Cooling System (continued)

ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, unless an LOSP signal is present, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If an LOSP signal is present, only the two fans selected (one per train) will receive an auto-start signal and will start in slow speed. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. In addition, if temperature at the cooler discharge reaches 135°F, fusible links holding dropout plates will open and the fan discharge will no longer be directed through the common discharge header. This function helps to protect the fans in a post-accident environment by reducing the back pressure on the fans. The temperature of the SW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

52.0 psig

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is ~~52.4 psig~~ (experienced during an SLB). The analysis shows that the peak containment temperature is ~~383°F~~ (experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.)

367°F

(continued)

B 3.7.16 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

0.5 μCi/gm

This limit is lower than the activity value that might be expected from a ~~420 (Unit 1) or~~ 450 ~~(Unit 2)~~ gallons per day tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of ~~0.15 μCi/gm~~ (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours).

With the specified activity limit, the resultant 2 hour thyroid dose to a person at the site boundary would be within the limits of 10 CFR 20.1-20.601 if the main steam safety valves (MSSVs) and Atmospheric Relief Valves (ARVs) are open for 2 hours following a trip from full power.

Operating at the allowable limits results in a 2 hour site boundary exposure well within the 10 CFR 100 (Ref. 1) limits.

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological

(continued)

5.5.8 Inservice Testing Program (continued)

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.9 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies.

5.5.9.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

[Specification 5.5.9 is not required to be performed on the replacement steam generators during the shutdown when the steam generators are replaced.]

(continued)

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.9.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.9-1.

5.5.9.2 Steam Generator Tube* Sample Selection and Inspection

5.5.9.2.1 The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Tables 5.5.9-2 ~~and 5.5.9-3~~. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.9.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.9.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. (For Unit 2 only: Selection of tubes to be inspected is not affected by the F* designation.) When applying the exceptions of 5.5.9.2.a through 5.5.9.2.c, previous defects or imperfections in the area repaired by sleeving are not considered an area requiring reinspection. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

* When referring to a steam generator tube, the sleeve shall be considered a part of the tube if the tube has been repaired per Specification 5.5.9.4.a.9.

(continued)

5.5.9.2.1 (continued)

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 5.5.9.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube ~~or sleeve~~ inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

4. Indications left in service as a result of application of the tube support plate voltage-based repair criteria shall be inspected by bobbin coil probe during all future refueling outages.

c. The tubes selected as the second and third samples (if required by Tables 5.5.9-2 ~~and 5.5.9-3~~) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

(continued)

5.5.9.2.1 (continued)

d. Implementation of the steam generator tube/tube support plate repair criteria requires a 100 percent bobbin coil inspection for hot-leg and cold-leg tube support plate intersections down to the lowest cold-leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes or sleeves must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

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5.5.9.2.2 (For Unit 2 only) Steam Generator F* Tube Inspection

In addition to the minimum sample size as determined by Specification 5.5.9.2.1, all F* tubes will be inspected within the tubesheet region. The results of this inspection will not be a cause for additional inspections per Tables 5.5.9-2 and 5.5.9-3.

5.5.9.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table~~s~~ 5.5.9-2 ~~and 5.5.9-3~~ at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.9.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table~~s~~ 5.5.9-2 ~~and 5.5.9-3~~ during the shutdown subsequent to any of the following conditions:

(continued)

5.5.9.3 Inspection Frequencies (continued)

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.13.

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

5.5.9.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube ~~or sleeve~~ from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube ~~or sleeve.~~

3. Degraded Tube means a tube, ~~including the sleeve if the tube has been repaired,~~ that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube ~~or sleeve~~ wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging ~~or repair~~ limit. A tube ~~or sleeve~~ containing a defect is defective.

(continued)

5.5.9.4 Acceptance Criteria (continued)

6. Plugging or Repair Limit means the imperfection depth at or beyond which the tube shall be ~~repaired (i.e., sleeved) or~~ removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness. (For Unit 2 only: This definition does not apply for tubes that meet the F* criteria.) For a tube that has been sleeved with a mechanical joint sleeve, through wall penetration of greater than or equal to 31% of sleeve nominal wall thickness in the sleeve requires the tube to be removed from service by plugging. For a tube that has been sleeved with a welded joint sleeve, through wall penetration greater than or equal to 24% of sleeve nominal wall thickness in the sleeve between the weld joints requires the tube to be removed from service by plugging. This definition does not apply to tube support plate intersections for which the voltage-based repair criteria are being applied. Refer to 5.5.9.4.a.14 for the repair limit applicable to these intersections. (For Unit 2 only: For a tube with an imperfection or flaw in the tube sheet below the lower joint for an installed elevated laser welded sleeve, no repair or plugging is required provided the installed sleeve meets all sleeved tube inspection requirements.)

7. Unserviceable describes the condition of a tube ~~or sleeve~~ if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.9.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg. (For Unit 2 only: For a tube with a tube sheet sleeve installed, the point of entry is the bottom of the tube sheet sleeve below the lower sleeve joint.) For a tube that has been repaired by sleeving, the tube inspection should include the sleeved portion of the tube.

(continued)

5.5.9.4 Acceptance Criteria (continued)

9. Tube repair refers to mechanical sleeving, as described by Westinghouse report WCAP-11178, Rev. 1, or laser welded sleeving, as described by Westinghouse reports WCAP-13088, Revision 4, and WCAP-14740 dated January 1997, which is used to maintain a tube in service or return a tube to service. This includes the removal of plugs that were installed as a corrective or preventive measure.

9. ~~10.~~ Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed ~~after the field hydrostatic test and prior to initial POWER OPERATOIN~~ using the equipment and techniques expected to be used during subsequent inservice inspections.

11. (For Unit 2 only) F* Distance is the distance of the expanded portion of a tube which provides a sufficient length of undegraded tube expansion to resist pullout of the tube from the tubesheet. The F* distance is equal to 1.60 inches plus allowance for eddy current uncertainty measurement and is measured down from the top of the tube sheet or the bottom of the roll transition, whichever is lower in elevation. The allowance for eddy current uncertainty is documented in the steam generator eddy current inspection procedure.

12. (For Unit 2 only) F* Tube is a tube:

   a. with degradation equal to or greater than 40% below the F* distance, and

   b. which has no indication of imperfections greater than or equal to 20% of nominal wall thickness within the F* distance, and

   c. that remains inservice.

(continued)

5.5.9.4 Acceptance Criteria (continued)

13. (For Unit 2 only) Tube Expansion is that portion of a tube which has been increased in diameter by a rolling process such that no crevice exists between the outside diameter of the tube and the hole in the tubesheet. Tube expansion also refers to that portion of a sleeve which has been increased in diameter by a rolling process such that no crevice exists between the outside diameter of the sleeve and the parent steam generator tube.

14. Tube Support Plate Repair Limit is used for the disposition of an alloy 600 steam generator tube for continued service that is experiencing predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates. At tube support plate intersections, the repair limit is based on maintaining steam generator tube serviceability as described below:

    a. Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with bobbin voltage less than or equal to the lower voltage repair limit (2.0 volts), will be allowed to remain in service.

    b. Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than the lower voltage repair limit (2.0 volts), will be repaired or plugged except as noted in 5.5.9.4.a.14.c below.

(continued)

5.5.9.4 Acceptance Criteria (continued)

c. Steam generator tubes, with indications of potential degradation attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than the lower voltage repair limit (2.0 volts), but less than or equal to the upper voltage repair limit*, may remain in service if a rotating probe inspection does not detect degradation. Steam generator tubes, with indications of outside diameter stress corrosion cracking degradation with a bobbin voltage greater than the upper voltage repair limit*, will be plugged or repaired.

d. If an unscheduled mid-cycle inspection is performed, the following mid-cycle repair limits apply instead of the limits identified in 5.5.9.4.a.14.a, 5.5.9.4.a.14.b, and 5.5.9.4.a.14.c.

$$V_{MURL} = \frac{V_{SL}}{1.0 + NDE + Gr\,\frac{[CL - \Delta t]}{CL}}$$

$$V_{MLRL} = V_{MURL} - [V_{URL} - V_{LRL}]\,\frac{[CL - \Delta t]}{CL}$$

where:

V_{URL}	=	upper voltage repair limit
V_{LRL}	=	lower voltage repair limit
V_{MURL}	=	mid-cycle upper voltage repair limit based on time into cycle
V_{MLRL}	=	mid-cycle lower voltage repair limit based on V_{MURL} and time into cycle

* The upper voltage repair limit is calculated according to the methodology in Generic Letter 95-05 as supplemented.

(continued)

5.5.9.4 Acceptance Criteria (continued)

Δt	=	length of time since last scheduled inspection during which V_{URL} and V_{LRL} were implemented
CL	=	cycle length (the time between two scheduled steam generator inspections)
V_{SL}	=	structural limit voltage
Gr	=	average growth rate per cycle length
NDE	=	95-percent cumulative probability allowance for nondestructive examination uncertainty (i.e., a value of 20 percent has been approved by NRC)

Implementation of these mid-cycle repair limits should follow the same approach as in TS 5.5.9.4.a.14.a, 5.5.9.4.a.14.b, and 5.5.9.4.a.14.c.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug ~~or repair of~~ all tubes exceeding the plugging ~~or repair~~ limit) required by Table~~s~~ 5.5.9-2 ~~and 5.5.9-3~~.

Table 5.5.9-2
Steam Generator Tube Inspection

Sample Size	1st Sample Inspection: Result	1st Sample Inspection: Action Required	2nd Sample Inspection: Result	2nd Sample Inspection: Action Required	3rd Sample Inspection: Result	3rd Sample Inspection: Action Required
A minimum of S Tubes per S.G.	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug ~~or repair~~ defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug ~~or repair~~ defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug ~~or repair~~ defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., plug ~~or repair~~ defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to 10 CFR 50.73	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s C-2 but no additional S.G.s are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug ~~or repair~~ defective tubes. Notification to NRC pursuant to 10 CFR 50.73	N/A	N/A

$S = \frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

(For Unit 2 only — NOTE: F* tubes do not have to be plugged or repaired.)

Table 5.5.9-3
Steam Generator Repaired Tube Inspection

	1st Sample Inspection		2nd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required
A minimum of 20% of repaired tubes (1)(2)	C-1	None	N/A	N/A
	C-2	Plug or repair defective repaired tubes and inspect 100% of the repaired tubes in this steam generator	C-1	None
			C-2	Plug or repair defective repaired tubes.
			C-3	Perform action for C-3 result of first sample.
	C-3	Inspect all repaired tubes in this steam generator, plug or repair defective tubes and inspect 20% of the repaired tubes in each steam generator Notification to NRC pursuant to 10CFR50.72(b)(2).	All other steam generators are C-1.	None
			Some steam generators C-2 but no additional steam generators are C-3.	Perform action for C-2 result of first sample.
			Additional steam generator is C-3.	Inspect all repaired tubes in each steam generator and plug or repair defective tubes. Notification to NRC pursuant to 10CFR50.72(b)(2).

(1) Each repair method is considered a separate population for determination of scope expansion.
(2) The inspection of repaired tubes may be performed on tubes from 1 to 3 steam generators based on outage plans.

5.5.15 Safety Function Determination Program (SFDP) (continued)

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Main Steamline Inspection Program

The three main steamlines from the rigid anchor points of the containment penetrations downstream to and including the main steam header shall be inspected. The extent of the inservice examinations completed during each inspection interval (IWA 2400, ASME Code, 1974 Edition, Section XI) shall provide 100 percent volumetric examination of circumferential and longitudinal pipe welds to the extent practical. The areas subject to examination are those defined in accordance with examination category C-G for Class 2 piping welds in Table IWC-2520.

5.5.17 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of containment as required by 10 CFR 50.54 (o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is ~~43 psig.~~

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

43.8 psig

(continued)

5.6.7 EDG Failure Report

If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures shall be reported within 30 days. Reports on EDG failures shall include a description of the failures, underlying causes, and corrective actions taken per the Emergency Diesel Generator Reliability Monitoring Program.

5.6.8 PAM Report

When a report is required by Condition B or G of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.9 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Pre-stressed Concrete Containment Tendon Surveillance Program shall be reported to the NRC within 30 days. The report shall include a description of the tendon condition, the condition of the concrete (especially at tendon anchorages), the inspection procedures, the tolerances on cracking, and the corrective action taken.

Inspection

5.6.10 Steam Generator Tube ~~Inspector~~ Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged~~, repaired (for Unit 2 only: or designated F*),~~ in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging ~~or repair~~ effort.

b. The complete results of the steam generator tube ~~and sleeve~~ inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

(continued)

Inspection

5.6.10 Steam Generator Tube ~~Inspector~~ Report (continued)

1.. Number and extent of tubes ~~and sleeves~~ inspected.

Reportable Event

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged ~~or repaired.~~

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a ~~REPORTABLE EVENT and~~ shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. The written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

d. For implementation of the voltage-based repair criteria to tube support plate intersections, notify the NRC staff prior to returning the steam generators to service (Mode 4) should any of the following conditions arise:

1. If estimated leakage based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds the leak limit (detemined from the licensing basis dose calculation for the postulated main steam line break) for the next operating cycle.

2. If circumferential crack-like indications are detected at the tube support plate intersections.

3. If indications are identified that extend beyond the confines of the tube support plate.

4. If indications are identified at the tube support plate elevations that are attributable to primary water stress corrosion cracking.

5. If the calculated conditional burst probability based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds 1×10^{-2}, notify the NRC and provide an assessment of the safety significance of the occurrence.

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

Unit 2

Typed Pages

Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
11. Reactor Coolant Pump (RCP) Breaker Position						
a. Single Loop	1[(g)]	1 per RCP	N	SR 3.3.1.12	NA	NA
b. Two Loops	1[(h)]	1 per RCP	M	SR 3.3.1.12	NA	NA
12. Undervoltage RCPs	1[(f)]	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 2640 V	≥ 2680 V
13. Underfrequency RCPs	1[(f)]	2 per bus	M	SR 3.3.1.6 SR 3.3.1.10	≥ 56.9 Hz	≥ 57 Hz
14. Steam Generator (SG) Water Level — Low Low	1,2	3 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.14	≥ 27.6%	≥ 28%

(f) Above the P-7 (Low Power Reactor Trips Block) interlock.

(g) Above the P-8 (Power Range Neutron Flux) interlock.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

Table 3.3.2-1 (page 4 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
5. Turbine Trip and Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1,2(g)	2 trains	H	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
b. SG Water Level - High High (P-14)	1,2(g)	3 per SG	I	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	≤ 82.4%	≤ 82%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. Auxiliary Feedwater						
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.8	NA	NA
b. SG Water Level - Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.9	≥ 27.6%	≥ 28%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
d. Undervoltage Reactor Coolant Pump	1,2	2 per bus	I	SR 3.3.2.5 SR 3.3.2.7	≥ 2640 volts	≥ 2680 volts
e. Trip of all Main Feedwater Pumps	1	2 per pump	J	SR 3.3.2.10	NA	NA
7. ESFAS Interlocks						
a. Reactor Trip, P-4	1,2,3	1 per train, 2 trains	F	SR 3.3.2.6	NA	NA
b. Pressurizer Pressure, P-11	1,2,3	3	K	SR 3.3.2.7	≤ 2003 psig	≤ 2000 psig
c. T_{avg} - Low Low, P-12 (Decreasing) (Increasing)	1,2,3	1 per loop	K	SR 3.3.2.7	≥ 542.6°F ≤ 545.4°F	≥ 543°F ≤ 545°F

(g) Except when all Main Feedwater lines are isolated by either a Main Feedwater Stop Valve or an MFRV and associated bypass valve or by a closed manual valve.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 75% (wide range) for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

ACTIONS

C.1 and C.2 (continued)

inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened.

The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ≥ 75% for required RCS loops. If the SG

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

secondary side wide range water level is < 75%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES

None.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required RHR loop inoperable. <u>AND</u> Two required RCS loops inoperable.	B.1	Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. <u>OR</u> No RCS or RHR loop in operation.	C.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	<u>AND</u>		
	C.2	Initiate action to restore one loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water levels are ≥ 75% (wide range) for required RCS loops.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side wide range water level is ≥ 75%. If the SG secondary side wide range water level is < 75%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.

3.4.7 RCS Loops — MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be ≥ 75% (wide range).

---NOTES---

1. The RHR pump of the loop in operation may not be in operation for ≤ 2 hours per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ 325°F unless:

   a. The secondary side water temperature of each SG is < 50°F above each of the RCS cold leg temperatures; or

   b. The pressurizer water volume is less than 770 cubic feet (24% of wide range, cold, pressurizer level indication).

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

5. The number of operating Reactor Coolant Pumps is limited to one at RCS temperatures < 110°F with the exception that a second pump may be started for the purpose of maintaining continuous flow while taking the operating pump out of service.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side water levels not within limits.	A.1 Initiate action to restore a second RHR loop to OPERABLE status. OR A.2 Initiate action to restore required SG secondary side water levels to within limits.	Immediately Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving a reduction of RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side water level is ≥ 75% (wide range) in required SGs.	12 hours

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation (Ref. 1) are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels ≥ 75% (wide range) to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops — MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥ 75% (wide range). One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ 75% (wide range). Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to not be in operation ≤ 2 hours per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 2 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration

(continued)

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ 75% (wide range).

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels < 75% (wide range), redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal.

The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side wide range water levels are ≥ 75% ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥ 75% (wide range) in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

3.4.13 RCS Opera..onal LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE;

d. 450 gallons per day total primary to secondary LEAKAGE through all steam generators (SGs); and

e. 150 gallons per day primary to secondary LEAKAGE through any one SG.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is typically seen as a precursor to a LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 150 gpd per SG primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The FSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via the main steam safety valves. The majority of the activity released to the atmosphere results from the tube rupture. Therefore, the 150 gpd per SG primary to secondary LEAKAGE is inconsequential.

The SLB is more limiting for primary to secondary LEAKAGE. The safety analysis for the SLB assumes 500 gpd and 470 gpd primary to secondary LEAKAGE in the ruptured and intact steam generators respectively as an initial condition. The dose consequences resulting from the SLB accident are bounded by a small fraction (i.e., 10%) of the limits defined in 10 CFR 100. The RCS specific activity assumed was a bounding value of 1.0 μCi/gm DOSE EQUIVALENT I-131, with either a pre-existing or an accident initiated iodine spike. These values bound the Technical Specifications values.

The RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher

(continued)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. DOSE EQUIVALENT I-131 > 0.5 μCi/gm.	------------------Note------------------ LCO 3.0.4 is not applicable. --		
	A.1	Verify DOSE EQUIVALENT I-131 within the acceptable region of Figure 3.4.16-1.	Once per 4 hours
	AND		
	A.2	Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit.	B.1	Be in MODE 3 with T_{avg} < 500°F.	6 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 in the unacceptable region of Figure 3.4.16-1.	C.1 Be in MODE 3 with $T_{avg} < 500°F$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity $\leq 100/\bar{E}$ μCi/gm.	7 days
SR 3.4.16.2	------------------------------NOTE------------------------------ Only required to be performed in MODE 1. -- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 0.5 μCi/gm.	14 days AND Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

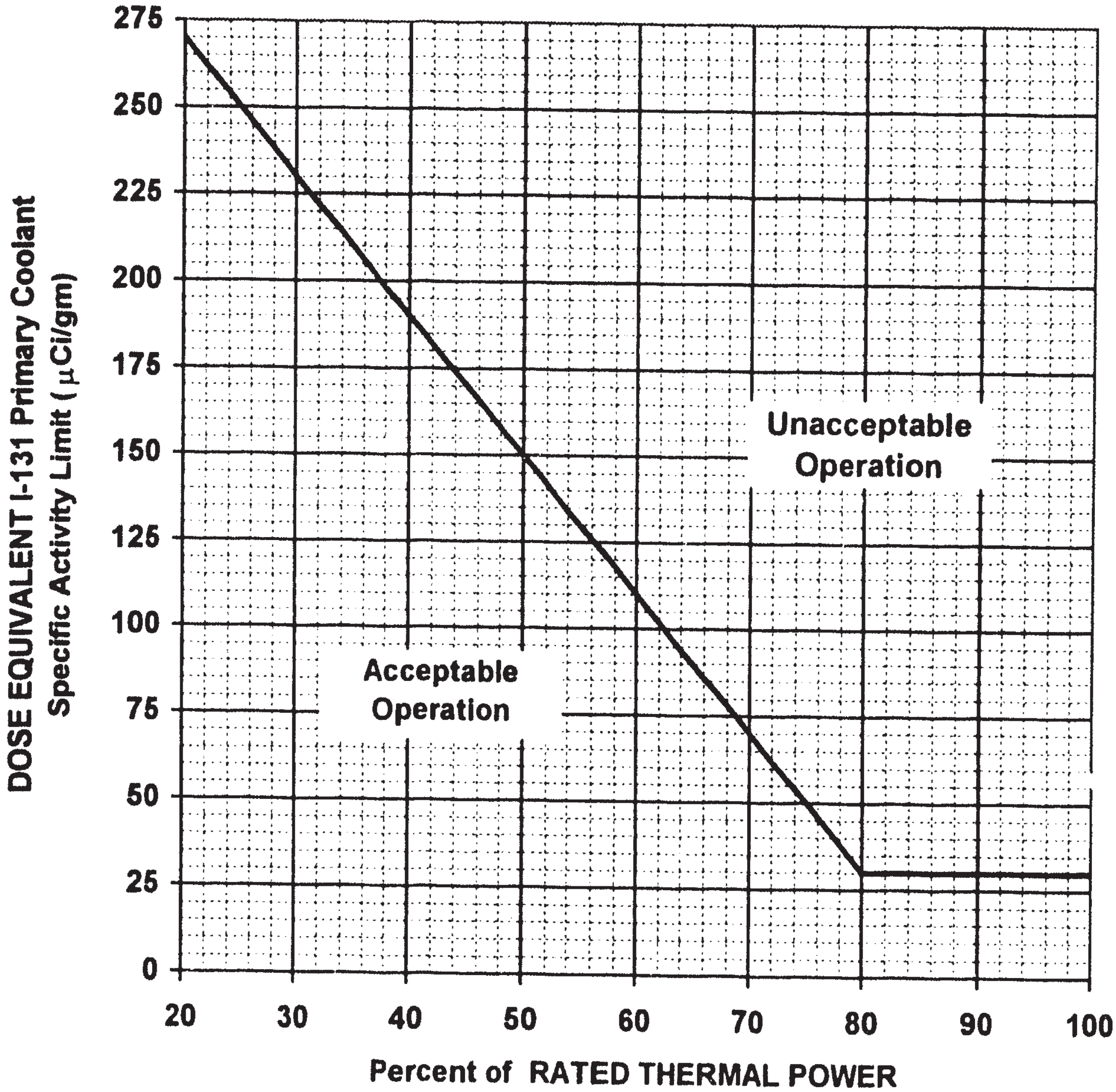

Figure 3.4.16-1 (page 1 of 1)

DOSE EQUIVALENT I-131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity > 0.5 μCi/gm DOSE EQUIVALENT I-131

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident, or for the duration of the accident at the Low Population Zone, is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to an appropriate fraction of the 10 CFR 100 limits (i.e., a small fraction of or well within the 10 CFR 100 limits depending on the specific accident analysis) during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) or main steam line break (MSLB) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to an appropriate fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR or main steam line break (MSLB) accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSIS

The LCO limits on the specific activity of the reactor coolant ensures that the resulting doses will not exceed an appropriate fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at 1.0 μCi/gm and a bounding reactor coolant steam generator (SG) tube leakage of 1 gpm total for three SGs. The MSLB analysis assumes a steam generator tube leakage of 500 gpd in the faulted loop and 470 gpd in each of the intact loops for a total leakage of 1440 gpd.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

This analysis resulted in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 100 guidelines using ICRP 30 Dose Conversion Factors (DCFs). The initial RCS specific activity assumed was 1.0 μCi/gm DOSE EQUIVALENT I-131 with an iodine spike. These values bound the Technical Specifications values. The safety analysis assumes for both the SGTR and MSLB the specific activity of the secondary coolant as its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.16, "Secondary Specific Activity."

The analysis for the MSLB accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The SGTR analysis assumes a RCS coolant activity of 1.0 μCi/gm DOSE EQUIVALENT I-131. The MSBL analysis considers two cases of reactor coolant specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the I-131 activity release rate into the reactor coolant by a factor of 500 immediately after the accident. The second case assumes the initial reactor coolant iodine activity at 60 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. These values bound the Technical Specifications values. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of $100/\bar{E}$ μCi/gm for gross specific activity.

The SGTR analysis also assumes a loss of offsite power coincident with a reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

The main steam line break (MSLB) analysis assumes a double-ended guillotine break of a main steamline outside of containment. The affected steam generator will rapidly depressurize and release both the radionuclides initially contained in the secondary coolant, and the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

primary coolant activity transferred via SG tube leakage, directly to the outside atmosphere. A portion of the iodine activity initially contained in the intact SGs and noble gas activity due to SG tube leakage is released to the atmosphere through either the SG atmospheric relief valves (ARVs) or the SG safety relief valves.

The safety analysis assumes an accident initiated iodine spike and shows the radiological consequences of a MSLB accident are within a small fraction of the Reference 1 dose guideline limits.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1, in the applicable specification, for more than 48 hours. The MSLB safety analysis has concurrent and pre-accident iodine spiking levels up to 60.0 μCi/gm DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a MSLB accident occurring during the established 48 hour time limit. The occurrence of a MSLB accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

The limits on RCS specific activity are also used for establishing standardization in plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement.

LCO

The specific iodine activity is limited to 0.5 μCi/gm DOSE EQUIVALENT I-131 for the SGTR analysis and for the MSLB analysis, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the thyroid dose to an individual during the Design Basis Accident (DBA) will be an appropriate fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose.

(continued)

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed; and

d. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day for the first 24 hours and 0.075% thereafter (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from a LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.15% per day in the safety analysis at P_a = 43.8 psig (Ref. 3).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of the NRC Policy Statement.

BASES

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B, as the maximum allowable containment leakage rate at the calculated peak containment internal pressure, P_a = 43.8 psig, following a LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of the NRC Policy Statement.

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. The worst case SLB generates larger mass and energy release than the worst case LOCA. Thus, the SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 17.7 psia (3.0 psig). This resulted in a maximum peak pressure from a SLB of 52.0 psig. The containment analysis (Ref. 1) shows the maximum peak calculated containment pressure, P_a, resulting from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA, 43.8 psig, does not exceed the containment design pressure, 54 psig.

The containment was also designed for an external pressure load equivalent to –3.0 psig. The inadvertent actuation of the Containment

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 127°F. This resulted in a maximum containment air temperature of 367°F. The design air temperature is 378°F.

The temperature limit is used to establish the environmental qualification operating envelope for containment. The basis of the containment design air temperature is to ensure the performance of safety-related equipment inside containment (Ref. 2). Thermal analyses showed that the containment air temperature remained below the equipment design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System.

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a SLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of the NRC Policy Statement.

BASES

BACKGROUND

Containment Cooling System (continued)

ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, unless an LOSP signal is present, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If an LOSP signal is present, only the two fans selected (one per train) will receive an auto-start signal and will start in slow speed. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. In addition, if temperature at the cooler discharge reaches 135°F, fusible links holding dropout plates will open and the fan discharge will no longer be directed through the common discharge header. This function helps to protect the fans in a post-accident environment by reducing the back pressure on the fans. The temperature of the SW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 52.0 psig (experienced during an SLB). The analysis shows that the peak containment temperature is 367°F (experienced during a SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.)

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.16 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 450 gallons per day tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 0.5 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives (i.e., < 20 hours).

With the specified activity limit, the resultant 2 hour thyroid dose to a person at the site boundary would be within the limits of 10 CFR 20.1-20.601 if the main steam safety valves (MSSVs) and Atmospheric Relief Valves (ARVs) are open for 2 hours following a trip from full power.

Operating at the allowable limits results in a 2 hour site boundary exposure well within the 10 CFR 100 (Ref. 1) limits.

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological

(continued)

5.5 Programs and Manuals

5.5.8 Inservice Testing Program (continued)

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.9 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies. [Specification 5.5.9 is not required to be performed on the replacement steam generators during the shutdown when the steam generators are replaced.]

5.5.9.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.9.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.9-1.

5.5.9.2 Steam Generator Tube Sample Selection and Inspection

5.5.9.2.1 The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5.9-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.9.3, and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.9.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 5.5.9.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

(continued)

5.5 Programs and Manuals

5.5.9.2.1 (continued)

c. The tubes selected as the second and third samples (if required by Table 5.5.9-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

5.5.9.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 5.5.9-2 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.9.3.a; the interval may then be extended to a maximum of once per 40 months.

(continued)

5.5 Programs and Manuals

5.5.9.3 Inspection Frequencies (continued)

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.9-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.13.

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

5.5.9.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. Degraded Tube means a tube that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

(continued)

5.5 Programs and Manuals

5.5.9.4 Acceptance Criteria (continued)

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Plugging or Repair Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.9.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.

9. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug all tubes exceeding the plugging limit) required by Table 5.5.9-2.

Table 5.5.9-1

No of Steam Generators per Unit	Three
First Inservice Inspection	Two
Second Subsequent Inservice Inspections	One*

* The other steam generator not inspected during the first inservice inspection shall be reinspected. The third and subsequent inspections may be limited to one steam generator on a rotating schedule encompassing 3 N% of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the same sequence shall be modified to inspect the most severe conditions.

Table 5.5.9-2
Steam Generator Tube Inspection

	1st Sample Inspection		2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G.	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., plug defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to 10 CFR 50.73	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s C-2 but no additional S.G.s are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug defective tubes. Notification to NRC pursuant to 10 CFR 50.73	N/A	N/A

$S = \frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

5.5 Programs and Manuals

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the condenser hotwells for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in, and in accordance with, ASME N510-1989. The FNP Final Safety Analysis Report identifies the relevant surveillance testing requirements.

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 0.5% when tested in accordance with ASME N510-1989 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate (CFM)
CREFS Recirculation	2,000
CREFS Filtration	1,000
CREFS Pressurization	300
PRF Post LOCA Mode	5,000

(continued)

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 0.5% when tested in accordance ASME N510-1989 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate (CFM)
CREFS Recirculation	2,000
CREFS Filtration	1,000
CREFS Pressurization	300
PRF Post LOCA Mode	5,000

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in ASME N510-1989, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of ≤ 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation System	Penetration	RH
CREFS Recirculation	2.5%	70%
CREFS Filtration	2.5%	70%
CREFS Pressurization	0.5%	70%
PRF Post LOCA Mode	10%	95%

NOTE: CREFS Pressurization methyl iodide penetration limit is based on a 6-inch bed depth.

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters and the charcoal adsorbers is less than the value specified below when tested in accordance with ASME N510-1989 at the system flowrate specified below ± 10%.

ESF Ventilation System	Delta P (in. water gauge)	Flowrate (CFM)
CREFS Recirculation	2.3	2,000
CREFS Filtration	2.9	1,000
CREFS Pressurization	2.2	300
PRF Post LOCA Mode	2.6	5,000

(continued)

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

e. Demonstrate that the heaters for the CREFS Pressurization System dissipate the value specified below ± 10% when tested in accordance with ASME N510-1989.

ESF Ventilation System	Wattage (kW)
CREFS Pressurization	7.5

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Waste Gas System, the quantity of radioactivity contained in gas storage tanks, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Waste Gas System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design;

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas storage tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than 10 curies.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5 Programs and Manuals

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to the emergency diesel generator storage tanks by determining that the fuel oil has:

    1. an API gravity or an absolute specific gravity within limits,

    2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

    3. a clear and bright appearance.

b. Fuel oil stored in the emergency diesel generator storage tanks is within limits by verifying that a sample of diesel fuel oil from the storage tank, obtained in accordance with ASTM-D270-65, is within the acceptable limits specified in Table 1 of ASTM D975-74 when checked for viscosity, water, and sediment every 92 days.

c. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance test frequencies.

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

    1. a change in the TS incorporated in the license; or

    2. a change to the updated FSAR or Bases that involves an unreviewed safety question as defined in 10 CFR 50.59.

(continued)

5.5 Programs and Manuals

5.5.14 Technical Specifications (TS) Bases Control Program (continued)

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of Specification 5.5.14b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.15 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

(continued)

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Main Steamline Inspection Program

The three main steamlines from the rigid anchor points of the containment penetrations downstream to and including the main steam header shall be inspected. The extent of the inservice examinations completed during each inspection interval (IWA 2400, ASME Code, 1974 Edition, Section XI) shall provide 100 percent volumetric examination of circumferential and longitudinal pipe welds to the extent practical. The areas subject to examination are those defined in accordance with examination category C-G for Class 2 piping welds in Table IWC-2520.

5.5.17 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of containment as required by 10 CFR 50.54 (o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 43.8 psig.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

(continued)

5.5 Programs and Manuals

5.5.17 Containment Leakage Rate Testing Program (continued)

Leakage rate acceptance criteria are:

a. Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the combined Type B and C tests, and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

   1. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2. For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 10 psig.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.6 Reporting Requirements

5.6.7 EDG Failure Report

If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures shall be reported within 30 days. Reports on EDG failures shall include a description of the failures, underlying causes, and corrective actions taken per the Emergency Diesel Generator Reliability Monitoring Program.

5.6.8 PAM Report

When a report is required by Condition B or G of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.9 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Pre-stressed Concrete Containment Tendon Surveillance Program shall be reported to the NRC within 30 days. The report shall include a description of the tendon condition, the condition of the concrete (especially at tendon anchorages), the inspection procedures, the tolerances on cracking, and the corrective action taken.

5.6.10 Steam Generator Tube Inspection Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging effort.

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

(continued)

5.6.10 Steam Generator Tube Inspection Report (continued)

1. Number and extent of tubes inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a Reportable Event and shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. The written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

Attachment 3

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

Significant Hazards Evaluation

Significant Hazards Evaluation

Introduction and Background

Southern Nuclear Operating Company (SNC) has completed a comprehensive engineering review program in support of Farley Nuclear Plant (FNP) plans to replace the current Model 51 steam generators (SGs) with Westinghouse Model 54F SGs. The Model 54F SG is very similar in operating characteristics to the currently installed Model 51 SG; however, based on the review program results, Technical Specifications changes will be required. The program includes re-analysis and evaluation of all LOCA, non-LOCA, mass and energy release, containment and sub-compartment pressure and temperature responses, and dose analyses, and NSSS and BOP systems. The analyses and evaluations results demonstrate all applicable acceptance criteria continue to be met.

All major NSSS components (e.g., Reactor Vessel, Pressurizer, Reactor Coolant Pumps, etc.) have been assessed with respect to bounding conditions expected for operation with the Model 54F SG. In all cases, NSSS component operation has been found acceptable. Major systems and sub-systems (i.e., safety injection, auxiliary feedwater, residual heat removal, turbine generator, etc.) have been reviewed and acceptable performance has been verified for their normal operational functions and, as applicable, for their safety-related functions. All reactor trip and Engineered Safety Features (ESF) actuation setpoints have been assessed, and the proposed setpoint modifications will assure adequate protection is afforded for all design basis events. Control systems including rod control, pressurizer level control and SG level control have been evaluated and been found acceptable for operation with the Model 54F SG.

The FNP large break LOCA analysis recently approved for power uprate used the Westinghouse Best Estimate LOCA (BELOCA) methodology. The effects of the replacement steam generators were evaluated and, where appropriate, re-analyzed using the NRC approved Westinghouse BELOCA methodology. The results of this process showed that all 10 CFR 50.46 criteria continue to be met. The small break LOCA was re-analyzed using NRC approved methodology, and all 10 CFR 50.46 criteria continue to be met.

The technical bases for the proposed changes to the FNP Units 1 and 2 Technical Specifications are contained in WCAP-15098, "Farley Nuclear Plant Units 1 and 2 Replacement Steam Generator Program NSSS Licensing Report," and the "Farley Nuclear Plant Units 1 and 2 Steam Generator Replacement Project BOP Licensing Report."

Proposed Changes

The Reactor Trip System (RTS) and ESF Actuation System (ESFAS) setpoints and allowable values for steam generator water level low-low, reactor trip and auxiliary feedwater start, and steam generator water level high-high (P-14), turbine trip and feedwater isolation, have been modified to reflect Model 54F SG differences and supporting analytical results.

The minimum wide range (WR) level for decay heat removal will change from 74% WR to 75% WR to be consistent with the required water level for the Model 54F SG.

The RCS Operational Leakage limits for SGs for Unit 1 are adjusted to match the current limits approved for Unit 2. The basis for the changes are provided in the Bases proposed revision.

The RCS Specific Activity limit is adjusted from 0.15 to 0.5 μCi/gm. To bound the proposed Technical Specification change, the radiological analyses for steam generator replacement use a value of 1.0 μCi/gm RCS specific activity. The calculated offsite doses continue to meet the acceptance criteria of NUREG-0800. These changes are reflected in the Bases.

In the SG Tube Surveillance Program and the SG Tube Inspection Report requirements, the inspection criteria for SG tube inspections will change based on the characteristics of the new SG. This includes elimination of the voltage-based alternate repair criteria and tube repair by sleeving for Unit 1 and Unit 2, as well as the F* SG tube plugging criteria for Unit 2. For the outage in which the SG replacement occurs, a one time exemption from the inservice inspection requirements is requested since the preservice program for the new SG includes all necessary preservice testing, such as hydrostatic pressure testing and eddy current baseline examination.

In the SG Tube Surveillance Program acceptance criteria for preservice inspection, the restriction that the preservice inspection be performed after the field hydrostatic pressure test and prior to power operation is being removed. This proposed change only affects the schedule for when the preservice tubing inspection is performed.

The Containment Systems Bases and Containment Leakage Testing Program are revised to reflect the change in the LOCA analyses peak calculated containment internal pressure (P_a) from 43 to 43.8 psig.

The Containment Systems Bases are also revised to reflect the decreases in the MSLB analyses peak calculated containment internal pressure from 52.4 to 52.0 psig and peak calculated containment internal temperature from 383 to 367°F.

Additional minor editorial, typographical and format changes to the Technical Specifications, Bases and Programs sections are identified in the Technical Specifications, Bases and Programs sections mark-ups.

The following 3 groups of proposed changes will each be evaluated with respect to the criteria of 10 CFR 50.92. Listed below are the groupings.

I. Allowable Values and Trip Setpoints for Reactor Trip System and Engineered Safety Feature Actuation System

II. RCS Leakage Limits and Steam Generator Inspections

III. Analyses Limits for RCS and Containment

10 CFR 50.92 Evaluations

I. Allowable Values and Trip Setpoints for Reactor Trip System and Engineered Safety Feature Actuation System

TS or Bases	Title	Function / Description
Table 3.3.1-1	Reactor Trip System Instrumentation	No. 14. Steam Generator (SG) Water Level – Low Low Allowable ≥ 27.6 % Trip ≥ 28.0 %
Table 3.3.2-1	Engineered Safety Feature Actuation System Instrumentation	No. 5. Turbine Trip and Feedwater Isolation b. SG Water Level – High High (P-14) Allowable ≤ 82.4 % Trip ≤ 82.0 % No. 6. Auxiliary Feedwater b. SG Water Level – Low Low Allowable ≥ 27.6 % Trip ≥ 28.0 %

The proposed changes to RTS and ESFAS trip setpoints and allowable values have resulted from the design differences between the Westinghouse Model 51 and Model 54F SGs and the analyses performed to support FNP operation with the Model 54F SG. These analyses included feedline break, loss of load, loss of ac power, loss of normal feedwater, and mass and energy releases. The results of these analyses demonstrate that, since all acceptance criteria continue to be met, the proposed values are acceptable. Setpoint uncertainty calculations confirm the acceptability of the setpoints. The allowable value changes reflect the results of updated setpoint calculations based on Model 54F SG process measurement uncertainties and FNP specific uncertainties, calibration practices, calibration equipment, installed hardware and procedures.

Additional minor editorial, typographical and format changes to the Technical Specifications, Bases and Programs sections are identified in the Technical Specifications, Bases and Programs sections mark-ups.

Based on the analyses and evaluations performed for the SG replacement, the following conclusions can be reached with respect to 10 CFR 50.92.

1. The proposed changes to the SG Water Level High-High and Low-Low trip setpoints and allowable values do not significantly increase the probability or consequences of an accident previously evaluated in the FSAR. The comprehensive engineering review effort performed to support SG replacement has included evaluations or re-analysis of all accident analyses including all dose related events. Setpoint calculations have verified acceptability of the proposed setpoint and allowable value changes. All systems will function as designed, and all performance requirements on these systems have been verified to be acceptable. Neither the setpoints nor the allowable values initiate any accident; therefore, the probability of an accident has not been increased. All dose consequences have been analyzed or evaluated with respect to these proposed changes, and all acceptance criteria continue to be met. Therefore, these changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. The proposed setpoint and allowable value changes do not create the possibility of a new or different kind of accident than any accident already evaluated in the FSAR. No new accident scenarios, failure mechanisms or limiting single failures are introduced as a result of the proposed changes. The proposed technical specification changes have no adverse effects on any safety-related system and do not challenge the performance or integrity of any safety-related system. The specified trip setpoints associated with the respective RTS and ESFAS functions ensure all accident analyses criteria continue to be met. Therefore, these changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. The proposed technical specification changes do not involve a significant reduction in a margin of safety. All analyses supporting the SG replacement reflect these proposed values. The analyses results demonstrate applicable acceptance criteria are met. Setpoint calculations confirm that margin exists between the trip setpoints and the corresponding safety analysis limits. The calculations are based on FNP instrumentation and test methods and include allowances for operation of Model 54F SGs at uprated power conditions. All acceptance criteria (including LOCA peak clad temperature, DNB, RCS pressure, containment temperature and pressure, and dose limits) continue to be met. Therefore, the proposed changes do not involve a significant reduction in the margin of safety.

Based on the previous information and on the analyses performed, the proposed changes do not involve a significant hazards consideration as defined in 10 CFR 50.92.

II. RCS Leakage Limits and Steam Generator Inspections

TS or Bases	Title	Description
3.4.13	RCS Operational Leakage	SG leakage limits of 450 gpd from all SGs and 150 gpd from any one SG (Unit 1 only)
B 3.4.13	RCS Operational Leakage	Safety Analysis conservatively assumes 500 gpd
3.4.16	RCS Specific Activity	DEI limit 0.5 μCi/gm
Figure 3.4.16-1	DEI vs RTP	Revised curve based on DEI of 0.5 μCi/gm
B 3.4.16	RCS Specific Activity	Safety analyses conservatively assume 1440 gpd and 1.0 μCi/gm
B 3.7.16	Secondary Specific Activity	Reflects changes to RCS activity and leakage assumptions
5.5.9	SG Tube Surveillance Program	Eliminates F* criteria (Unit 2) and voltage-based alternate repair criteria and option to sleeve tubes (Units 1 & 2); redefines preservice inspection schedule; and provides one-time exemption for inservice testing
5.6.10	SG Tube Inspection Report	Remove the reporting requirements for sleeved tubes, ARC and F*

RCS Operational Leakage (3.4.13 and B 3.4.13)

The RCS Operational Leakage for SGs on Unit 1 is adjusted to match the current NRC approved limits for Unit 2. These limits are set at 150 gpd from any one SG and 450 gpd from all three SGs. The 450 gpd from all SGs reflect the 150 gpd multiplied by the number of SGs. These limits agree with the current guidance of EPRI and NEI for SG tube leakage and provide assurance that integrity of SG tubes will be maintained in the event of a MSLB. The Bases changes reflect the bounding safety analysis assumptions of 500 gpd and 470 gpd primary to secondary leakage in the ruptured and intact SGs respectively, and an RCS activity of 1.0 μCi/gm DEI for MSLB.

RCS Specific Activity (3.4.16, B 3.4.16 and Figure 3.4.16-1)

The RCS Specific Activity limit was adjusted from 0.15 to 0.5 μCi/gm. The new activity value is reflected in the revised curve for RCS Specific Activity vs Percent of Rated Thermal Power, shown in Figure 3.4.16-1. Radiological analyses performed for steam generator replacement use a value of 1.0 μCi/gm RCS Specific Activity and 1 gpm (1440 gpd) RCS Operational Leakage for SGs, thus bounding the Technical Specifications limits. The calculated offsite doses continue to meet the acceptance criteria of NUREG-0800. The increase in allowable RCS specific activity is acceptable based on the removal of the voltage-based alternate repair criteria. The value of 0.5 μCi/gm is well within established industry guidelines and below the original FNP value of 1.0 μCi/gm. Dose analyses provide acceptable results using 1.0 μCi/gm, and thus the value of 0.5 μCi/gm as the RCS Specific Activity limit provides additional conservatism. The Bases have been revised to reflect these proposed changes based on FNP specific calculation assumptions and analyses results.

Secondary Specific Activity (B 3.7.16)

Bases pages addressing Secondary Specific Activity are also being revised for consistency with the RCS Operational Leakage and RCS Specific Activity changes.

SG Tube Surveillance Program (5.5.9)

In the SG Tube Surveillance Program, the inspection criteria for SG tube inspections will change based on the characteristics of the new Model 54F SG. The revisions include the removal of the voltage-based alternate repair criteria and elimination of sleeving tube repairs for Unit 1 and Unit 2 as well as the F* SG tube plugging criteria for Unit 2. For the outage in which the SG replacement occurs, a one time exemption from the inservice inspection requirement is requested since the SG is new and preservice testing includes hydrostatic pressure testing and eddy current baseline examinations.

In the SG Tube Surveillance Programs acceptance criteria for Preservice Inspection, the unnecessary restriction that the preservice inspection be performed after the field hydrostatic pressure test and prior to Power Operation is being removed. The proposed change only affects the schedule for performing the preservice inspection of replacement SG tubing. The proposed change is in compliance with the requirements of Regulatory Guide 1.83, Revision 1, and Section XI of the ASME Boiler and Pressure Vessel Code. The proposed change is also acceptable because the preservice inspection of replacement SG tubes will be performed to establish the baseline condition of SG tubing and it does not reduce the effectiveness of the eddy current baseline inspection. Following SG replacement, subsequent inservice inspections will provide evidence of structural degradation of SG tubes.

The shop performed eddy current examinations will be performed after the required ASME Section III hydrostatic pressure test. This hydrotest will be conducted at a test pressure of 1.25 times the design pressure. Subsequent to installation of the replacement SGs, system hydrostatic pressure tests must be performed in accordance with ASME Section XI. These test pressures are substantially less than the Section III hydrotest and will not affect the results of the baseline eddy current examinations. Finally, the proposed change, as discussed above, is similar to and consistent with the baseline inspection philosophy already approved by the NRC for other operating nuclear power plants (e.g., NRC Safety Evaluation for North Anna Units 1 and 2, dated December 4, 1991).

In addition, several pages of Section 5.5 were re-numbered or deleted due to the removal of text associated with alternate repair and tube plugging criteria.

SG Tube Inspection Report (5.6.10)

In the SG Tube Inspection Report, the inspection criteria for SG tube inspections will change based on the characteristics of the new SG. The report changes are consistent with the inspection program changes including the removal of the voltage-based alternate repair criteria for Unit 1 and Unit 2, as well as the F* SG tube plugging criteria for Unit 2. These options are not applicable to the new Model 54F SG since a new tube material is being used and the current technical basis is no longer applicable. Sleeving will not be used. Tube plugging will be the acceptable method to correct a steam generator tube defective condition.

Additional minor editorial, typographical and format changes to the Technical Specifications, Bases and Programs sections are identified in the Technical Specifications, Bases and Programs sections mark-ups.

Based on the information presented above and the analyses and evaluations performed for the proposed SG replacement, the following conclusions can be reached with respect to 10 CFR 50.92.

1. The proposed changes do not significantly increase the probability or consequences of an accident previously evaluated in the FSAR. The comprehensive engineering effort performed to support SG replacement has included evaluations or re-analysis of all accident analyses including all dose related events. All dose consequences have been analyzed or evaluated with respect to these proposed changes, and all acceptance criteria continue to be met. Therefore, these changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. The proposed changes do not create the possibility of a new or different kind of accident than any accident already evaluated in the FSAR. No new accident scenarios, failure mechanisms or limiting single failures are introduced as a result of the proposed changes. The proposed technical specification changes have no adverse effects on any safety-related system and do not challenge the performance or integrity of any safety-related system. Therefore, these changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. The proposed technical specification changes do not involve a significant reduction in a margin of safety. All applicable analyses supporting the SG replacement reflect these proposed values. All acceptance criteria (including LOCA peak clad temperature, DNB, containment temperature and pressure, and dose limits) continue to be met. Therefore, the proposed changes do not involve a significant reduction in the margin of safety.

Based on the previous information and on the analyses performed, the proposed changes do not involve a significant hazards consideration as defined in 10 CFR 50.92.

III. Analysis Limits for RCS and Containment

TS or Bases	Title	Description
3.4.5	RCS Loops – Mode 3	Minimum SG Level = 75 % WR
B 3.4.5	RCS Loops – Mode 3	Minimum SG Level = 75 % WR
3.4.6	RCS Loops – Mode 4	Minimum SG Level = 75 % WR
B 3.4.6	RCS Loops – Mode 4	Minimum SG Level = 75 % WR
3.4.7	RCS Loops – Mode 5 Loops Filled	Minimum SG Level = 75 % WR
B 3.4.7	RCS Loops – Mode 5 Loops Filled	Minimum SG Level = 75 % WR
B 3.6.1	Containment	P_a = 43.8 psig
B 3.6.2	Containment Air Locks	P_a = 43.8 psig
B 3.6.4	Containment Pressure	Peak from MSLB = 52.0 psig and P_a = 43.8 psig
B 3.6.5	Containment Air Temperature	Peak from MSLB = 367 °F
B 3.6.6	Containment Spray and Cooling System	Peak from MSLB of 52.0 psig and 367 °F
5.5.17	Containment Leakage Rate Testing Program	P_a = 43.8 psig

RCS Loops – Modes 3, 4 and 5 loops filled (3.4.5, B 3.4.5, 3.4.6, B 3.4.6, 3.4.7 and B 3.4.7)

The minimum wide range level for decay heat removal will change from 74% WR to 75% WR to be consistent with the required water level for the Model 54F SG. This level ensures the SG tubes remain covered to provide an adequate heat sink. Setpoint uncertainty calculations confirm the acceptability of this setpoint. The results of the analyses conclude that since all acceptance criteria continue to be met, the proposed value is acceptable.

Containment, Containment Air Locks, Containment Pressure, and Containment Leakage Rate Testing Program (B 3.6.1, B 3.6.2, B 3.6.4 and 5.5.17)

The Containment Systems Bases pages and the Containment Leakage Testing Program changes for containment internal pressure response to LOCA events reflect the results of FNP containment analyses performed at uprated power operating conditions with the new Model 54F steam generators. The changes revise the LOCA peak pressure (P_a) from 43 to 43.8 psig. The analyses demonstrate that the containment remains within the design pressure limit of 54 psig for accident conditions, including an initial positive pressure of 3 psig. The change to the value in the FNP containment Leakage Rate Testing Program is consistent with the new LOCA analysis results and 10 CFR 50, Appendix J, Option B.

Containment Pressure, Containment Air Temperature, and Containment Spray and Cooling System (B 3.6.4, B 3.6.5 and B 3.6.6)

The Bases pages changes for containment internal pressure and temperature response to MSLB events reflect the results of FNP containment analyses performed at uprated power operating conditions with the new Model 54F steam generators. The peak calculated containment internal pressure for a MSLB event is decreased from 52.4 to 52.0 psig. The calculated containment temperature from the MSLB is decreased from 383 to 376°F. The analyses demonstrate that the containment remains within the design pressure limit, including an initial positive pressure of 3 psig, and within the design temperature limit for accident conditions.

Additional minor editorial, typographical and format changes to the Technical Specifications, Bases and Programs sections are identified in the Technical Specifications, Bases and Programs sections mark-ups.

Based on the information presented above and the analyses and evaluations performed for the proposed SG replacement, the following conclusions can be reached with respect to 10 CFR 50.92.

1. The proposed changes do not significantly increase the probability or consequences of an accident previously evaluated in the FSAR. The comprehensive engineering review effort performed to support SG replacement has included evaluations or re-analysis of all accident analyses including all dose related events. All ESF and containment systems will function as designed, and all performance requirements on these systems have been verified to be acceptable. Engineering has analytically determined the minimum SG level based on the new SG design features. The changes to containment pressure / temperature reflect the analyses results. The probability of an accident has not been increased. All dose consequences have been analyzed or evaluated with respect to these proposed changes, and all acceptance criteria continue to be met. Therefore, these changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. The proposed SG minimum WR level and containment pressure / temperature changes do not create the possibility of a new or different kind of accident than any accident already evaluated in the FSAR. No new accident scenarios, failure mechanisms or limiting single failures are introduced as a result of the proposed changes. The proposed technical specification changes have no adverse effects on any safety-related system and do not challenge the performance or integrity of any safety-related system. Therefore, these changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. The proposed technical specification changes do not involve a significant reduction in a margin of safety. Analyses supporting the SG replacement reflect the proposed SG minimum level value. Mass and energy, and containment response analyses modeled ESF systems and safety analysis limits. Setpoint calculations demonstrate that margin exists between applicable setpoints and the corresponding safety analysis limits. The containment temperature / pressure changes reflect the analysis results. All acceptance criteria (including LOCA peak clad temperature, DNB, RCS pressure, containment temperature and pressure, and dose limits) continue to be met. Therefore, the proposed changes do not involve a significant reduction in the margin of safety.

Based on the previous information and on the analyses performed, the proposed changes do not involve a significant hazards consideration as defined in 10 CFR 50.92.

Attachment 4

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

<u>NSSS Licensing Report</u>

WCAP-15098

Farley Nuclear Plant Units 1 and 2 Replacement Steam Generator Program NSSS Licensing Report

November 1998

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LIST OF ACRONYMS AND ABREVIATIONS

AB	Axial Blankets
AFW	Auxiliary Feedwater
AFWS	Auxiliary Feedwater System
AIB	Arbitrary Intermediate Line Breaks
ANS	American Nuclear Society
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transients Without Scram
AVB	Anti-Vibration Bar
BE	Best Estimate
BE LBLOCA	Best Estimate Large Break Loss-of-Coolant Accident
BEF	Best Estimate RCS Flow
BIT	Boron Injection Tank
BOL	Beginning of Life
BOP	Balance of Plant
C_D	Discharge Coefficient
CHG/SI	Charging/Safety Injection
CVCS	Chemical and Volume Control System
DC	Downcomer
DECLG	Double-Ended Cold Leg Guillotine
DEHL	Double-Ended Hot Leg
DEPS	Double-Ended Pump Suction
DER	Double-Ended Rupture
DFBN	Debris Filter Bottom Nozzle
DNB	Departure From Nucleate Boiling
DNBR	Departure From Nucleate Boiling Ratio
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOC	End of Cycle
EOL	End of Life
EQ	Environmental Qualification
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
FCV	Flow Control Valve
FDB	Flow Distribution Baffle
FF	Fouling Factor
FLB	Feedwater Line Break
FSAR	Final Safety Analysis Report
HHSI	High Head Safety Injection
HZP	Hot Zero Power
ID	Inside Diameter

LIST OF ACRONYMS AND ABREVIATIONS (Cont.)

IEEE	Institute of Electrical and Electronics Engineers
IFBA	Integral Fuel Burnable Absorbers
IFMs	Intermediate Flow Mixing Grids
J_{IC}	Fracture Toughness of Material Defining the Point of Crack Initiation
LBB	Leak Before Break
LBLOCA	Large Break Loss of Coolant Accident
LHSI	Low Head Safety Injection
LLSGL	Low-Low Steam Generator Water Level
LOCA	Loss of Coolant Accident
LOL/TT	Loss of Load/Turbine Trip
LONF	Loss of Normal Feedwater
LOOP	Loss of Offsite Power
LOPAR	Low Parisity
LPP	Low Pressurizer Pressure
LSP	Low Steamline Pressure
LTCC	Long-Term Core Cooling
M&E	Mass and Energy
MA	Mill Annealed
MDC	Moderator Density Coefficient
MFIV	Main Feedwater Isolation Valve
MFW	Main Feedwater
MMF	Minimum Measured Flow
MSIBV	Main Steam Isolation Bypass Valve
MSIV	Main Steam Isolation Valve
MSLB	Main Steamline Break
MSS	Main Steam System
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
NRC	Nuclear Regulatory Commission
NRS	Narrow Range Span
NSSS	Nuclear Steam Supply System
OBE	Operating Basic Earthquake
OD	Outside Diameter
OPΔT	Overpower Delta Temperature
OTΔT	Overtemperature Delta Temperature
PCT	Peak Clad Temperature
PCWG	Performance Capability Working Group
PORV	Power-Operated Relief Valve
PPM	Pulse Position or Phase Modulation
PS3	Power Shape 3

LIST OF ACRONYMS AND ABREVIATIONS (Cont.)

PWR	Pressurized Water Reactor
QMS	Quality Management System
RAOC	Relaxed Axial Offset Control
R_{BR}	Nominal Break Flow Flowpath Resistance Ratio
RCCA	Rod Cluster Control Assembly
RCL	Reactor Coolant Loop
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHRS	Residual Heat Removal System
RPS	Reactor Protection System
RSAC	Reload Safety Analysis Checklist
RSG	Replacement Steam Generator
RSHC	Reload Safety Analysis Checklist
RTDP	Revised Thermal Design Procedure
RTN	Reconstitutable Top Nozzle
RTP	Rated Thermal Power
RWST	Refueling Water Storage Tank
SBLOCA	Small Break Loss-of-Coolant Accident
SCS	Southern Company Services
SER	Safety Evaluation Report
SG	Steam Generator
SGTP	Steam Generator Tube Plugging
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIS	Safety Injection System
SLB	Steamline Break
SNC	Southern Nuclear Operating Company
SS	Stainless Steel
SSE	Safe Shutdown Earthquake
T_{avg}	Average Coolant Temperature
T_{cold}	Cold Leg Temperature
TDF	Thermal Design Flow
T_{hot}	Hot Leg Temperature
TSP	Tube Support Plate
TT	Thermally Treated
V5	VANTAGE 5/VANTAGE +
VCT	Volume Control Tank

EXECUTIVE SUMMARY

The purpose of the Farley Replacement Steam Generator (RSG) Program is to replace the current Model 51 steam generators with Westinghouse Model 54F steam generators.

In support of the Farley RSG Program, Westinghouse has performed analyses and evaluations for the Unit 1 and Unit 2 Nuclear Steam Supply Systems (NSSSs) to demonstrate that the Farley NSSS is in compliance with applicable licensing criteria and requirements at the uprated NSSS thermal power of 2785 MWt (reactor power of 2775 MWt) with the 54F RSG. The scope of the Westinghouse analyses and evaluations include the NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel. Those portions of the Westinghouse scope that are not adversely impacted[1] by steam generator replacement or were determined to be bounded by the Power Uprate Project (WCAP-14723, "Farley Nuclear Plant Units 1 and 2 Power Uprate Project NSSS Licensing Report"), are listed in Section 2.2. WCAP-14723 provided, in part, the technical basis for the power uprate approval from the Nuclear Regulatory Commission (NRC), dated April 29, 1998 and August 20, 1998. The NSSS analyses completed in support of the Power Uprate Project formed the basis of the NSSS analyses and evaluations performed for the RSG Program. In addition to the NSSS analyses performed by Westinghouse, other RSG analyses and evaluations were performed by Bechtel, Southern Company Services (SCS), and Southern Nuclear Operating Company (SNC).

This NSSS Licensing Report provides a description of the NSSS analyses and evaluations performed by Westinghouse for the RSG Program. A description of the analyses and evaluations performed for the Balance of Plant (BOP) secondary systems and components and the radiological/containment response analyses is provided in the BOP Licensing Report.

The results of the Westinghouse NSSS analyses and evaluations satisfy the project purpose and demonstrate that applicable licensing criteria and requirements are satisfied for the NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel at power uprate conditions with the Model 54F steam generators.

[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

1.0 INTRODUCTION

1.1 PURPOSE AND SCOPE

The purpose of performing the Farley RSG Program NSSS analyses and evaluations is to demonstrate that the Farley NSSS is in compliance with applicable licensing criteria and requirements and can operate acceptably at power uprate conditions with Model 54F steam generators. Table 2.2-1 lists the NSSS analyses that are either bounded by the Power Uprate Project or not adversely impacted[1] by the RSG Program. The remaining NSSS analyses and evaluations and their results are also listed in Table 2.2-1 and discussed within this report.

The Farley RSG Program scope is divided among SNC, SCS, Bechtel, and Westinghouse. The Westinghouse scope includes the NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel. The RSG analyses and evaluations described in this report are based on WCAP-14723, "Farley Nuclear Plant Units 1 and 2 Power Uprate Project NSSS Licensing Report," and the subsequent NRC approval dated April 29, 1998 and August 20, 1998. The NSSS analyses completed in support of the Power Uprate Project formed the basis of the NSSS analyses performed for the RSG Program.

1.2 METHODOLOGY AND ACCEPTANCE CRITERIA

The RSG analyses and evaluations were performed in accordance with Westinghouse quality assurance requirements defined in the Westinghouse Quality Management System (QMS) procedures, which comply with 10 CFR 50 Appendix B criteria. These analyses and evaluations are in conformance with Westinghouse and industry codes, standards and regulatory requirements applicable to Farley Units 1 and 2. Assumptions and acceptance criteria are provided in the appropriate sections of this report.

1.3 TECHNICAL BASIS FOR SIGNIFICANT HAZARDS EVALUATION

This report and the BOP Licensing Report provide the technical basis for the significant hazards evaluation included with the proposed Technical Specifications changes for the Farley RSG Program.

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[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

1.4 CONCLUSIONS

The results of the NSSS analyses and evaluations demonstrate that the Farley NSSS is in compliance with applicable licensing criteria and requirements and can operate acceptably at power uprate conditions with the Model 54F steam generators.

2.0 OVERVIEW OF NSSS CHANGES AND ANALYSES

Section 2.1 summarizes the changes to the NSSS that are a result of using the Model 54F RSGs, including the various steam generator design enhancements embodied in the Model 54F steam generators and other NSSS-related changes due the modified design. Section 2.2 categorizes each NSSS analysis area into (1) system analyses that are detailed in this report, and (2) RSG analyses that are bounded by the power uprate analyses or are not adversely impacted[1] by the Model 54F RSGs.

2.1 CHANGES DUE TO THE RSG

This section summarizes the steam generator design changes and other NSSS changes resulting from the RSGs.

2.1.1 Summary of Steam Generator Design Changes

When compared to the existing Model 51 steam generator, the Farley Model 54F RSG employs numerous design enhancements. The following is a list of the more significant design enhancements:

- Thermally treated Alloy 690 tubing provides much improved resistance to stress corrosion cracking.
- Enhanced anti-vibration bar design provides for a more stable tube bundle, and limits potential for both wear and high cycle fatigue of tubes.
- Corrosion resistant tube support plate materials limit potential for crevice corrosion product buildup.
- Structural broach hole cutout in tube support plates improves axial flow within tube bundle and minimizes tube-to-tube support contact area.
- Revised feedwater flow ring design addresses thermal stratification and water hammer.
- New steam flow taps address control/protection system requirements of Institute of Electrical and Electronics Engineers (IEEE)-279.
- Increased number and types of external shell penetrations provide for greater sludge and foreign object removal capabilities.

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[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

- Sludge collector provides a passive means of reducing the amount of sludge contained in the secondary-side flow, resulting in a reduction in the rate of sludge deposition within the tube bundle, thus enhancing steam generator reliability and performance.

- Improved steam separator performance improves warranted steam quality to 99.9 percent.

- Flow distribution baffle plate produces flow conditions on the secondary side of the tubesheet to minimize the size of the zone where sludge deposition can occur.

- A fixed steam generator water level control setpoint of 65 percent narrow range span (NRS).

- Forged secondary-side elliptical head with an intergral steam nozzle to eliminate the nozzle-to-head weld.

- Forged secondary-side components to eliminate longitudinal weld seams.

The basic design of the Model 54F steam generator is consistent with that of prior steam generators designed and manufactured by Westinghouse. Tables 2.1-1 and 2.1-2 provide a comparison of key steam generator parameters for the Model 51 steam generator (currently in operation at Farley Units 1 and 2) and the Model 54F RSG. Based on these design features, the RSG was analyzed in terms of the thermal-hydraulic and structural considerations. The Model 54F RSG is very similar to the current Model 51 steam generator and is considered by Westinghouse to be a very close replica.

Calculations and comparisons of the steam pressure, circulation ratio, moisture carryover, and stability damping factor for the NSSS performance conditions shown in Table 3.1-2 demonstrate that there are no design or performance issues associated with the revised conditions. From a thermal-hydraulic standpoint, the Model 54F steam generator design will be acceptable at the NSSS performance conditions shown in Table 3.1-2. The stresses and fatigue limits defined in the 1989 edition of the American Society of Mechanical Engineers (ASME) code will be the basis of acceptability for the RSG structural evaluation.

2.1.2 Summary of NSSS-Related Changes

2.1.2.1 LOCA Forces

Farley-specific LOCA hydraulic forces were developed for qualifying RCS loop piping and the Model 54F steam generators. The NRC-approved MULTIFLEX 1.0 computer code was used. To generate the transient coolant properties within the RCS, the time history RCS properties computed by MULTIFLEX are used in the THRUST code to calculate LOCA hydraulic forces. THRUST has been previously used in other applications. LBB has been applied to generate the LOCA forces.

2.1.2.2 RCL Piping, Supports, LBB

The RCL piping, supports, and associated leak before break (LBB) analyses are affected by the replacement of the Model 51 steam generators with a Model 54F. In addition, 15 of the steam generators snubbers in each unit are to be eliminated at the time the steam generators are replaced. The snubber elimination has an impact on the stresses and loads for the piping, supports, and LBB. The analysis of these three areas includes the effects of the RSG, snubber elimination, and revised loss of coolant accident (LOCA) forces. A discussion of the analyses is presented below.

2.1.2.2.1 Method of Analyses

The existing design basis reactor coolant loop (RCL) model is converted to a non-linear model suitable for time history seismic analyses to accommodate gapped supports in the system. The geometrical non-linear RCL model is connected with the equipment support structures and simplified reactor containment building model and subjected to time history seismic operating basis earthquake (OBE) and safe shutdown earthquake (SSE) analyses with all the steam generator snubbers removed.

Upon completion of the time history seismic analyses, the results are reviewed with respect to the increases in seismic loading and increased loading resulting from the modified steam generator support configuration for Items a through d below. The analysis is based on no postulated arbitrary intermediate line breaks in the main steamline. These breaks are eliminated based on Standard Review Plan 3.6.2.

a. RCL piping stress evaluation for critical load combinations and locations

b. Redemonstration of LBB at the critical location

c. Primary equipment nozzle loads at critical nozzles

d. Equipment support loads reviewed for critical support components

The results of the above review were then used to demonstrate that not only is the effect of the RSG on the loop piping, supports, and LBB acceptable, but also that all 15 steam generator snubbers can be removed from each unit with no hardware modifications and without any significant impact on the remainder of the plant.

2.1.2.2.2 RCL Piping

The maximum design condition combined stress due to OBE weight, and pressure in the reactor coolant loop piping is 21.1 ksi, which is less than the code allowable stress value of 26.7 ksi. The maximum faulted condition combined stress in the reactor coolant loop piping due to pressure, weight, SSE, and either a LOCA or a main steam or a feedwater break is 39.5 ksi, which is less than the code allowable stress value of 53.4 ksi. The maximum versus allowable stresses are shown in Table 2.1-3. The faulted stresses are based on conservative estimates for the LOCA and feedwater break cases.

Based on the above evaluation, the RCL piping components can be qualified in accordance with the stress criteria.

2.1.2.2.3 LBB Demonstration

The Farley Units 1 and 2 primary loop piping analyses performed by Westinghouse for the application of LBB is documented in WCAP-12825, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for the Joseph Farley Units 1 and 2 Nuclear Power Plants," and approved by the NRC in a letter dated August 12, 1991.

The purpose of the RSG analyses is to demonstrate the acceptability of LBB due to the RSG Program, including steam generator snubber elimination for the primary loop piping of Farley Units 1 and 2.

The loadings generated due to the RSG Program and steam generator snubber elimination are used in the analyses. The parameters that are important in the analyses are the piping forces, moments, normal operating temperature, normal operating pressure, and the material properties.

The flaw size (through-wall circumferential) to yield a leak rate of 10 gpm is calculated. The flaw size is called leakage flaw. Since the leakage flaw size is calculated for 10 gpm, a margin of 10 on the leak rate is satisfied (Farley RCS pressure boundary leak detection systems are designed to detect leakage of a minimum of 1 gpm in 1 hour). Stability analyses are performed at the critical locations using the plastic instability and J-integral methods. The appropriate combination of normal and faulted condition loading is used to calculate the critical flaw sizes. The margins on flaw sizes of 2.0 (a ratio of critical flaw to leakage flaw) are satisfied. The faulted loads are combined using the absolute summation method; therefore, a margin on loads of 1 is satisfied.

The analyses demonstrate the acceptability of LBB for the RCL piping using the loads from the RSG Program and steam generator snubber elimination time history seismic analysis. Based on the evaluation results, the LBB is demonstrated for the RCL piping. The recommended LBB margins per SRP 3.6.3 for the leak rate of 10, flaw size of 2, and loads of 1 (using absolute summation method of faulted load combination) are demonstrated at the critical locations.

The LBB analysis for the pressurizer surge line is documented in WCAP-12835, "Technical Justification for Eliminating Pressurizer Surge Line Rupture from the Structural Design Basis for Farley Units 1 and 2," and Supplement 1 of WCAP-12835, and approved by the NRC in a letter dated January 15, 1992. There is negligible impact on the pressurizer surge lines due to the RSG Program and steam generator snubber elimination and, therefore, there is no change in the existing LBB analysis.

In summary, the effects of the RSG Program and the steam generator snubber elimination on the continued applicability of leak-before-break for the reactor coolant loop piping and the pressurizer surge lines at the Farley Nuclear Power Plants have been evaluated. It is concluded that the conclusions of the previous LBB analysis remain valid, and that the dynamic effects of the pipe rupture resulting from postulated breaks in the reactor coolant system primary loop piping and the pressurizer surge lines need not be considered in the structural design basis of the Farley Units 1 and 2 Nuclear Power Plants after the RSG and the steam generator snubber elimination.

2.1.2.2.4 RCL Supports

The results of the stress evaluation of the primary equipment supports for Farley Units 1 and 2 are summarized in this section. The manner in which the stresses are calculated is described, and maximum member stresses for each of the loading combinations are tabulated.

For the normal condition, the thermal, weight, and pressure forces (obtained from the RCL analysis) acting on the support structures are combined algebraically. The combined load component vector is used in the determination of the stress of each member in the support system.

Table 2.1-4 gives maximum stresses in members of the steam generator and the reactor coolant pump structural supports, expressed as a percentage of maximum permissible values for each of the operating condition loadings. The stresses in all pins, bolts, and connections that are a part of the steam generator and reactor coolant pump supports are well within allowable values.

The reaction of the reactor vessel support structures to an applied force resulting from all loading conditions is analyzed via a finite element model. Dynamic forces applied to these structures are the combination of forces obtained from the RCL analysis, reactor cavity pressure, and the reactor vessel internals analysis. The maximum stress intensity of the elements of the reactor vessel supports, as a percentage of the allowable stress intensity, is given in Table 2.1-5.

The results show that the stresses on the RCL supports remain within the allowable stresses with the increased loads due to the RSG and snubber elimination.

2.1.2.2.5 RCL Equipment Nozzle Load Evaluation

A comparison of the increased RCL primary equipment nozzle loads to the umbrella allowable loads given in the equipment design specification shows that there is sufficient design margin to accommodate the higher nozzle loads resulting from the revised steam generator support configuration.

2.1.2.2.6 Conclusions

A time history seismic OBE and SSE analysis, main steam break analysis, and critical feedwater break analysis were performed for Farley Units 1 and 2 to demonstrate the acceptability of

removing all the ste m generator snubbers in conjunction with replacing the steam generato:.
The results are summarized below:

a. The design margin in the design basis calculations can accommodate the new stresses in the RCL piping components such that the applicable stress criteria can be met.

b. LBB for the RCL piping and pressurizer surge line can be demonstrated and was applied in the determination of the LOCA hydraulic forces.

c. There is sufficient margin in the equipment nozzle load design basis calculation to accommodate the new nozzle loads.

d. Stresses in all the support members of the reactor pressure vessel, reactor coolant pump, and steam generator are within the allowable values for normal, upset, and faulted conditions.

2.1.2.3 RCS Volumes

The RCS volumes and associated masses increase slightly due to the increased number of tubes and the resultant increase in the primary-side steam generator volume. A comparison of the RCS volumes and masses for the power uprate with the Model 51 steam generator and with the Model 54F steam generator is provided in Tables 2.1-6 and 2.1-7, respectively. The effects of RCS volume changes are described in the applicable analysis and evaluation discussions.

Table 2.1-1
Comparison of Key Steam Generator Parameters

Parameter	Model 51	Model 54F
Heat Transfer Area, ft^2	51,500	54,500
Number of Tubes	3,388	3,592
Tube OD, inches	0.875	0.875
Tube Wall Thickness, inches	0.050(1)	0.050
Tube Material	Alloy 600 MA(2)	Alloy 690 TT(2)
Tube Pitch, inches	1.281	1.225
Pitch Arrangement	Square	Square
Minimum U-Bend Radius, inches	2.1875	3.141
Maximum U-Bend Radius, inches	59.884	59.491
Wrapper ID, inches	123.50	123.50
Wrapper Opening Height, inches	14.00	14.00
Tube Bundle Height, inches	~418.	~418.
Number of Tube Support Plates/Flow Distribution Baffles (FDBs)	7/0	7/1
Tube Hole Configuration	Round	Octafoil (FDB) Structural Broach (TSPs)
Support/Baffle Material	Carbon Steel	405 SS(3)
Number of U-Bend AVBs	2 Sets	3 Sets
U-Bend AVB Material	405 SS(3)	405 SS(3)
Primary Flow Area (20% SGTP), ft^2	8.884	9.414
Number of Primary Separators	3	16
Diameter of Primary Separators	56"	20"
Estimated Total Dry Weight, U.S. Ton	331	360
Center of Gravity from Steam Generator Support, inches	350.5	357
Overall Length, inches	813	813
Lower Shell OD, inches	135.0	135.5
Upper Shell OD, inches	175.75	176.92
Lower Shell ID, inches	129.38	129.38
Upper Shell ID, inches	168.50	168.50

Table 2.1-1 (Cont.) Comparison of Key Steam Generator Parameters		
Parameter	**Model 51**	**Model 54F**
Swirl Vane Angle, degrees	37.00	30.00
Primary Separator Design	Centrifugal	Centrifugal/Low Pressure Drop
Secondary Separator Design	Two Tier (8 Banks)	Single Tier (6 Banks)
Secondary Separator Face Area, ft^2	179.	192.
Number of Steam Nozzle Flow Venturi	7	7
Flow Limiter Flow Area, ft^2	1.069	1.069

Notes:

(1) As-built measurements of tube wall thickness for older model Westinghouse steam generators tubing indicate actual wall thicknesses approximately 5% larger than nominal, or 0.0525 inches.

(2) MA - Mill Annealed
TT - Thermally Treated

(3) SS - Stainless Steel

Table 2.1-2
Comparison of Model 51 and Model 54F Best Estimate Full-Load Performance for Farley Units 1 and 2

Parameter	Model 51	Model 54F
Steam Generator Thermal Power, MWt/SG	928.33	928.33
Primary Flowrate, gpm/SG	95,100$^{(1)}$	96,100
Fouling Factor, hr-ft^2-°F/Btu	0.00001	0.00006
SG Average Primary-Side Temperature, °F$^{(2)}$	577.1	577.1
SG Inlet Primary-Side Temperature, °F$^{(2)}$	610.0	609.7
SG Outlet Primary-Side Temperature, °F$^{(2)}$	544.1	544.4
SG Primary-Side Pressure Drop, psi	34.7	30.4
SG Primary-Side Volume, ft$^{3\,(3)}$	1,080	1,135
Primary-Side Mass, lbs$^{(3)}$	48,400	50,900
Percent Tube Plugging	0.0	0.0
Normal Full-Load Water Level, inches	506	520
Normal Full-Load Water Level, % NRS	58	65
Feedwater Temperature, °F	443.4	443.4
Steam Pressure, psia for T_{avg} = 577.2°F • 0% SGTP • 20% SGTP	 798$^{(4)}$ 744$^{(4)}$	 817$^{(5)}$ 724$^{(6)}$
Steam Flowrate, lb/hr	4.085E06	4.085E06
Circulation Ratio	~4.5 - 5.0	~3.5
Maximum Design Moisture Carryover, %	0.25	0.10
SG Secondary-Side Volume, ft$^{3\,(3)}$	5,730	5,643
SG Secondary-Side Mass, lbs$^{(3)}$	111,200$^{(7)}$	108,200

Notes:

(1) Estimated value.
(2) Steam generator T_{avg} from PCWG parameters is assumed in conjunction with best estimate flowrate.
(3) Per steam generator based on full-power operating conditions.
(4) Based on a design fouling factor of 0.000055 hr-ft^2-°F/Btu.
(5) Based on a fouling factor of 0.0 hr-ft^2-°F/Btu to provide a conservatively high steam pressure.
(6) Based on a design fouling factor of 0.00011 hr-ft^2-°F/Btu.
(7) Secondary-side mass based on a circulation ratio of 4.8.

Table 2.1-3 Class 1 RCL Piping ASME Stress Actual versus Allowable - Equation 9				
	Eq. 9⁽¹⁾ Design Maximum (ksi)	Eq. 9⁽¹⁾ Design Allowable (ksi)	Eq. 9⁽¹⁾ Faulted Maximum (ksi)	Eq. 9⁽¹⁾ Faulted Allowable (ksi)
Hot Leg	19.4	26.7	39.5	53.4
Crossover Leg	17.8	24.0⁽²⁾	26.5	48.0⁽²⁾
Cold Leg	15.7	26.7	31.5	53.4

__Notes__:

(1) Equation 9 from ASME Code, Section 3, NB-3650

(2) This allowable RCL piping stress is the lesser of the existing and the RSG outlet replacement elbows.

Table 2.1-4 Steam Generator and Reactor Coolant Pump Support Structure Percentage of Allowable Stresses for Normal, Upset, and Faulted Conditions			
Support Component	Normal (%)	Upset (%)	Faulted (%)
Steam Generator Columns	34	42	90
Steam Generator Lower Bumpers	0	31	23
Steam Generator Upper Bumpers	0	18	18
Reactor Coolant Pump Columns	30	31	42
Reactor Coolant Pump Tie Rods	0	26	36

Table 2.1-5
Reactor Vessel Support Structure Percentage of Allowable Stresses for Normal, Upset, and Faulted Conditions

Support Component	Maximum Stress Intensity (ksi)	Allowable Stress Intensity (ksi)	Maximum Stress, % of Allowable
Normal	$P_m = 6.1$ $P_m + P_b = 14.3$	$S_m = 23.3$ $1.5\ S_m = 35.0$	41
Upset	$P_m = 8.8$ $P_m + P_b = 16.3$	$S_m = 23.3$ $1.5\ S_m = 35.0$	47
Faulted	$P_m = 15.8$ $P_m + P_b = 23.7$	$0.7\ S_u = 41.5$ $1.05\ S_u = 62.3$	38

Table 2.1-6 RCS Component Volumes (Cold)		
Component	Volume (Cubic Feet)	
	Power Uprate	RSG
T_{hot} Volume		
Vessel	1437.217	1437.217
Hot Leg	3(80.69)	3(80.69)
SG Inlet	3(157.00)	3(157.00)
Total	2150.287	2150.287
T_{avg} Volume		
Vessel	528.43	528.43
SG Tubes	3(775.3)	3(821.4)
Total	2854.33	2992.63
T_{cold} Volume		
Vessel	1732.51	1732.51
SG Outlet	3(157.00)	3(157.00)
Crossover Leg	3(123.38)	3(123.38)
RCP	3(81.00)	3(81.00)
Cold Leg	3(87.82)	3(87.82)
Total	3080.11	3080.11
Pressurizer Steam Volume	790.5 @ T_{avg} = 567.2°F 651.75 @ T_{avg} = 577.2°F	790.5 @ T_{avg} = 567.2°F 651.75 @ T_{avg} = 577.2°F
Pressurizer Liquid Volume	667.57 @ T_{avg} = 567.2°F 806.32 @ T_{avg} = 577.2°F	667.57 @ T_{avg} = 567.2°F 806.32 @ T_{avg} = 577.2°F

Table 2.1-7 RCS Liquid Masses (Hot Full Power)				
SG Plugging Level (%)	RCS Mass (lb_m)			
	T_{avg} = 567.2°F		T_{avg} = 577.2°F	
	Power Uprate	RSG	Power Uprate	RSG
0	412,472	418,982	410,809	417,219
15	396,049	401,583	394,637	400,087

2.2 NSSS ANALYSES AND EVALUATIONS SUMMARY

2.2.1 Summary of NSSS Analyses and Evaluations

The NRC recently approved a power uprate for Farley Units 1 and 2. This approval is documented in References 1 and 2. The NSSS analyses completed in support of the Power Uprate Project formed the basis of the NSSS analyses performed for the RSG Program.

In support of the RSG Program, the NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel areas were either analyzed or evaluated to demonstrate that the applicable licensing criteria and requirements are satisfied. These analyses and evaluations consider the effects of the RSG at the uprated power level. It is concluded that some of the analysis and evaluations are impacted by the RSG, while others are either bounded by the power uprate analyses or not adversely impacted[1] by the RSGs. The NSSS analysis areas are listed in Table 2.2-1. The analyses and evaluations that are impacted by the RSG are discussed in Section 4.0.

2.2.2 Summary of Computer Codes

Principal computer codes used to support analyses presented in this report fall into two categories. The first category contains codes previously used on Farley applications. The second category contains new codes or revisions to previously used codes. All codes have been used within their limitations and restrictions.

2.2.2.1 Previously Used Computer Codes

The following principal computer codes have been documented and used on Farley for the Power Uprate Project as delineated in WCAP-14723 and responses to a request for additional information from SNC to the NRC (Reference 3).

1. MULTIFLEX 1.0
2. LOCTA-IV
3. SATAN VI
4. WREFLOOD
5. EPITOME
6. FROTH

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[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

7. LOFTRAN

8. THINC-IV

2.2.2.2 New or Revised Computer Codes

This section summarizes the computer codes that are either new or revisions to previously used computer codes.

Structural codes such as THRUST, WECAN, and WESTDYN were used in support of the Farley steam generator replacement. WCAP-8252, "Documentation of Selected Westinghouse Structural Analysis Computer Codes.", was issued to the NRC for review in April 1974. Subsequently, WCAP- 8252, Revision 1, was issued in May 1977, to include NRC questions and Westinghouse responses. This WCAP is specifically called out in the Farley FSAR as a reference for structural analyses. WCAP-8252, Revision 1, specifically addresses codes such as STHRUST, WECAN, WESTDYN2, and WESTDYN7. These codes were the predecessors for the revisions of THRUST, WECAN, and WESTDYN currently used by Westinghouse for licensing applications.

WCOBRA/TRAC, Version MOD7A, Revision 1 was used for BELOCA in support of WCAP-14723. Subsequent to NRC approval of the BELOCA for Farley, several changes have evolved. Revision 4 was used in support of the RSG Program (Reference 4).

Small break LOCA (SBLOCA), as presented in WCAP-14723, used the NOTRUMP code (References 5 and 6). The SBLOCA analysis for the RSGs used the NOTRUMP code, including the effects of safety injection in the broken loop and COSI condensation model (Reference 7). The use of COSI has been reviewed and approved by the NRC.

RETRAN-02 was used for several non-LOCA analyses and mass and energy release analyses. The description of the RETRAN-02 code is provided in Section 4.2 and is documented in References 8 and 9.

2.2.3 References

1. Letter from USNRC to SNC, *Issuance of Amendments - Joseph M. Farley Nuclear Plant, Units 1 and 2 (TAC Nos. M98120 and M98121)*, April 29, 1998

2. Letter from USNRC to SNC, *Supplement to Safety Evaluation Associated with Amendment Nos. 137 (Unit 1) and 129 (Unit 2)*, (TAC Nos. MA2469 and MA2470), August 20, 1998

3. Letter from SNC to NRC, *Response to Request for Additional Information Related to Prior Uprate Facility Operating License and Technical Specifications Change Request*, November 19, 1997

4. Letter, H. A. Sepp (W) to T. E. Collins (USNRC), *1997 Annual Notification of Changes to the Westinghouse Small Break LOCA and Large Break LOCA ECCS Evaluation Models, Pursuant to 10 CFR 50.46 (a)(3)(ii)*, NSD-NRC-98-5575, April 8, 1998

5. Meyer, P. E., *NOTRUMP - A Nodal Transient Small Break and General Network Code*, WCAP-10079-P-A (Proprietary) and WCAP-10080-NP-A (Non-Proprietary), August 1985

6. Lee, N. et al., *Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code*, WCAP-10054-P-A (Proprietary) and WCAP-10081-NP-A (Non-Proprietary), August 1985

7. Thompson, C. M., et al., *Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model*, WCAP-10054-P-A Addendum 2, Rev. 1 (Proprietary), July 1997

8. C. E. Peterson, et al., *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, EPRI NP-1850-CCM, Rev. 6, December 1995

9. D. S. Huegel, et al., *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, WCAP-14882-P (Proprietary), June 1997

Table 2.2-1 Summary of NSSS Analyses		
Analysis Title	Impacted by RSG and Included in WCAP-15098	Bounded by Uprate or Not Adversely Impacted[1] by RSG
NSSS PARAMETERS		
Design PCWG Parameters	X	
NSSS DESIGN TRANSIENTS		
NSSS Design Transients		X
Auxiliary Equipment Design Transients		X
NSSS SYSTEMS		
NSSS Fluid Systems		
Reactor Coolant System		X
Chemical and Volume Control System		X
Safety Injection System		X
Residual Heat Removal System		X
Boron Recycle System		X
Boron Thermal Regeneration System		X
Waste Gas Processing System		X
Mid-Loop Operations		X
NSSS/BOP Fluid Systems Interfaces		X
NSSS Control Systems		
Control Systems Stability		X
Plant Operability Margins		X
NSSS Component Sizing		X
P-9 Setpoint		X
Cold Overpressure Protection System		X
NSSS COMPONENTS		
Reactor Vessel Structural		X
Reactor Vessel Internals		X
Fuel Assemblies Structural		X

[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

Table 2.2-1 (Cont.) Summary of NSSS Analyses		
Analysis Title	Impacted by RSG and Included in WCAP-15098	Bounded by Uprate or Not Adversely Impacted[1] by RSG
NSSS COMPONENTS (Cont.)		
Control Rod Drive Mechanisms		X
RCL, Piping, Supports, and LBB	X	
Reactor Coolant Pump		X
Steam Generators	X	
Pressurizer		X
NSSS Auxiliary Equipment		X
NSSS ACCIDENT ANALYSES		
LOCA Transients		
Best Estimate Large Break LOCA	X	
Small Break LOCA	X	
Hot Leg Switchover		X
Post-LOCA Long-Term Core Cooling		X
Rod Ejection Accident Analysis		X
Non-LOCA Transients		
Uncontrolled RCCA Withdrawal from a Subcritical Condition		X
Uncontrolled RCCA Bank Withdrawal at Power		X
RCCA Misalignment		X
Uncontrolled Boron Dilution		X
Partial Loss of Forced Reactor Coolant Flow		X
Startup of an Inactive Reactor Coolant Loop		X
Loss of External Electrical Load and/or Turbine Trip		X
Loss of Normal Feedwater	X	
Loss of All ac Power to the Station Auxiliaries	X	

[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

Table 2.2-1 (Cont.)
Summary of NSSS Analyses

Analysis Title	Impacted by RSG and Included in WCAP-15098	Bounded by Uprate or Not Adversely Impacted[1] by RSG
Non-LOCA Transients (Cont.)		
Excessive Heat Removal Due to Feedwater System Malfunctions		X
Excessive Load Increase Incident		X
Accidental Depressurization of the RCS		X
Accidental Depressurization of the Main Steam System*		X
Inadvertent Operation of the ECCS During Power Operation		X
Minor Secondary System Pipe Breaks		X
Inadvertent Loading of a Fuel Assembly into an Improper Position		X
Complete Loss of Forced Reactor Coolant Flow		
Single Rod Cluster Control Assembly Withdrawal at Full Power		X
Rupture of a Main Steamline at Zero Power	X	
Major Rupture of a Main Feedwater Pipe	X	
Single Reactor Coolant Pump Locked Rotor		X
Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)		X
Steam System Piping Failure at Full Power*		X
ATWS Evaluation		X

[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

Table 2.2-1 (Cont.) Summary of NSSS Analyses		
Analysis Title	Impacted by RSG and Included in WCAP-15098	Bounded by Uprate or Not Adversely Impacted[1] by RSG
SGTR Transient	X	
LOCA Mass and Energy Releases		
Long-Term LOCA Mass and Energy Releases	X	
Short-Term LOCA Mass and Energy Releases		X
MSLB Mass and Energy Releases		
MSLB Mass and Energy Releases Inside Containment	X	
MSLB Mass and Energy Releases Outside Containment	X	
Steam Releases for Radiological Dose Analysis	X	
LOCA Hydraulic Forces	X	
NUCLEAR FUEL		
Core Thermal-Hydraulic Design		X
Fuel Core Design		X
Fuel Rod Design and Performance		X
Radiation Engineering Evaluation		X

Notes:
* Bounded by Rupture of Main Steamline at Zero Power analysis performed for the RSG Program.

[1] Throughout this report, the term "not adversely impacted," is used when the results of an analysis performed as part of the RSG Program demonstrate that the Model 54F RSGs require only a minimal change to the current analysis of record, and that the analysis still meets the acceptance criteria. The analyses that are impacted by the RSGs are presented in this report and either support Technical Specification changes or are not considered bounded by submittals previously reviewed by the NRC.

3.0 NUCLEAR STEAM SUPPLY SYSTEM PARAMETERS

Bounding NSSS Performance Capability Working Group (PCWG) Parameters were developed for use in the analyses and evaluations of the NSSS, including NSSS design transients, systems, components, accidents, and nuclear fuel. These PCWG parameters are described in Section 3.1.

3.1 DESIGN PCWG PARAMETERS

3.1.1 Introduction

The NSSS PCWG parameters are the fundamental parameters used as input in the NSSS analyses. They provide the RCS and secondary system conditions (e.g., temperatures, pressures, flow) that are used as the basis for the design transients, systems, components, accidents, and fuel analyses and evaluations.

The PCWG parameters have been established using conservative assumptions to provide bounding conditions for the NSSS analyses and to allow Farley Units 1 and 2 operating flexibility. To achieve this, a range of conditions was set based on the vessel average coolant temperature (T_{avg}) and the steam generator tube plugging (SGTP) level. The T_{avg} range is 567.2°F to 577.2°F, while the SGTP level can vary from 0 percent to 15 percent on average, with a maximum of 20 percent peak SGTP in any one steam generator.

Since NSSS analyses were completed recently as part of the Power Uprate Project (Reference 1), it is advantageous to establish conservative PCWG parameters as close as possible to those which formed the basis of that project. Therefore, the thermal design flow (TDF) value of 86,000 gpm/loop, T_{avg} range of 577.2°F to 567.2°F, and 15 percent average/20 percent peak SGTP form the basis of all the parameter cases since the replacement Model 54F steam generators have performance characteristics similar to the current Model 51 steam generators and by employing the same input parameters that were used for previous analyses, many analyses were shown to be bounded by the current analyses.

3.1.2 Input Parameters and Assumptions

The input parameters and assumptions used in the calculation of the PCWG parameters established for the RSG Program are summarized in Table 3.1-1. The major inputs used in the generation of the PCWG parameters follow:

- The NSSS power level was set at 2785 MWt (2775 MWt core), the same value used for the Farley Power Uprate Project.

- The TDF of 86,000 gpm/loop incorporated sufficient margin to support a 15 percent average SGTP. This conservative flow was applied for all cases and is the same value used for the Farley Power Uprate Project.

- Three values of SGTP were assumed: 0 percent, 15 percent, and 20 percent. Each unit is limited to a 15 percent average level, which provides maximum margin allowance for future tube plugging. The 20 percent SGTP level allows for up to 20 percent plugging in any steam generator, as long as the average of the three steam generators is not above 15 percent. With the RSGs, it is not expected that the tube plugging levels would ever reach this high, but these levels were assumed to be consistent with those of the power uprate analyses.

- Design core bypass flow was assumed to be 7.1 percent with the thimble plugs not installed, this is a conservative assumption. All applicable accident analyses have been performed in two ways: with the thimble plugs assumed to be installed and not installed. This is consistent with the Farley Units 1 and 2 power uprate analysis.

- A range of full power normal operating T_{avg} from 567.2°F to 577.2°F was selected for the analyses. This is the same range on which all of the present analyses (from power uprate), are based. The 10°F temperature window is sufficient to cover the projected operating temperature range of both Farley units with the RSGs.

3.1.3 Acceptance Criteria for Determining Parameters

The primary acceptance criteria for determining the RSG PCWG parameters dictate that the parameters must provide Farley Units 1 and 2 with adequate flexibility and margin for plant operation, while at the same time bounding the expected operating conditions that will occur at the plant.

3.1.4 Discussion of Parameter Cases

Table 3.1-2 provides the NSSS PCWG parameter cases that were generated and used as the basis for the RSG Program. A description of the six RSG cases follows.

Cases 1 through 3 each represent the RSG conditions at a vessel average temperature of 577.2°F; the difference between the three cases is the assumed SGTP level. Case 1 is based on 0 percent SGTP (to provide conservatively high secondary-side performance conditions), Case 2 assumes 15 percent SGTP, and Case 3 assumes 20 percent SGTP. Although the plant is limited to 15 percent average and 20 percent peak SGTP in any one steam generator, the parameters in Case 3 are based on uniform 20 percent SGTP as a simplifying, bounding assumption for analysis purposes. Note that all the primary-side temperatures are identical for each of these cases.

Cases 4 through 6 reflect the same input assumptions as Cases 1 through 3 except that a reduced T_{avg} of 567.2°F is used. As such, Cases 4 through 6 yield the lowest possible design cold leg temperature for the analyses, as well as the minimum secondary-side steam generator pressure and temperature.

Footnote 3 is included to provide a bounding, maximum set of secondary-side conditions (steam pressure of 817 psia, steam temperature of 520.6°F, and steam flow of 12.26×10^6 lb/hr, which are determined based on a best estimate, expected T_{avg} of 575°F) for those analyses for which higher values are more limiting. These are provided separately since the parameters are determined based on a conservatively high fouling factor in the steam generator, which minimizes the steam conditions. The maximum steam conditions are determined with an assumed fouling factor of 0 hr-ft^2-°F/Btu, which provides maximum heat transfer performance in the steam generator.

Footnote 8 for Cases 5 and 6 is included to allow the analysts to assume the minimum steam conditions used for the Power Uprate Project instead of the conservatively low conditions calculated for the RSG. This was done so that it would not be necessary to repeat certain analyses as it is recognized that Farley Units 1 and 2 cannot operate at the low steam pressures and temperatures calculated for the RSG due to limitations in the turbine.

3.2 CONCLUSIONS

The six cases of PCWG parameters were issued to the various Westinghouse analysts for input to their analyses. The Westinghouse analysts performed their analyses and evaluations based on the parameter set or sets which were most limiting so that the analyses would support operation of Farley Units 1 and 2 over the range of conditions specified.

3.3 REFERENCES

1. *Farley Nuclear Plant Units 1 and 2 Power Uprate Project NSSS Licensing Report*, WCAP-14723 (Proprietary) and WCAP-14724 (Non-Proprietary), January 1997

Table 3.1-1
NSSS PCWG Input Parameters for Farley RSG Program

Parameter	RSG
FUEL TYPE AND FEATURES	
Type	VANTAGE 5/VANTAGE +
IFMs (Yes/No)	Yes
Fuel Rod OD (Inches)	0.360
Number of Grids/Material	6 ZIRLO™, 2 Inconel, 3 IFM, 1 Protective Grid/Inconel
Clad Material	ZIRLO™/Zirc 4
Peaking Factors	
F_Q	2.5 (V5)(1)
$F_{\Delta H}$	1.7 (V5)(1)
P_{HA}	1.574 (V5)(1)
NSSS THERMAL POWER	
NSSS Power (MWt)	2785
Core Power (MWt)	2775
Net RCP Heat Input (MWt)	10
RCS FLOW	
Thermal Design Flow (gpm/loop)	86,000
Flow Measurement Uncertainty (%)	2.1 - 2.4(2)
Total Design Core Bypass Flow (%)	7.1
Thimble Plugs (In/Out)	In/Out(3)
RCS TEMPERATURE	
Vessel Average (°F)(4)	567.2 - 577.2
Vessel Outlet (°F)(4)	–
RCS PRESSURE (psia)	2250

Table 3.1-1 (Cont.) NSSS PCWG Input Parameters for Farley RSG Program	
Parameter	**RSG**
STEAM GENERATOR	
Steam Pressure (psia)[5]	_[6]
Moisture Carryover, Max (%)	0.10
Steam Generator Tube Plugging Level, Max (%)	15 avg/20 peak
BOP SYSTEMS	
Main Feedwater Temperature (°F)	443.4[7]

Notes:

(1) Analyses and/or evaluations will be performed to provide bounding values for LOPAR fuel (and V5 fuel adjacent to LOPAR assemblies) in case LOPAR fuel assemblies are used in the core. These will be addressed as necessary during the reloading process by use of approved methodologies. Peaking factors are not used as input in the calculation of PCWG parameters.

(2) Analyses cover range of flow measurement uncertainty from 2.1 to 2.4 percent.

(3) Analyses address thimble plugs being both installed and not installed to provide the option to operate with thimble plugs installed in the future.

(4) Only T_{avg} or T_{hot} is used as an input to the NSSS PCWG parameter analysis. Neither is used as an input if steam generator outlet steam pressure is used as an input. See Note 5.

(5) Steam generator outlet steam pressure may be used as an input to the NSSS PCWG parameter analysis if it is specified (e.g., to support turbine generator MWe output) for use in the determination of a vessel T_{avg} or vessel T_{hot}.

(6) On a best estimate basis, the RSG outlet steam pressure is to be equal to or above 787 psia (consistent with the turbine generator performance analysis completed for power uprate). The NSSS PCWG Parameters for use in the NSSS design and safety analyses may specify lower values for steam generator outlet steam pressure consistent with NSSS PCWG parameter analysis methodology (e.g., use of a conservatively high steam generator fouling factor and maximum SGTP levels).

(7) The feedwater temperature value of 443.4°F is consistent with NSSS PCWG parameter analysis methodology for the uprated power level of 2785 MWt. On a best estimate basis, the feedwater temperatures for Unit 1 and Unit 2 are anticipated to be within a couple degrees of this value.

Table 3.1-2
NSSS PCWG Parameters for Farley RSG Program

BASIC COMPONENTS			
Reactor Vessel, ID, in.	157	Isolation Valves	No
Core		Number of Loops	3
Number of Assemblies	157	Steam Generator	
Rod Array	17x17V5[1]	Model	54F
Rod OD, in.	0.360	Shell Design Pressure, psia	1100
Number of Grids	6Z/2I/3IFM	Reactor Coolant Pump	
Active Fuel Length, in.	144	Model/Weir	93A/Yes
Number of Control Rods, FL	48	Pump Motor, hp	6000
Internals Type	ALA	Frequency, Hz	60

	Replacement Model 54F Steam Generator Cases					
THERMAL DESIGN PARAMETERS	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
NSSS Power, %	100	100	100	100	100	100
MWt	2785	2785	2785	2785	2785	2785
10^6 BTU/hr	9503	9503	9503	9503	9503	9503
Reactor Power, MWt	2775	2775	2775	2775	2775	2775
10^6 BTU/hr	9469	9469	9469	9469	9469	9469
Thermal Design Flow, Loop gpm	86,000	86,000	86,000	86,000	86,000	86,000
Reactor 10^6 lb/hr	98.1	98.1	98.1	99.5	99.5	99.5
Reactor Coolant Pressure, psia	2250	2250	2250	2250	2250	2250
Core Bypass, %	7.1[2]	7.1[2]	7.1[2]	7.1[2]	7.1[2]	7.1[2]
Reactor Coolant Temperature, °F						
Core Outlet	618.1	618.1	618.1	608.8	608.8	608.8
Vessel Outlet	613.3	613.3	613.3	603.8	603.8	603.8
Core Average	581.8	581.8	581.8	571.7	571.7	571.7
Vessel Average	577.2	577.2	577.2	567.2	567.2	567.2
Vessel/Core Inlet	541.1	541.1	541.1	530.6	530.6	530.6
Steam Generator Outlet	540.8	540.8	540.8	530.3	530.3	530.3
Steam Generator						
Steam Temperature, °F	515.5[3]	509.5	506.9	504.6	498.5	495.9
Steam Pressure, psia	781[3,4]	741[4]	724[4]	709[4]	671[3,8]	656[3,8]
Steam Flow, 10^6 lb/hr total	12.24[3]	12.23	12.22	12.22	12.20	12.20
Feed Temperature, °F	443.4	443.4	443.4	443.4	443.4	443.4
Moisture, % max.	0.10	0.10	0.10	0.10	0.10	0.10
App. F'F', hr. sq. ft. °F/BTU	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011
Tube Plugging, %	0	15[5]	20[5]	0	15[3]	20[3]
Zero Load Temperature, °F	547	547	547	547	547	547
HYDRAULIC DESIGN PARAMETERS						
Pump Design Point, Flow (gpm)/Head (ft.)	88,500/264	88,500/264	88,500/264	88,500/264	88,500/264	88,500/264
Mechanical Design Flow, gpm	101,800	101,800	101,800	101,800	101,800	101,800
Minimum Measured Flow, gpm total	264,200[6]	264,200[6]	264,200[6]	264,200[6]	264,200[6]	264,200[6]
Best Estimate Flow, gpm	96,100[7]	93,300[7]	92,100[7]	96,100[7]	93,300[7]	92,100[7]

Notes:

(1) V5 fuel features; RTN, IFMs, DFBN, Zirlo grids, RTDP, AB & IFBAs optional; Zirlo cladding.

(2) Core bypass flow includes 2.0 percent due to thimble plug removal and 0.6 percent due to IFMs.

(3) If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 817 psia, steam temepratture of 520.6°F, and steam flow of 12.26x10^6 lb/hr is assumed. This is to cover the possibility that the plant could operate with better than expected SG performance with the replacement SGs.

(4) 19 psi SG internal pressure drop incorporated.

(5) Program covers 15 percent average and 20 percent peak SGTP.

(6) MMF based on a 2.4 percent flow measurement uncertainty; analyses cover range of MMF from 263,400 gpm (2.1 percent) to 264,200 gpm (2.4 percent).

(7) BEF is conservatively low based on thimble plugs installed since SNC will operate with them installed in the future.

(8) For analysis purposes, a minimum steam pressure of 690 psia for 15 percent SGTP and 675 psia for 20 percent SGTP can be assumed since the plant cannot operate at steam pressures this low during full power.

4.0 NSSS ACCIDENT ANALYSES

This section provides the results of the analyses and/or evaluations that were completed for the NSSS accident analyses in support of the RSG Program. Section 4.0.1 first gives a summary of the initial condition instrumentation uncertainty analysis results, which were used in the accident analyses. The accident analysis areas covered within this section include: best estimate large break LOCA (BE LBLOCA) and small break LOCA (SBLOCA), non-LOCA transients, steam generator tube rupture (SGTR), LOCA and main steamline break mass and energy releases, and protection system setpoints.

The detailed results and conclusions of each analysis are presented within each subsection.

4.0.1 Initial Condition Uncertainties

This section addresses the initial condition uncertainties used in the accident analyses that were reanalyzed or evaluated for Farley Units 1 and 2 to support the RSG Program. The uncertainties are included in the non-LOCA analyses, large and small break LOCAs, LOCA forces (provided as input to component structural analyses), SGTR, and main steamline break and LOCA mass and energy releases (provided as input to the containment integrity analyses).

Six parameters include initial condition steady-state uncertainties that are explicitly modeled in various transient and accident analyses.

1. Pressurizer Pressure (automatic pressurizer pressure control system and narrow range pressure indications)

2. Reactor Coolant System (RCS) T_{avg} (automatic reactor control system and T_{avg} indications)

3. Reactor Power (daily calorimetric power measurement used to normalize power range instruments)

4. RCS Total Flow (plant computer measurement based on RCS loop flows normalized to once per fuel cycle calorimetric-based RCS flow measurement, or RCS loop flows normalized to past calorimetric-based RCS flow measurement, i.e., elbow tap total flow measurement method)

5. Steam Generator Water Level (automatic steam generator water level control system and narrow range hot calibrated level indications). This value changes from the ± 7 percent span (random) with a -5 percent span (bias) for the power uprate to ± 6 percent span for the RSG.

6. Pressurizer Water Level (automatic pressurizer water level control system and hot-calibrated level indications)

The uncertainty calculations have been performed for Farley Units 1 and 2 based on the plant-specific instrumentation and calibration methods. Table 4.0.1-1 summarizes the results and the uncertainties used in the Farley transient and accident analyses.

Table 4.0.1-1
Farley RSG Program Transient and Accident Analyses Results and Uncertainties

Parameter	Calculated Uncertainty	Uncertainty Allowance Used in Safety Analysis
Pressurizer Pressure	±48.1 psi (random) -1.5 psi (bias)	±50.0 psi (random)
T_{avg}	±3.7°F (random) -1.0°F (bias)	±6.0°F (includes cold leg streaming bias of -1.0°F)
Power	±1.1% RTP (random)	±2.0% RTP (random)
RCS Flow (once per fuel cycle normalization)	±1.9% TDF (random)	±2.1% to ±2.4% TDF (random)[1]
RCS Flow (past fuel cycle normalization)	±2.3% TDF (random)	±2.1% to ±2.4% TDF (random)[1]
Steam Generator Water Level	±5.4% span (random)	±6.0% span (random)
Pressurizer Water Level	±4.1% span (random) +0.6% span (bias)	±5.0% (random)

Notes:

(1) Applicable for range of ±2.1% to ±2.4%.

4.1 LOCA TRANSIENTS

4.1.1 Best Estimate Large Break LOCA

4.1.1.1 Introduction

The purpose of this section is to evaluate the impact of replacing Model 51 with Model 54F steam generators at Farley Units 1 and 2 on the results of the BE LBLOCA analysis at uprated conditions.

The approved Westinghouse BE LBLOCA methodology (References 1 and 2) was used to analyze Farley Units 1 and 2 at uprated power conditions. This analysis includes the complete application of the best estimate (BE) methodology for the limiting unit. A plant-specific WCOBRA/TRAC model was developed, and explicit treatment of the uncertainties in the required reactor parameters was included. Numerous plant calculations were performed, as specified by the BE methodology. From these sensitivity studies, response surfaces were fit and used to obtain predictions of the pressurized water reactor (PWR) response to variations in the dominant model and plant inputs. A Monte Carlo technique was used to sample from the uncertainty distribution for the various model and plant parameters. A large number of samplings was used to generate an overall peak clad temperature (PCT) uncertainty distribution, from which the 50th and 95th percentile PCT values were obtained.

For the RSG Program, an analysis of the effect of the Model 54F steam generator on the BE LBLOCA results is performed. Since the Model 54F is similar in design to the Model 51 steam generator, the impact on the BE LBLOCA results is expected to be small. In accordance with the approved methodology (Reference 2, Section 28-3-1), for small changes to a plant analysis, a reanalysis can be performed utilizing a subset of the original run matrix to establish the effect on PCT. This approach involves reanalysis of a select group of WCOBRA/TRAC calculations from the Power Uprate Project, incorporating the physical dimension changes required to model the Model 54F steam generator. The results of these calculations are incorporated into the Monte Carlo simulation to calculate the final estimate of the 95th percentile PCT. This estimate of the 95th percentile PCT becomes the new licensing basis for Farley Units 1 and 2 with Model 54F steam generators.

In the following section, each step of the BE LBLOCA methodology is discussed with regards to the changes, if any, made to incorporate the RSGs in the Farley design.

4.1.1.2 Description of Methodology for Evaluation of RSG Impact on BE LBLOCA

The thermal-hydraulic computer code approved for the calculation of fluid and thermal conditions in the PWR during a LBLOCA is WCOBRA/TRAC, MOD7A, Revision 1 (Reference 2). Since its approval, the code has been upgraded to Revision 4, as described in Reference 3. Revision 4 has been used for the analysis of the RSG for Farley Units 1 and 2. The material properties for the loop components were modified to incorporate Alloy 690 properties for the Model 54F steam generator.

The evaluation of the impact of the Model 54F RSG on the Farley BE uprate analysis is done following the approved methodology for the evaluation of the impact of small changes to the analysis conditions. For each of the steps required in the BE methodology, a discussion is included below to show how it is handled for the RSG.

1. Plant Model Development

   The reactor vessel model for the RSG Program is identical to that used in the uprate analysis. The majority of the one-dimensional loop model components also remain identical to that used in the uprate analysis, with the exception of the steam generator. The Model 54F steam generator is explicitly modeled for this analysis effort. The Model 51 steam generator used in the uprate analysis is replaced by the Model 54F steam generator. Table 2.1-1 includes the major steam generator differences that impact the LBLOCA modeling.

   The increased flow area afforded by the increased number of tubes is the most significant design difference between the steam generators that impacts the LBLOCA. This results in a larger flow area for the same percentage of tube plugging. Thus, for the Model 54F steam generator with 20 percent tube plugging, the primary flow area is about six percent larger than the Model 51 steam generator with the same percentage tube plugging. This means that incorporation of the Model 54F into the LBLOCA model would be expected to have a similar effect to reduced tube plugging in the Model 51 uprate analysis. As shown in the uprate analysis, the PCT sensitivity to changes in SGTP is not large (less than three degrees per one percent SGTP), so the impact of a small increase in flow area for the Model 54F steam generator is not expected to yield a large difference in the behavior of the transients performed for the uprate analysis.

   The Farley uprate analysis covers both Unit 1 and Unit 2. Unit 1 is an upflow barrel-baffle design and Unit 2 is a downflow design. Sensitivity studies performed for the Power Uprate Project show that the Unit 2 PCT is 70°F greater than Unit 1, and is, therefore, the limiting plant configuration. Incorporating the RSG into each unit would be expected to have similar effects on the transient, such that Unit 2 PCT will remain the limiting plant configuration. Therefore, Unit 2 is analyzed for the RSG Program and the results obtained from the Unit 2 RSG analysis will also be applicable to Unit 1.

2. Determination of Reference Transient Conditions

   The same operating range is chosen for the RSG conditions as was utilized in the Power Uprate Project. This eliminates the need to redetermine the limiting plant operating conditions to use in the reference transient. The only exception is the SGTP sensitivity. Since this is a replacement steam generator, both the 0 percent and 20 percent SGTP cases are analyzed with the reference split transient to verify the limiting plant condition and lend support to the initial assumption that incorporating the RSG is a small change.

   The initial reference transient is a double-ended cold leg guillotine (DECLG) break. In the Farley uprate program, the DECLG transient was used as the reference transient for all of the confirmatory calculations (e.g., offsite power availability), as prescribed by the approved methodology. This remains valid for the RSG Program. Later in the uprate program it was determined that the limiting transient was a split break by a large PCT margin (75°F). In keeping with the approved methodology, it is not necessary to re-determine limiting conditions if the limiting break type changes. Thus, for the RSG Program, the determination of limiting plant conditions is left unchanged and conditions specified for the reference transient remain the same.

3. PWR Sensitivity Calculations

In the BE methodology, a series of PWR transients are performed in which the initial fluid conditions and boundary conditions are ranged around the nominal conditions used in the reference transient. The results of these calculations form the basis for the determination of the initial condition bias and uncertainty. Since the ranging of the initial fluid conditions and boundary conditions are unchanged for the RSG, this step has not been repeated for the RSG Program.

Next, a series of transients are performed that vary the power distribution. The results of these calculations form the basis for the determination of the power distribution bias and uncertainty. Since the parameters varied for the power distribution bias and uncertainty calculations are not changed, this step has not been repeated for the RSG Program.

Next, a series of transients are performed that vary models that effect the overall system response ("global" models) and local fuel rod response ("local" models). The results of these calculations form the basis for the determination of the global model bias and uncertainty. In the Farley power uprate analysis, these global model transients were initially based on the DECLG reference transient. Since the DECLG transient is not limiting, this step has not been repeated for the RSG Program.

Later, once the response surfaces have been derived (Step 4), an initial determination of the limiting break type is performed (Step 5). For the Farley Power Uprate Project, this initial determination showed the split break to be limiting. Since the steps up to this point are unchanged, this step has not been repeated for the RSG Program.

4. Response Surface Calculations

Regression analyses are performed to derive PCT response surfaces from the results of the power distribution run matrix and the global model run matrix. The results of the initial conditions run matrix are used to generate a PCT uncertainty distribution. Since none of the analyses forming the basis for the response surfaces have been repeated, there is no change in the response surfaces from the Farley power uprate analysis for the RSG Program.

5. Uncertainty Evaluation

The total PCT uncertainty from the initial conditions, power distribution, and model calculations is derived using the approved methodology (References 1 and 2). The uncertainty calculations assume certain plant operating ranges, which may be varied depending on the results obtained. These uncertainties are then combined to determine the initial estimate of the total PCT uncertainty distribution for the DECLG break and the limiting split break. The results of these initial estimates of the total PCT uncertainty are compared to determine the limiting break type. For the Farley Power Uprate Project, the initial uncertainty estimates resulted in the split break being limiting. Therefore, an additional set of split transients were performed to determine the global model bias and uncertainty for split breaks. The estimate of the PCT uncertainty distribution was then repeated, and the split break remained limiting.

To be consistent, this portion of the Farley power uprate analysis was also left unchanged for the RSG Program. To reanalyze the split break global model run matrix would put the split break global model bias and uncertainties on an inconsistent basis with the rest of the response surfaces and uncertainties. This decision is supported by an assessment of the effect of the RSG resistance on the nominal break flow flowpath resistance ratio (R_{BR}), which is the parameter reflected in the global model run matrix that could be affected by the RSG. The change in the nominal value is small relative to the range already analyzed and reflected in the global model bias and uncertainty for split breaks.

To verify that the reference split break size remains limiting, two additional split break cases are analyzed that incorporate the RSG, one with reduced, and one with increased break size. This confirms that the limiting break size remains the same, and also supports the assumption that the global model response is not strongly affected by the RSG.

Instead of changing the response surfaces, the RSG is incorporated into the final series of runs (the superposition cases). In this step, an additional series of runs is made to quantify the bias and uncertainty due to assuming that the above three uncertainty categories (initial conditions, power distributions, and global models/break type) are independent. The superposition cases combine several parameters that were previously assumed independent. The superposition runs for the uprate analysis used the split break as a basis, and this is also done for the RSG cases. Incorporating the RSG in this step is done without impacting the response surfaces and initial uncertainty estimates. The final PCT uncertainty distribution is then calculated for the limiting break type (split), and the 95th percentile PCT is determined.

6. Plant Operating Range

The plant operating range over which the uncertainty evaluation applies is defined. Depending on the results obtained in the above uncertainty evaluation, this range may be the desired range established in Step 2, or may be narrower for some parameters to gain additional margin. For the RSG analysis, the plant operating range is unchanged from that determined for the uprate analysis.

Thus, in the BE methodology, there are three major uncertainty categories or elements:

1. Initial condition bias and uncertainty
2. Power distribution bias and uncertainty
3. Model bias and uncertainty

Conceptually, these elements may be assumed to affect the reference transient PCT as shown below.

$$PCT_i = PCT_{REF,i} + \Delta PCT_{IC,i} + \Delta PCT_{PD,i} + \Delta PCT_{MOD,i} \qquad \text{(Equation 4.1.1-1)}$$

where:

$PCT_{REF,i}$ = **Reference transient PCT:** The reference transient PCT is calculated using WCOBRA/TRAC at the conditions identified in Table 4.1.1-1 with the changes outlined in the power uprate analysis, for blowdown (i = 1), first reflood (i = 2) and second reflood (i = 3). The same conditions are utilized for the RSG analysis.

$\Delta PCT_{IC,i}$ = **Initial condition bias and uncertainty:** This bias is the difference between the reference transient PCT, which assumes several nominal or average initial conditions, and the average PCT, taking into account all possible values of the initial conditions. This bias takes into account plant variations that have a relatively small effect on PCT. The elements that make up this bias and its uncertainty are plant-specific.

$\Delta PCT_{PD,i}$ = **Power distribution bias and uncertainty:** This bias is the difference between the reference transient PCT, which assumes a nominal power distribution, and the average PCT, taking into account all possible power distributions during normal plant operation. Elements that contribute to the uncertainty of this bias are calculational uncertainties, and variations due to transient operation of the reactor.

$\Delta PCT_{MOD,i}$ = **Model bias and uncertainty:** This component accounts for uncertainties in the ability of the WCOBRA/TRAC code to accurately predict important phenomena that affect the overall system response ("global" models) and the local fuel rod response ("local" models). The code and model bias is the difference between the reference transient PCT, which assumes nominal values for the global and local models, and the average PCT, taking into account all possible values of global and local models.

The separability of the uncertainty components in the manner described above is an approximation, since the parameters in each element may be affected by parameters in other elements. The bias and uncertainty associated with this assumption is quantified as part of the overall uncertainty methodology with the superposition correction and included in the final estimates of the 95th percentile PCT.

4.1.1.3 WCOBRA/TRAC Model for Farley Units 1 and 2

Step 1 discussed in the previous section is the development of a plant model. The vessel noding diagrams for Farley Units 1 and 2 are shown in Figures 4.1.1-1 and 4.1.1-2. These are the same noding used for the uprate program. Figure 4.1.1-3 shows the one-dimensional component layout for the loops. Within the channels and components, additional subdivisions into cells are present.

4.1.1.4 Farley Unit 2 Transient Results

As discussed in Section 4.1.1.2, the Model 54F steam generator is incorporated into the reference split transient (discharge coefficient, C_D=1.0) to determine its impact on the results. Table 4.1.1-2 shows the key reference transient assumptions from the uprate analysis used for the RSG analysis. These values are unchanged from the values used in the uprate reference split break.

4.1.1.4.1 Unit 2 Reference Split Transient Description

The Unit 2 reference transient determined in the Power Uprate Project is a C_D=1.0 cold leg split break with the conditions listed in Table 4.1.1-1. Since many of these parameters are at their bounded values, the calculated results are a conservative representation of the response to a LBLOCA.

The LOCA transient can be divided into time periods in which specific phenomena are occurring. A convenient way to divide the transient is in terms of the various heatup and cooldown transients that the hot assembly undergoes. For each of these phases, specific phenomena and heat transfer regimes are important, as discussed below. Results are shown in Figures 4.1.1-4 to 4.1.1-17, beginning with the PCT transient in Figure 4.1.1-4. In these figures, the transient starts at 0 seconds.

CRITICAL HEAT FLUX (CHF) PHASE

Immediately following the cold leg rupture, the break flowrates are subcooled and high. The regions of the RCS with the hottest initial temperatures (core, upper plenum, upper head, and hot legs) begin to flash to steam within the first 0.5 seconds following the break. Flow in the core reverses, and the fuel rods begin to go through departure from nucleate boiling (DNB). Voiding in the core also causes the fission power to drop rapidly. The discharge flowrates decrease sharply as the break flow becomes two-phase (Figure 4.1.1-5). This phase is terminated when the water in the lower plenum and downcomer (DC) begin to flash.

UPWARD CORE FLOW PHASE

Flashing in the lower plenum and pumped flow supplied by the intact loops re-establishes upward core flow for a brief period of time, from 3 to 5 seconds after the break (Figure 4.1.1-6). This phase ends as the lower plenum mass is depleted, the loops become two-phase, and the pump head degrades because of two-phase conditions (Figure 4.1.1-7).

DOWNWARD CORE FLOW PHASE

Downward flow into the core increases as the pump head continues to be degraded and upward flow in the DC is firmly established (Figure 4.1.1-8).

Due to the downflow during this phase, the cladding temperature is turned around at about 15 seconds after the initiation of the transient, resulting in a blowdown PCT of 1591°F. The accumulators on the intact loops begin to inject at 14 seconds after the break (Figure 4.1.1-9). Initially, the injected water is bypassed around the DC and out of the break. As the system pressure continues to fall (Figure 4.1.1-10), the break flow, and consequently the core flow, are reduced. The vessel pressure reaches the containment pressure at the end of this phase, which occurs about 32 seconds after the initiation of the transient. The core begins to heat up as the system reaches containment pressure and the vessel begins to fill with emergency core cooling system (ECCS) water.

REFILL PHASE

When the steam flow in the downcomer is sufficiently reduced, the cold ECCS water begins to penetrate the DC (Figure 4.1.1-11) and refill the lower plenum. The refill period is characterized by a rapid increase in the lower plenum liquid level and the vessel fluid mass (Figures 4.1.1-12 and 4.1.1-13). In this period, the cladding temperature at all elevations increases rapidly due to the lack of liquid and steam flow in the core region and resulting poor cooling (Figure 4.1.1-4). This phase ends when the lower plenum fills with water (Figure 4.1.1-12) and the ECCS water enters the core (bottom of core recovery). This initiates the reflood phase, where entrainment begins, with a resulting improvement in heat transfer.

REFLOOD PHASE

At the beginning of this phase, the accumulators empty (Figure 4.1.1-9) and nitrogen enters the system, which causes a surge of water into the core (Figure 4.1.1-14) and a temporary cooldown. The early part of this period is characterized by a significant vapor generation as the lower elevations of the core quench. This temporarily increases the core pressure, reversing the core inlet flow. As the steam generated in the core is vented through the loops and the DC level rises further, the DC pressure increases above the core pressure, and positive core flow is re-established. The resulting core/DC level oscillations can be seen in the core and DC liquid level plots (Figures 4.1.1-14 and 4.1.1-11). The first reflood PCT for the reference split break is 1811°F, reached at the 9.7-foot elevation on the hot rod, about 105 seconds after the break. At approximately 120 seconds, ECCS water accumulated in the lower plenum starts to boil, causing a reduction in the core and DC liquid levels and the vessel mass (Figure 4.1.1-13), as the two-phase level swell pushes water out the break (Figure 4.1.1-5). This causes a second heat-up of the core, resulting in a second reflood PCT of 1796°F at the 10.5-ft elevation about 225 seconds after the break. The cold water from the pumped safety injection (Figure 4.1.1-15) eventually collapses the voids sufficiently for the DC to resume refilling (Figure 4.1.1-11) and quenching the lower elevations of the fuel rods (Figure 4.1.1-16).

4.1.1.4.1.1 Comparison of Reference Split Transients

Figure 4.1.1-17 compares the PCT transient between the reference split break transients for the RSG and the Model 51 steam generator. The RSG transient shows little difference in thermal-hydraulic characteristics from the Model 51 steam generator. This is confirmed in Figure 4.1.1-18, which shows the average core liquid level during the transient. The core liquid levels show that the timing of the core draining and refilling are virtually identical. The resulting limiting first reflood PCT for the RSG is a 5°F reduction compared to the Model 51 steam generator transient. This comparison confirms the assumption that the RSG would have a small effect on the reference transient.

4.1.1.4.2 Unit 2 Confirmatory Studies for RSG

Several sensitivity calculations are performed with the RSG split transient to further confirm the assumptions made about the effect of the RSG on the transient.

A steam generator sensitivity study is performed where the tube plugging is reduced from 20 percent in the reference split to 0 percent. The results of the SGTP analysis compared to the reference split are shown in Table 4.1.1-2. The results indicate that 20 percent SGTP remains limiting for the RSG, as it was for the uprate analysis.

A split break spectrum is performed where the split break sizes on either side of the limiting split are repeated for the RSG. This is done to ensure that the change in steam generator flow resistance will not significantly change the dynamics of the transient such that the limiting break size shifts. Table 4.1.1-2 shows the result of these additional split breaks. This break spectrum shows that the relative results of the change in break size remains the same as the uprate analysis, with C_D=1.0 remaining the limiting split.

The results for these sensitivity studies are summarized in Table 4.1.1-2. The results of these analyses lead to the following conclusions:

1. The Model 54F RSG results in a reduction in PCT for the reference split break due to the increase in flow area afforded by the additional number of tubes. This increase in flow area behaves similarly to a reduction in SGTP level.

2. A cold leg split break with a discharge coefficient of 1.0 remains the limiting reference transient for Unit 2. This reinforces the assumption that incorporating the RSG into the Farley model will not significantly alter the relative results of any of the uprate transient response surfaces. This split break then becomes the reference transient for the final determination of uncertainties.

4.1.1.4.3 Unit 2 Initial Conditions Sensitivity Studies

As previously discussed in Section 4.1.1.2, the initial condition sensitivity studies for the Power Uprate Project are based on the DECLG reference transient at a given set of initial fluid conditions and boundary conditions. These calculations analyzed key initial plant conditions over their expected range of operation. These studies include effects of ranging T_{avg}, RCS pressure, and ECCS temperatures, pressures, and volumes. The calculated results were used to develop initial condition uncertainty distributions for the blowdown, first, and second reflood peaks. These distributions were then used in the uncertainty evaluation, and to predict the PCT uncertainty component resulting from initial conditions uncertainty, $\Delta PCT_{IC,i}$.

Since the ranging of the initial fluid conditions and boundary conditions are unchanged for the RSG, this step has not been repeated for the RSG Program.

4.1.1.4.4 Unit 2 Power Distribution Sensitivity Studies

Several DECLG calculations were performed for the Power Uprate Project to evaluate the effect of power distribution on the calculated LOCA transient. The power distribution attributes analyzed are the peak linear heat rate relative to the core average, the maximum relative rod power, the relative power in the bottom third of the core, and the relative power in the middle third of the core. The choice of these variables and their ranges are described and justified in Reference 2.

The results obtained using a run matrix developed to vary the power distribution attributes singly, and in combination, indicate that power distributions with peak powers shifted towards the top of the core, produce higher PCTs.

The DECLG calculated results were used to develop response surfaces, as described in Step 4 of Section 4.1.1.2, which could be used to predict the change in PCT for various changes in the power distributions, and for the blowdown, first and second reflood peaks. The response surfaces were then used in the uprate uncertainty evaluation to predict the PCT uncertainty component resulting from uncertainties in power distribution parameters, $\Delta PCT_{PD,i}$.

Since the parameters varied for the power distribution bias and uncertainty calculations are not changed for the RSG Program, this step has not been repeated for the RSG Program.

4.1.1.4.5 Unit 2 Global Model Sensitivity Studies

For the Power Uprate Project, several calculations were performed to evaluate the effects of broken loop resistance, break discharge coefficient, and condensation rate on the PCT for the double-ended guillotine break. As in the power distribution study, these parameters are varied singly and in combination to obtain a database that could be used for response surface generation. The run matrix and ranges of the break flow parameters are described in Reference 2. The limiting split break size is also identified using the approved methodology (References 1 and 2).

The results of these studies indicate that the uncertainty distribution for a split break with a C_D of 1.0 is more limiting than the uncertainty distribution for a DECLG. This requires that the effect of broken loop resistance and condensation must be re-evaluated for the limiting split break size. The calculated results from these additional split breaks are included in the uprate analysis.

The calculated results are used to develop response surfaces as described in Section 4.1.1.2, which could be used to predict the change in PCT for various changes in the flow conditions. These are then used in the uncertainty evaluation to predict the PCT uncertainty component resulting from uncertainties in global model parameters, $\Delta PCT_{MOD,i}$.

To be consistent, this portion of the Farley power uprate analysis is not repeated for the RSG Program. To reanalyze the split break global model run matrix would put the split break global model bias and uncertainties on an inconsistent basis with the rest of the response surfaces and uncertainties. The RSG changes will be made later in the superposition runs, which test the effect of the RSG on the selected global model parameter changes.

4.1.1.5 Uncertainty Evaluation and Results

The fifth step described in Section 4.1.1.2 is the evaluation of uncertainty. The equation describing the elements of uncertainty is shown as Equation 4.1.1-1. Each element of uncertainty is initially considered to be independent of the other. Each bias component is considered a random variable, whose uncertainty and distribution are obtained either directly, or are obtained from the uncertainty of the parameters of which the bias is a function. For example, $\Delta PCT_{PD,i}$ is a function of F_Q, $F_{\Delta H}$, P_{BOT} and P_{MID}. Its distribution is obtained by sampling the plant F_Q, $F_{\Delta H}$, P_{BOT} and P_{MID} distributions and using a response surface to calculate $\Delta PCT_{PD,i}$. Since PCT_i is the sum of these biases, it also becomes a random variable. Separate initial PCT frequency distributions are constructed as follows for the DECLG and the limiting split break size:

1. Generate a random value of each ΔPCT_i element.
2. Calculate the resulting PCT using Equation 4.1.1-1.
3. Repeat the process many times to generate a histogram of PCTs.

For Farley Units 1 and 2 at uprated conditions, the results of this assessment show the split break to potentially be limiting. Additional split break calculations are performed, a more detailed description of $\Delta PCT_{MOD,i}$ developed, and Steps 1 through 3 repeated for the limiting split break size. This analysis confirms the split break to be the limiting break type.

A final verification step is performed, in which additional calculations (known as "superposition" calculations), are made with WCOBRA/TRAC, simultaneously varying several parameters which were previously assumed independent (for example, power distributions and models). Predictions using Equation 4.1.1-1 are compared to this data, and additional biases and uncertainties applied.

For the RSG analysis, all of the superposition cases previously performed for the Power Uprate Project are reanalyzed, incorporating the Model 54F RSG. These cases include parameters which were not varied in combination in the initial steps; for example, a WCOBRA/TRAC calculation with the power shape 3 (PS3) and low average RCS temperature could be performed. The same parameters used in the Farley uprate analysis are used for these RSG superposition runs, since all of the sensitivity studies used in the selection of these parameters have not been changed for the RSG Program.

The results of these calculations are used in the final Monte Carlo evaluation to determine the estimate of the 95th percentile PCT.

The estimate of the PCT at 95 percent probability is determined by finding the PCT below which 95 percent of the calculated PCTs reside. This estimate is the licensing basis PCT, under the revised ECCS rule.

The results for Farley Unit 2 with Model 54F RSG are given in Table 4.1.1-3. As expected, the difference between the 95 percent value and the average value increases with increasing time, due to propagation of uncertainties. It should also be noted that the average value of PCT is well below the reference case values used for both the initial conditions and response surface studies. This indicates that the variations predicted by the response surfaces are conservative.

A separate analysis to assess the effect of WCOBRA/TRAC MOD7A Revision 4 code changes on the approved Farley Units 1 and 2 Power Uprate Project analysis resulted in a 95th percentile PCT of 2060°F for the first reflood PCT. Comparison of these results to the RSG results, presented in Table 4.1.1-3, show that the PCT effect attributed to the RSG is a 4°F reduction in the licensing basis PCT.

4.1.1.5.1 Additional Evaluations

For changes in conditions that are expected to not significantly affect the thermal-hydraulic transient, incorporation of the change into the limiting break type reference transient (DECLG or split break) yields an important indication of the effect on the results. The desired change in conditions can be incorporated into the reference transient, and a comparison made between the new case and the original transient. If the new transient shows similar thermal-hydraulic response, an estimate of the effect of this change on the 95th percentile PCT could be issued based on the reference transient PCT results. Likewise, if a sensitivity to a change in a given condition has previously been evaluated for a similar plant type (three- or four-loop), and similar reference transient (DECLG or split), the PCT effect of the change to the reference transient could be used to issue an estimated PCT impact on the 95th percentile PCT for another plant.

An evaluation of the impact of the increase in spray flows and reduction in spray delay time on the containment pressure transient for Farley resulted in a maximum reduction in pressure of 1 psi. To evaluate the impact of this change on the reference split break transient, an appropriate sensitivity study was required. A sensitivity study to a 2.7 psi reduction in containment pressure performed with WCOBRA/TRAC on another three-loop plant that has the split break as the limiting reference transient was found. This sensitivity to containment pressure change showed no significant effect on the thermal-hydraulic transient. Using this sensitivity study, the impact of the gradual reduction in containment pressure is estimated to yield a 9°F increase in first reflood PCT and a 1°F increase in second reflood PCT for the Farley reference transient. This penalty is then applied to the limiting 95th percentile PCT as an estimate of the impact of this change. Thus, the limiting 95th percentile PCT for the BE LBLOCA WCOBRA/TRAC analysis for the RSG, including the estimated impact of the increase in containment spray flows, becomes 2056° + 9° = 2065°F.

Future evaluation of other small changes in plant conditions will follow a similar method to that described above, depending on the magnitude of the change and its estimated impact on the thermal-hydraulics on the reference transient. The desired change in conditions will be incorporated into the reference transient to determine if the resulting transient shows similar thermal-hydraulic response to the original. If the impact on the reference transient is small, the resulting change in PCT can be applied to the 95th percentile PCT as an estimate of the effect of the change in plant conditions. If a similar plant sensitivity is available, it can be used to estimate the impact on the 95th percentile PCT for Farley in the same fashion.

4.1.1.6 Acceptance Criteria

It must be demonstrated that there is a high probability that the limits set forth by 10 CFR 50.46 (Reference 4) will not be exceeded. The demonstration that these limits are met for Farley Units 1 and 2 are as follows:

1. There is a high level of probability that the PCT shall not exceed 2200°F. The results in Table 4.1.1-3 indicate that this limit has been met.

2. The maximum calculated total cladding oxidation shall nowhere exceed 0.17 times the total cladding thickness before oxidation (17 percent). The approved methodology assesses this requirement using a plant-specific transient that has a PCT in excess of the estimated 95th percentile PCT. Based on the plant specific calculation shown in Table 4.1.1-3, a maximum total oxidation value of 12 percent is calculated, which meets the regulatory limit. ' e the plant-specific transient used for the Farley Power Uprate Project exceeds the estimated 95th percentile PCT for the RSG Program, there is no need to reassess this criteria for the RSG. The uprate analysis results remain valid for the Model 54F RSG.

3. 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 were to react. The total amount of hydrogen generated, based on the plant specific calculation shown in Table 4.1.1-3, is 0.006 times the maximum theoretical amount, which meets the regulatory limit. Since the transient used to evaluate this criteria bounds the RSG analysis, there is no need to reassess this criteria for the RSG. The uprate analysis results remain valid for the Model 54F RSG.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling. This requirement is met by demonstrating that the PCT does not exceed 2200°F, and the seismic and LOCA forces are not sufficient to distort the fuel assemblies to the extent that the

core cannot be cooled. The approved methodology (References 1 and 2) specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends to in-board assemblies (i.e., assemblies beyond the 28 peripheral assemblies modeled in the low-power channel). Fuel assembly structural analyses performed for the Power Uprate Project indicate that this condition does not occur. These structural analyses are not affected by the Farley RSG; therefore, this regulatory limit is met for the RSG.

5. 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. While WCOBRA/TRAC is typically not run past full core quench, all calculations are run well past PCT turnaround and past the point where increasing vessel inventories are calculated. The conditions at the end of the WCOBRA/TRAC calculations indicate that the transition to long-term cooling is under way even before the entire core is quenched.

4.1.1.7 Conclusions

The expected PCT and its uncertainty are valid for a range of plant operating conditions. Consistent with the approved BE LBLOCA methodology, many parameters in the base case calculation are at nominal values. The range of variation of the operating parameters has been accounted for in the estimated PCT uncertainty. Table 4.1.1-4 summarizes the operating ranges for Farley Units 1 and 2. Note that Figure 4.1.1-20 describes the axial power distribution limits that must be adhered to for each fuel cycle. If operation is maintained within these ranges, based on the Farley RSG analyses and sensitivity studies presented herein, it is concluded that the BE LBLOCA analyses performed for the Power Uprate Project remain valid for Farley Units 1 and 2 at uprated conditions with Model 54F steam generators.

4.1.1.8 References

1. Letter, R. C. Jones (USNRC) to N. J. Liparulo (W), *Acceptance for Referencing of the Topical Report WCAP-12945 (P), Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Analysis*, June 28, 1996

2. *Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Accident Analysis*, WCAP-12945-P-A (Proprietary) and WCAP-14747 (Non-Proprietary), Volume I (Revision 2) and Volumes II-V (Revision 1), March 1998

3. Letter, H. A. Sepp (W) to T. E. Collins (USNRC), *1997 Annual Notification of Changes to the Westinghouse Small Break LOCA and Large Break LOCA ECCS Evaluation Models, Pursuant to 10 CFR 50.46 (a)(3)(ii)*, NSD-NRC-98-5575, April 8, 1998

4. *Acceptance Criteria for Emergency Cooling Systems for Light Water Cooled Nuclear Power Plants, Federal Register 39, (3)*, 10 CFR Part 50, December 1973

Table 4.1.1-1
Key LOCA Parameters and Reference Transient Assumptions (Units 1 and 2)

Parameter	Reference Transient	Uncertainty or Bias
1.0 Plant Physical Description		
a. Dimensions	Nominal	ΔPCT_{MOD} [1]
b. Flow resistance	Nominal	ΔPCT_{MOD}
c. Pressurizer location	Adjacent to broken loop	Bounded
d. Hot assembly location	Limiting location	Bounded
e. Hot assembly type	17x17 V5 w/ZIRLO™ Clad mesh assembly	Bounded
f. Steam generator tube plugging level	High (20%)	Bounded
2.0 Plant Initial Operating Conditions		
2.1 Reactor Power		
a. Core average linear heat rate (AFLUX)[3]	Nominal - Based on 100% of uprated power (2775 MWt)	ΔPCT_{PD} [2]
b. Peak linear heat rate (PLHR)[3]	Derived from Tech Spec limit of 2.5 and maximum baseload FQ	ΔPCT_{PD}
c. Hot rod average linear heat rate (HRFLUX)[3]	Derived from $F_{\Delta H} = 1.7$	
d. Hot assembly average heat rate (HAFLUX)	HRFLUX/1.04	ΔPCT_{PD}
e. Hot assembly peak heat rate (HAPHR)	PLHR/1.04	ΔPCT_{PD}
f. Axial power distribution (PBOT, PMID)	Figure 4.1.1-20	ΔPCT_{PD}

Table 4.1.1-1 (Cont.)
Key LOCA Parameters and Reference Transient Assumptions (Units 1 and 2)

Parameter			Reference Transient	Uncertainty or Bias
	g.	Low power region relative power (PLOW)	0.2	Bounded
	h.	Hot assembly burnup	Beginning of Life	Bounded
	i.	Prior operating history	Equilibrium decay heat	Bounded
	j.	Moderator Temperature Coefficient (MTC)	≤ 0 at Max full power	Bounded
	k.	Hot Full Power (HFP) boron	800 PPM	Generic
2.2	Fluid Conditions			
	a.	T_{avg}	Low $T_{avg} = 567.2°F$	Bounded; Uncertainties in ΔPCT_{IC} (4)
	b.	Pressurizer pressure	Nominal (2250 psia)	ΔPCT_{IC}
	c.	Loop flow	86,000 gpm	ΔPCT_{MOD}
	d.	T_{UH}	T_{HOT}	0
	e.	Pressurizer level	Nominal (43.8%)	0
	f.	Accumulator temperature	Nominal (105°F)	ΔPCT_{IC}
	g.	Accumulator pressure	Nominal (640 psia)	ΔPCT_{IC}
	h.	Accumulator volume	Nominal (980 ft^3)	ΔPCT_{IC}
	i.	Accumulator f(L/D)	Nominal	ΔPCT_{IC}
	j.	ECCS boron	Minimum	Bounded

Table 4.1.1-1 (Cont.)
Key LOCA Parameters and Reference Transient Assumptions (Units 1 and 2)

Parameter			Reference Transient	Uncertainty or Bias
3.0	**Accident Boundary Conditions**			
	a.	Break location	Cold leg	Bounded
	b.	Break type	Guillotine[5]	ΔPCT_{MOD}
	c.	Break size	Nominal (cold leg area)	ΔPCT_{MOD}
	d.	Offsite power	On (RCPs running)	Bounded
	e.	Safety injection flow	Minimum	Bounded
	f.	Safety injection temperature	Nominal (85°F)	ΔPCT_{IC}
	g.	Safety injection delay	Max delay (12 sec)	Bounded
	h.	Containment pressure	Bounded - Based on minimum containment pressure of 14.7 psia. Bounding pressure curve (Figure 4.1.1-19) is based on COCO containment calculation using conditions supplied in Table 4.1.1-5.	Bounded
	i.	Single failure	ECCS: Loss of 1 SI Train Containment press: all trains operational	Bounded
	j.	Control rod drop time	No control rods	Bounded
4.0	**Model Parameters**			
	a.	Critical flow	Nominal ($C_D = 1.0$)	ΔPCT_{MOD}
	b.	Resistance uncertainties in broken loop	Nominal (as coded)	ΔPCT_{MOD}

Table 4.1.1-1 (Cont.)
Key LOCA Parameters and Reference Transient Assumptions (Units 1 and 2)

Parameter		Reference Transient	Uncertainty or Bias
c.	Initial stored energy/fuel rod behavior	Nominal (as coded)	ΔPCT_{MOD}
d.	Core heat transfer model	Nominal (as coded)	ΔPCT_{MOD}
e.	Delivery and bypassing of ECCS	Nominal (as coded)	Conservative
f.	Steam binding/entrainment	Nominal (as coded)	Conservative
g.	Noncondensible gases/accumulator nitrogen	Nominal (as coded)	Conservative
h.	Condensation	Nominal (as coded)	ΔPCT_{MOD}

Notes:

(1) ΔPCT_{MOD} indicates this uncertainty is part of code and global model uncertainty.
(2) ΔPCT_{PD} indicates this uncertainty is part of power distribution uncertainty.
(3) Calculated in conformance with the approved BE methodology (References 1 and 2).
(4) ΔPCT_{IC} indicates this uncertainty is part of initial condition uncertainty.
(5) Later calculations show that the split break is more limiting.

Table 4.1.1-2
Results of Farley Unit 2 Sensitivity Studies for RSG

Description	Blowdown PCT (°F)	Reflood1 PCT (°F)	Reflood2 PCT (°F)
Reference Split Transient (20% SGTP, C_D=1.0)	1591	1811	1796
0% SGTP	1446	1674	1418
C_D=0.8 Split	1383	1572	1465
C_D=1.2 Split	1592	1793	1639

Table 4.1.1-3 Best Estimate Large Break LOCA Results for RSG			
	First Reflood Peak	Second Reflood Peak	Criteria
50th Percentile PCT (°F)	<1688	<1524	N/A
95th Percentile PCT (°F)	<2056[1]	<1956[1]	<2200
Maximum Cladding Oxidation (%)	12		<17
Maximum Hydrogen Generation (%)	0.6		<1
Coolable Geometry	Core Remains Coolable		
Long-Term Cooling	Core Remains Cool in Long Term		

Notes:

(1) An evaluation performed for an increase in containment spray flow and a decrease in spray delay time resulted in a PCT penalty of 9°F for first reflood and 1°F for second reflood PCTs; thus, the final PCTs for the RSGs are:

First Reflood Peak: <2065°F
Second Reflood Peak: <1957°F

Table 4.1.1-4
Plant Operating Range Allowed by the LOCA Analysis (Units 1 and 2)

Parameter			Operating Range
1.0	**Plant Physical Description**		
	a)	Dimensions	No in-board assembly grid deformation during LOCA + SSE
	b)	Flow resistance	N/A
	c)	Pressurizer location	N/A
	d)	Hot assembly location	Anywhere in core
	e)	Hot assembly type	Fresh 17X17 V5, no restrictions Zirc-4 or ZIRLO™ cladding
	f)	Steam generator tube plugging level	≤ 20%
	g)	Fuel Assembly type	V5, Zirc-4 or ZIRLO™ cladding, 1.5X IFBA, LOPAR
2.0	**Plant Initial Operating Conditions**		
	2.1	Reactor Power	
		a) Core average linear heat rate (AFLUX)	Based on Core power ≤ 102% of 2775 MWt
		b) Peak linear heat rate (PLHR)	$F_Q \leq 2.5$
		c) Hot rod average linear heat rate (HRFLUX)	$F_{\Delta H} \leq 1.7$
		d) Hot assembly average heat rate (HAFLUX)[1]	≤ 1.7/1.04
		e) Hot assembly peak heat rate (HAPHR)	$F_{Q,HA} \leq 2.5/1.04$

Table 4.1.1-4 (Cont.)
Plant Operating Range Allowed by the LOCA Analysis (Units 1 and 2)

Parameter		Operating Range
	f) Axial power dist (PBOT, PMID)	Figure 4.1.1-20
	g) Low power region relative power (PLOW)	$0.2 \le PLOW \le 0.8$
	h) Hot rod burnup	≤ 75000 MWD/MTU, lead rod[2]
	i) Prior operating history	All normal operating histories
	j) MTC	≤ 0 at HFP
	k) HFP boron	Normal letdown (800 PPM)
	2.2 Fluid Conditions	
	a) T_{avg}	$567.2°F \pm 6°F \ge T_{avg} \le 577.2 \pm 6°F$
	b) Pressurizer pressure	P_{RCS} = 2250 psia ± 50 psi
	c) Loop flow	≥ 86,000 gpm (thermal design flow)
	d) T_{UH}	Current upper internals
	e) Pressurizer level	Normal level, automatic control
	f) Accumulator temperature range	$90°F \le T_{acc} \le 120°F$
	g) Accumulator pressure range	600 psia $\le P_{acc} \le$ 680 psia
	h) Accumulator volume (tank only)	$965 \le V_{acc} \le 995$ ft^3
	i) Accumulator f(L/D)	Current line configuration
	j) Minimum accumulator boron	≥ 2100 ppm

Table 4.1.1-4 (Cont.)
Plant Operating Range Allowed by the LOCA Analysis (Units 1 and 2)

Parameter		Operating Range
3.0	**Accident Boundary Conditions**	
	a) Break location	N/A
	b) Break type	N/A
	c) Break size	N/A
	d) Offsite power	On or off
	e) Safety injection flow	≥ values used in reference case (Figure 4.1.1-15)
	f) Safety injection temperature	70°F[3] ≤ SI Temp ≤ 100°F
	g) Safety injection delay	≤ 12 seconds (with offsite power) ≤ 27 seconds (without offsite power)
	h) Containment pressure	Bounded - Based on minimum containment pressure of 14.7 psia. Bounding pressure curve (Figure 4.1.1-19) is based on COCO containment calculation using conditions supplied in Table 4.1.1-5.
	i) Single failure	Loss of one train
	j) Control rod drop time	N/A

Notes:

(1) Note that this limit is a maximum value. For purposes of core design calculations or in core measurements, the maximum value must be reduced by an additional 4%, yielding a value of ≤ 1.7/1.08 = 1.574.

(2) Based on BE LOCA Generic Studies. Limit applies to BE LBLOCA only.

(3) 70°F is a statistical lower limit for the SI temperature based on actual plant data. Temperatures as low as the technical specification lower limit of 35°F are acceptable.

Table 4.1.1-5
Large Break LOCA Containment Data Used for Calculating Containment Pressure

Parameter	Input Value
Net Free Volume	2,150,000 ft^3
Initial Conditions	
Pressure	14.7 psia
Temperature	90.0°F
RWST temperature	35.0°F
Service water temperature	40.0°F
Temperature outside containment	20.0°F
Initial spray temperature	35.0°F
Spray System	
Runout flow for a spray pump	2775 gal/min[1]
Number of spray pumps operating	2
Post-accident spray system initiation delay with LOOP	48 s[1]
without LOOP	32.0 s[1]
Maximum spray system flow	5500 gal/min[1]
Containment Fan Coolers	
Post accident initiation fan coolers	27.4 s
Number of fan coolers operating	4

Table 4.1.1-5 (Cont.)
Large Break LOCA Containment Data Used for Calculating Containment Pressure

Structural Heat Sinks					
Wall	**T_{AIR} (°F)**	**Area (ft^2)**	**Height (ft)**	**T_{Init} (°F)**	**Thickness (in.)**
1. Containment wall and dome	40 (Unit 1) 20 (Unit 2)	75000	10	90	0.25 Carbon Steel/ 45 Concrete
2. Containment penetrations, plates and liner stiffeners	40 (Unit 1) 20 (Unit 2)	4700	10	90	0.6 Carbon Steel/ 45 Concrete
3. Unlined concrete	90	69800	10	90	9 Concrete
4. Galvanized carbon steel	90	77000	10	90	0.004 Zinc/.07 Steel
5. Thin painted carbon steel (<0.5 in.)	90	80500	10	90	0.135 Steel
6. Painted steel (<0.5 in.)	90	47600	10	90	0.36 Steel
7. Painted steel (<2.0 in.)	90	23600	10	90	0.7 Steel
8. Thick painted steel	90	11800	10	90	2.3 Steel
9. Floor	50	13275	10	90	108 Concrete
10. Refueling pool liner	90	7900	10	90	0.25 Stainless Steel/ 18 Concrete
11. Unpainted stainless steel	90	12500	10	90	0.105 Stainless Steel
12. Carbon steel containment storage boxes(2)	90	1350	10	90	0.062 Carbon steel

Notes:

(1) An evaluation was performed to support an increase in containment spray flow to 3400 gpm/pump for a total flow of 6800 gpm maximum spray system flow and a reduction of delay time to 26 seconds. This evaluation resulted in a PCT penalty of 9°F for the first reflood peaks and 1°F for the second reflood peaks. The containment pressure shown in Figure 4.1.1-19 does not reflect this increase in containment spray.

(2) A safety evaluation was completed to support the presence of permanent storage boxes in containment. The effect of these storage boxes is not included in the containment pressure shown in Figure 4.1.1-19.

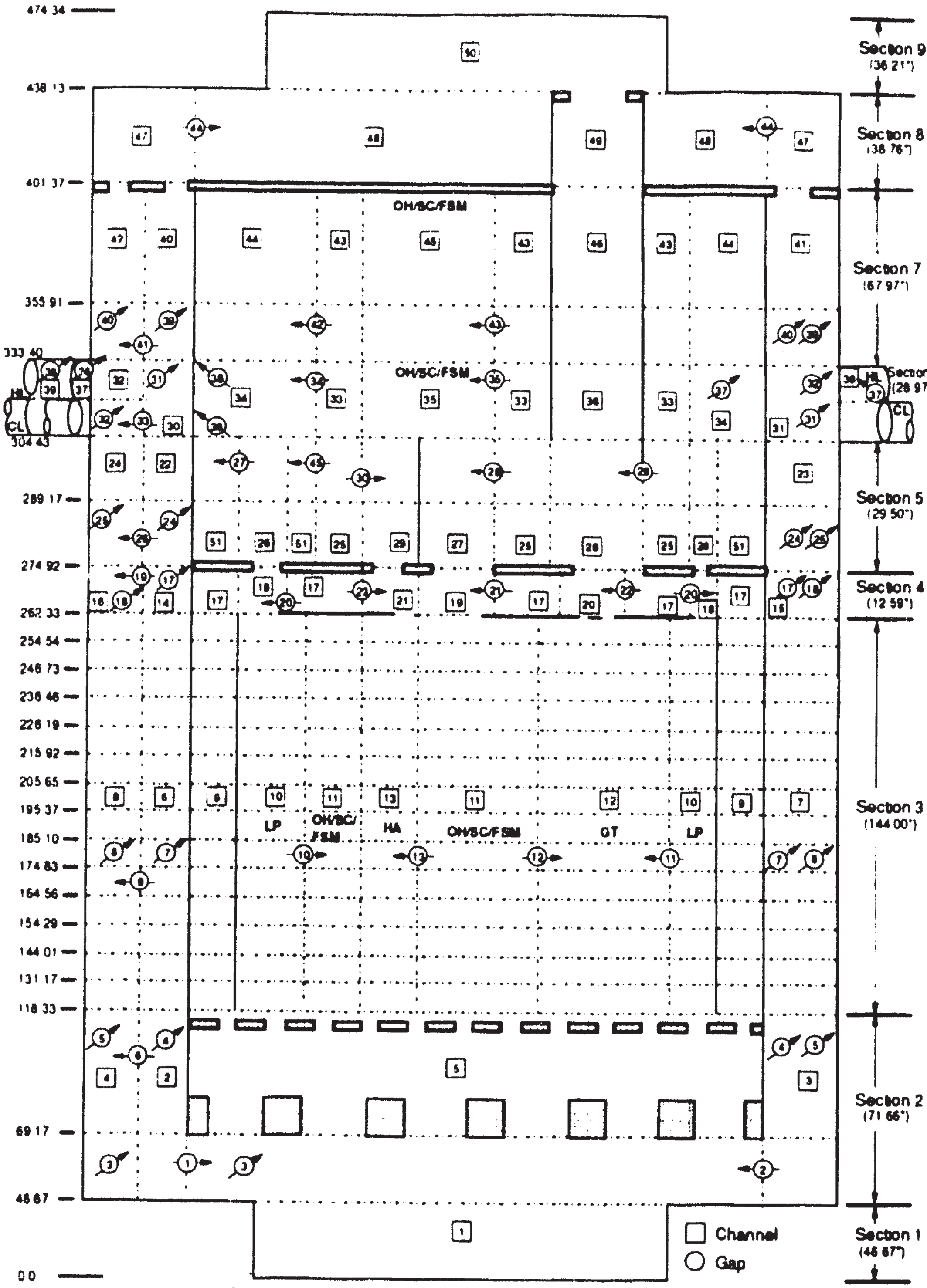


Figure 4.1.1-1
Unit 1 Vessel Noding (Vertical View)

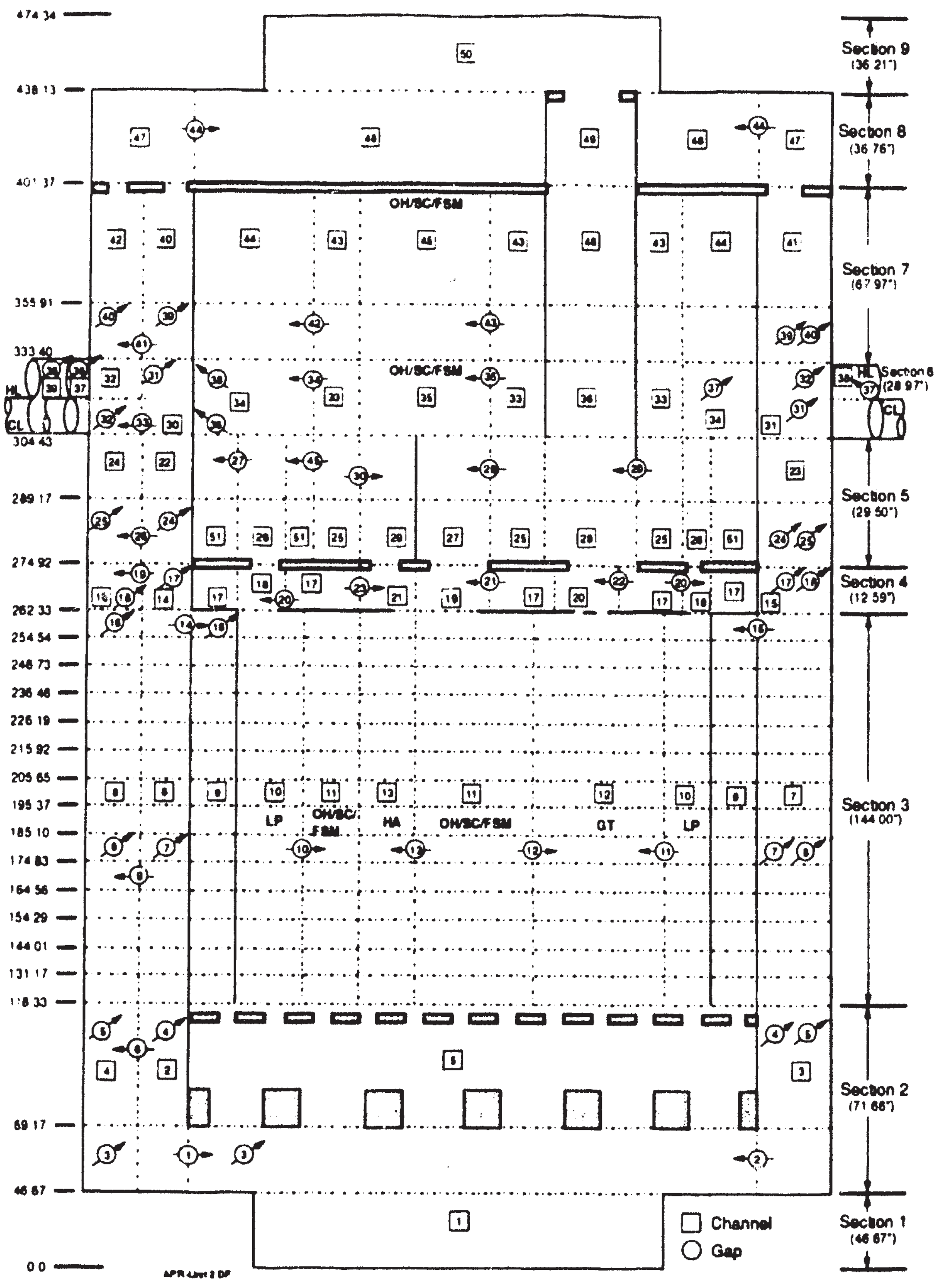


Figure 4.1.1-2
Unit 2 Vessel Noding (Vertical View)

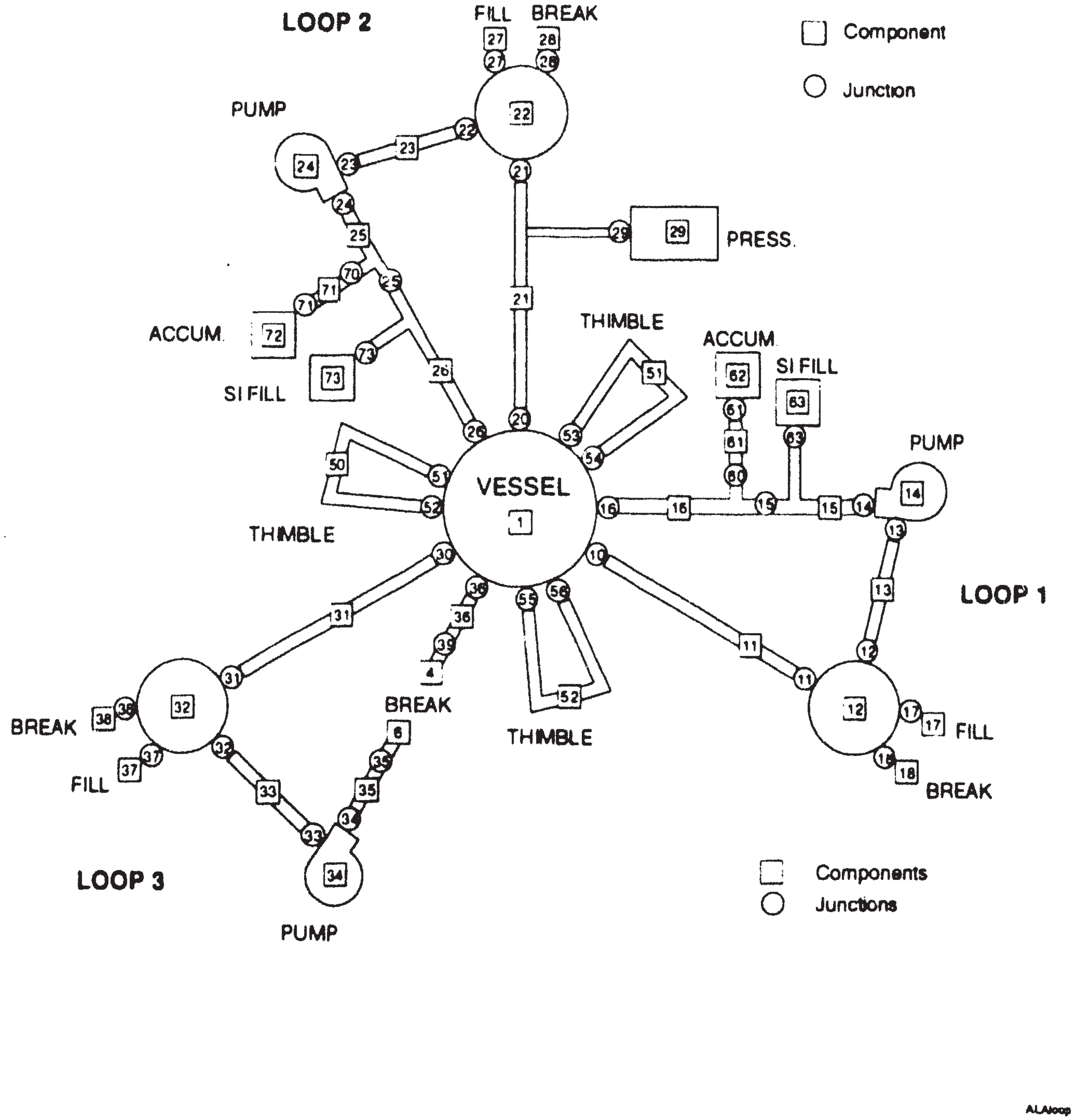


Figure 4.1.1-3
Units 1 and 2 WCOBRA/TRAC Model Vessel/Loop Layout (Transient)

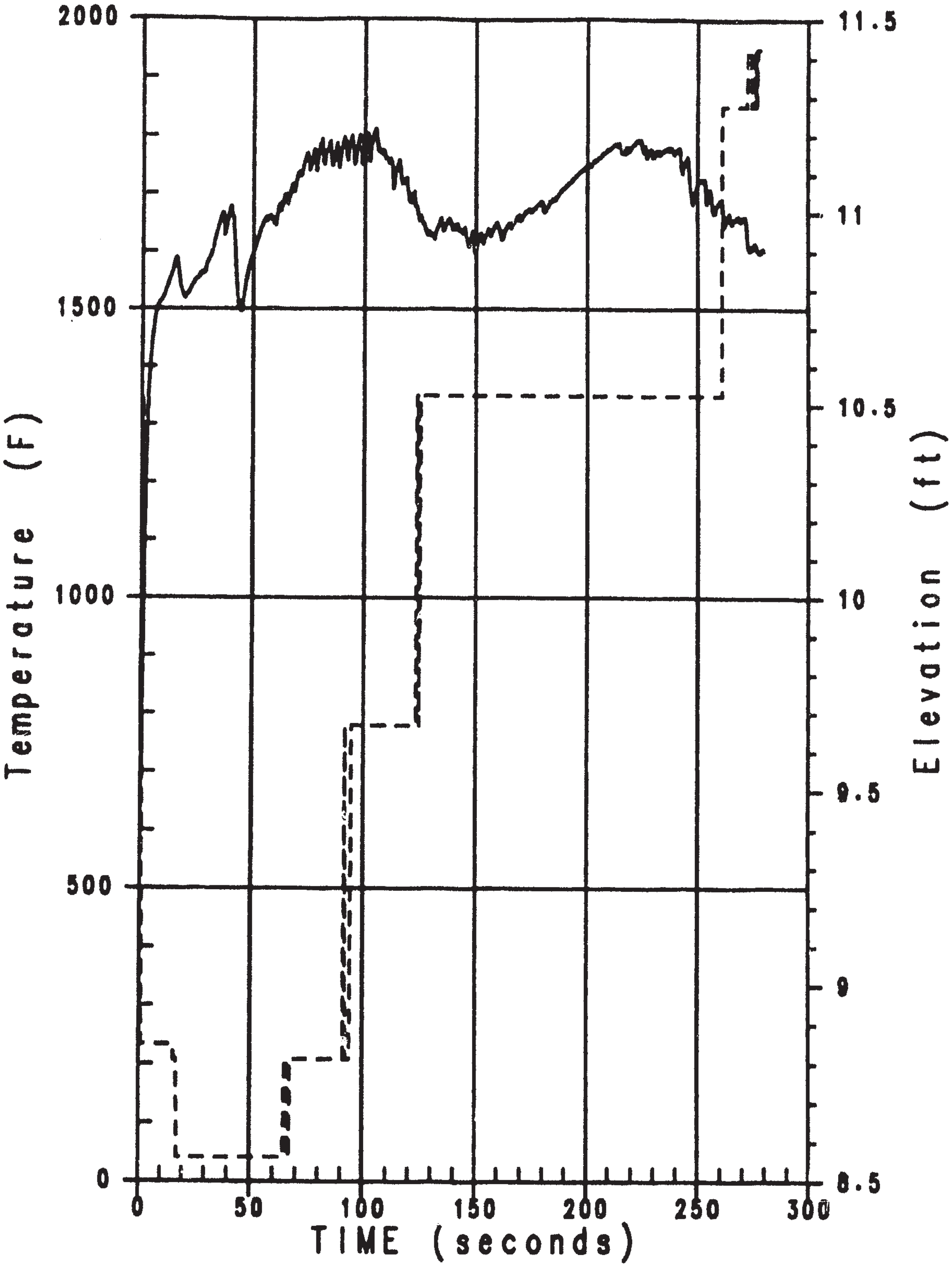


Figure 4.1.1-4
Peak Cladding Temperature (Reference Split Transient)

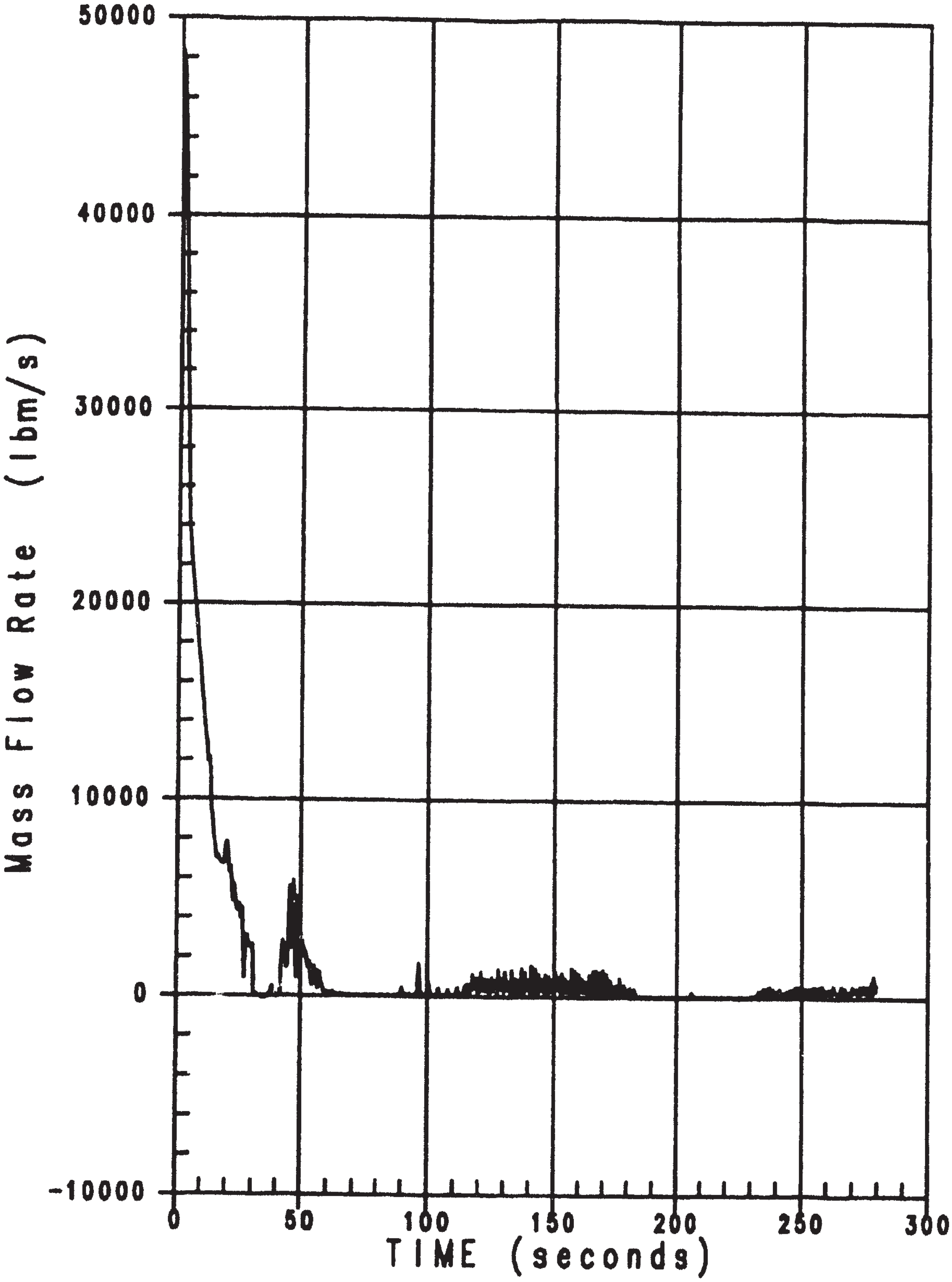


Figure 4.1.1-5
Break Flow (Split Break)

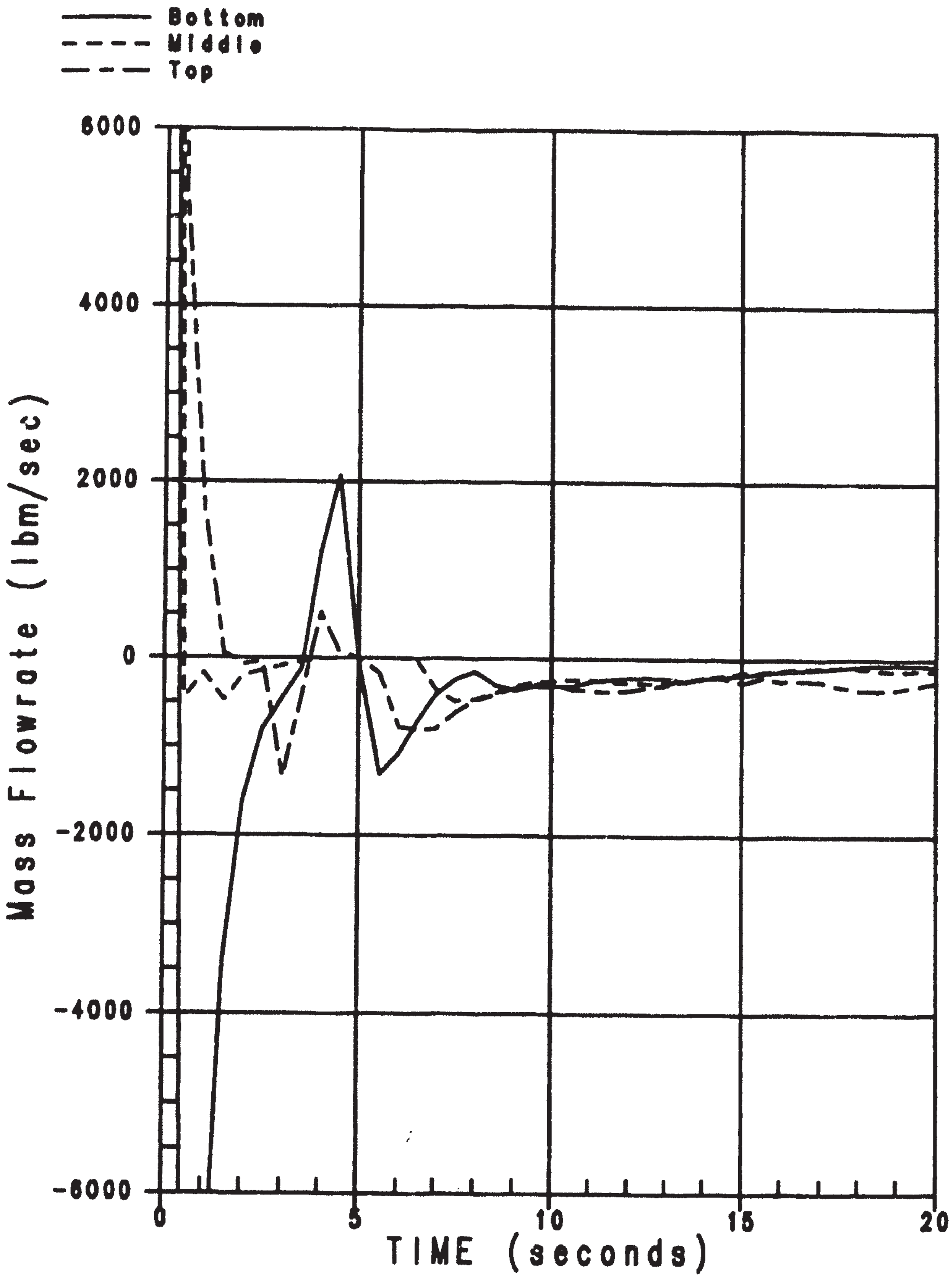


Figure 4.1.1-6
Flowrate at Top, Middle, and Bottom of Core During Blowdown

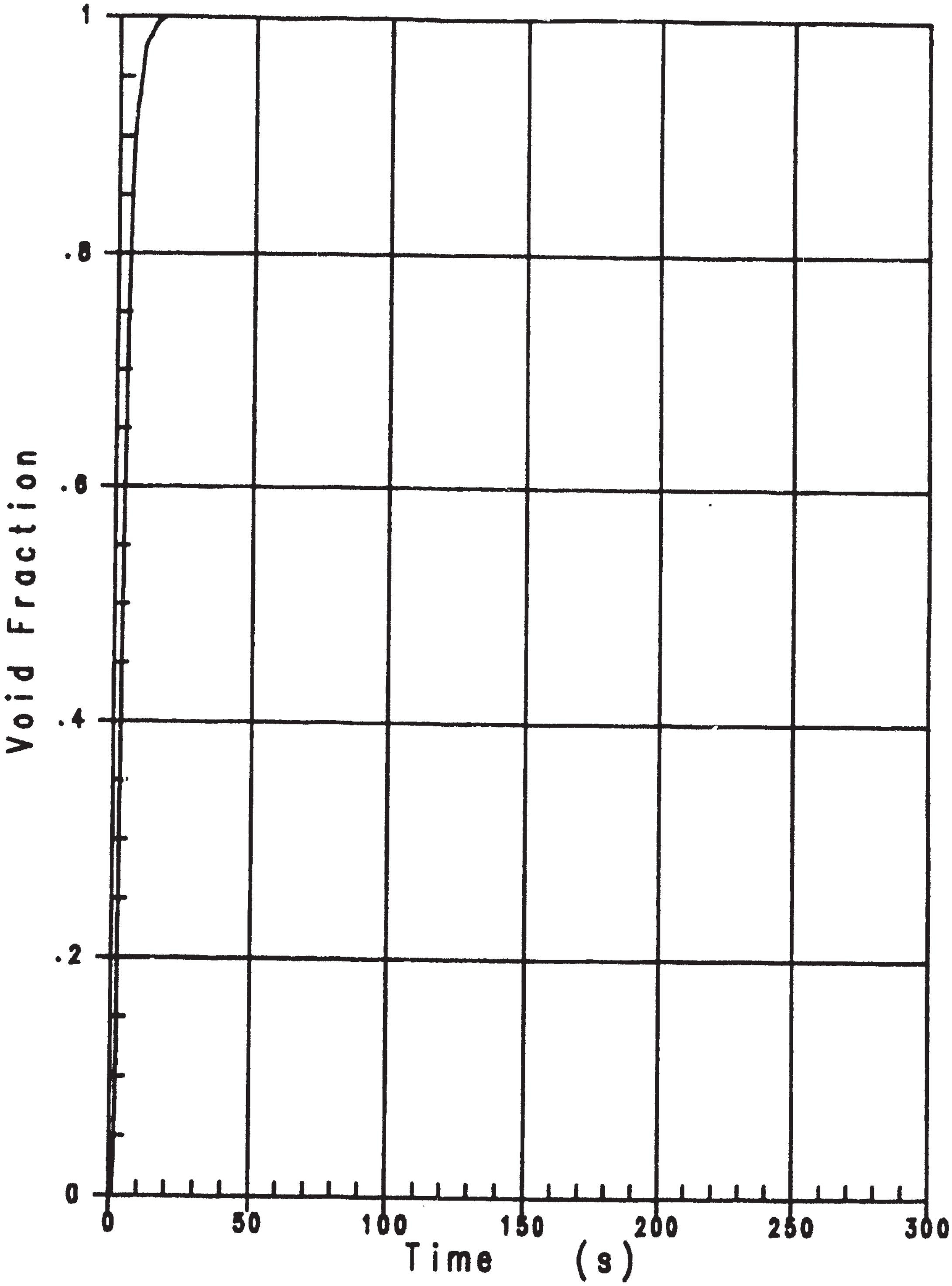


Figure 4.1.1-7
Intact Loop Pump Inlet Void Fraction

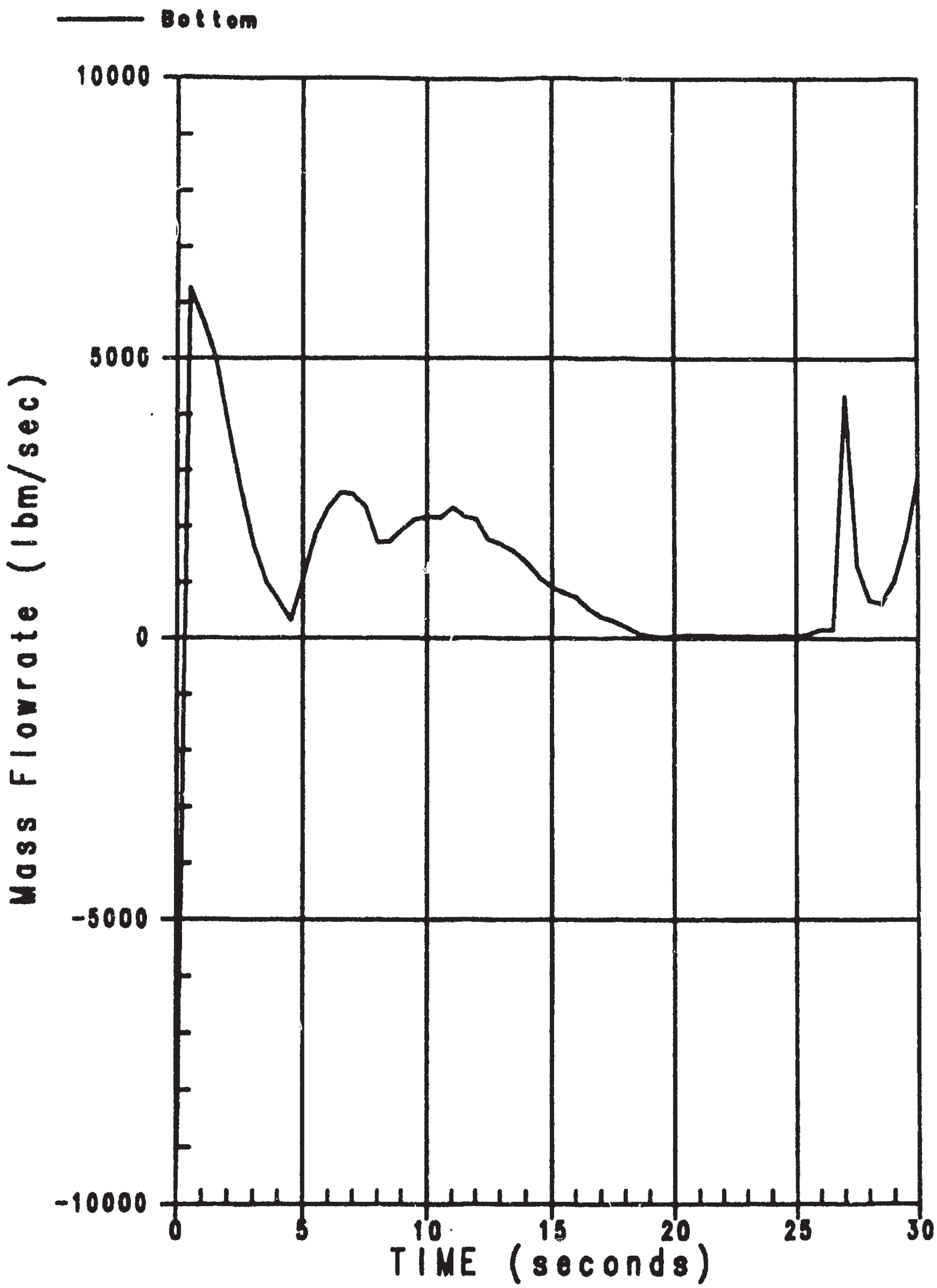


Figure 4.1.1-8
Flowrate at Bottom of Broken DC Channel

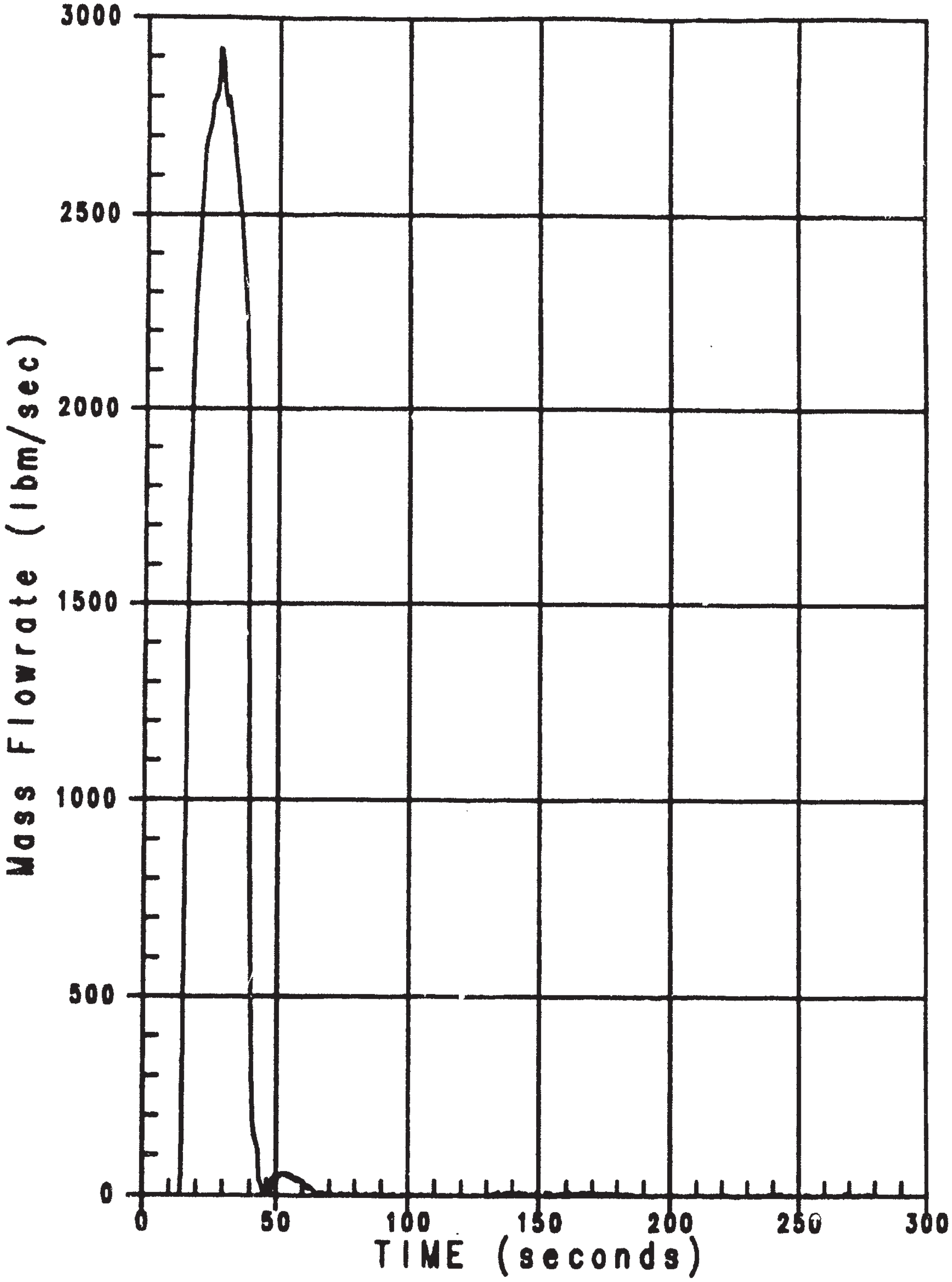


Figure 4.1.1-9
Accumulator Liquid Flow

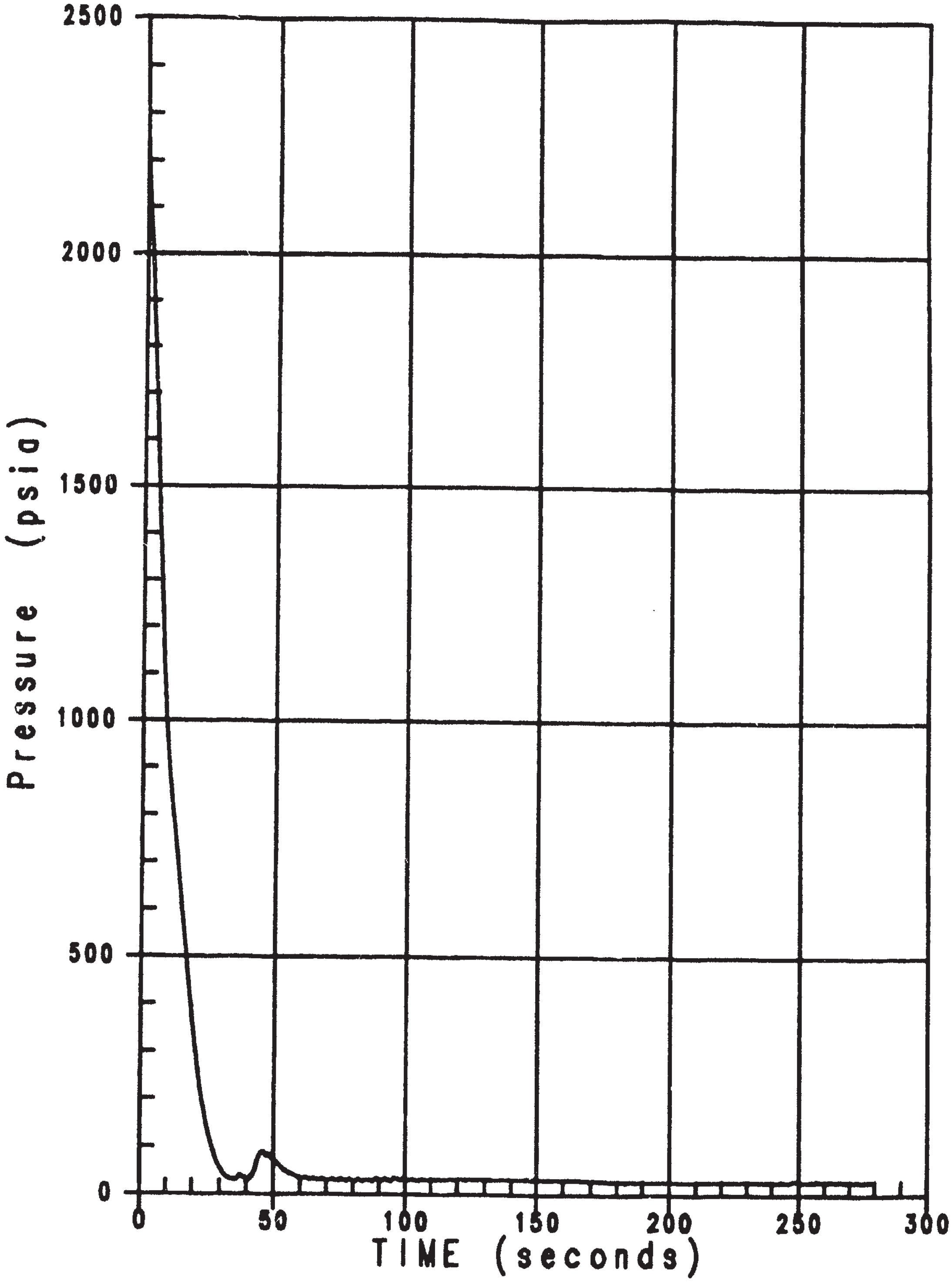


Figure 4.1.1-10
Pressurizer Pressure

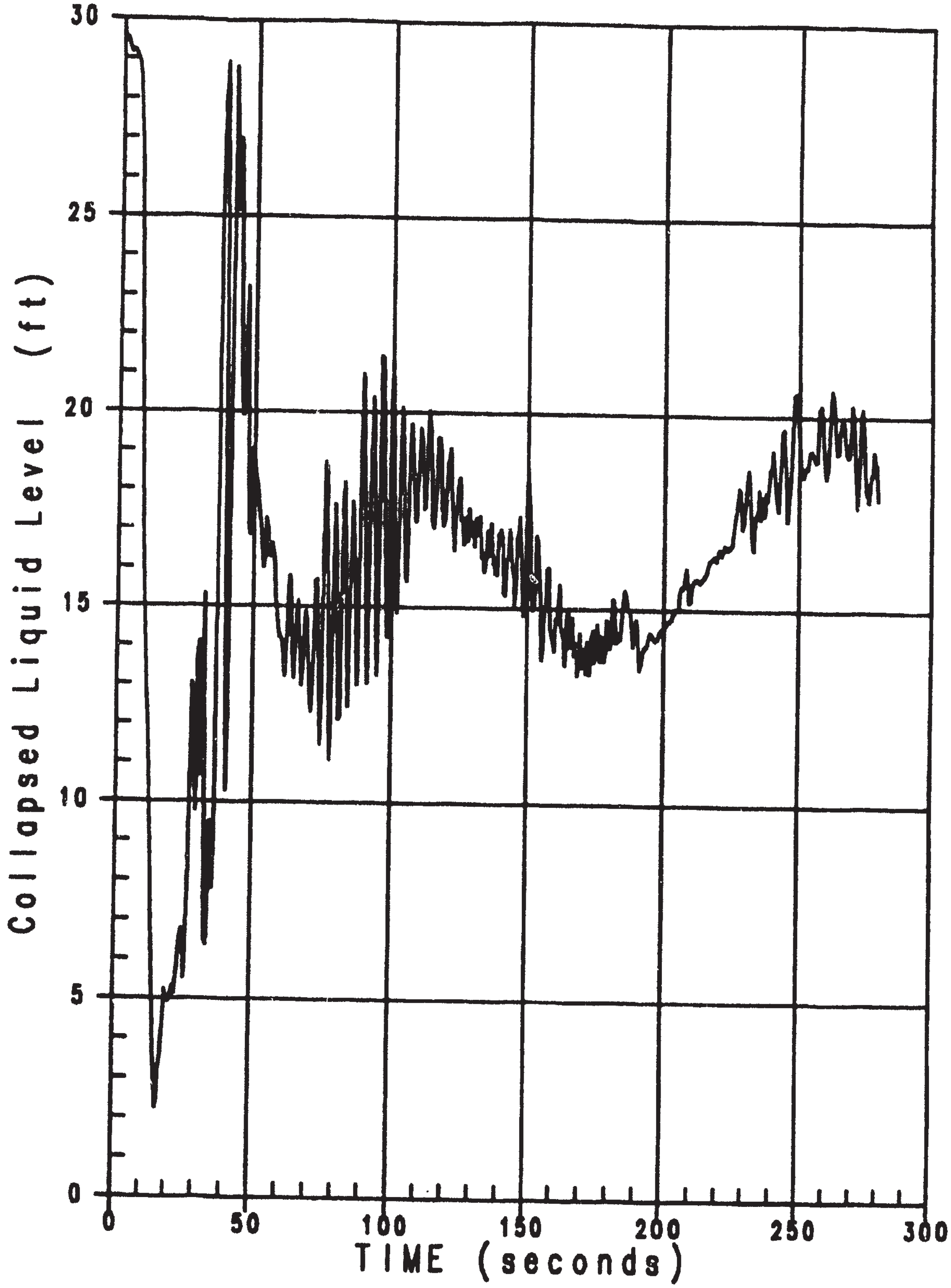


Figure 4.1.1-11
Downcomer Channels Collapsed Liquid Level

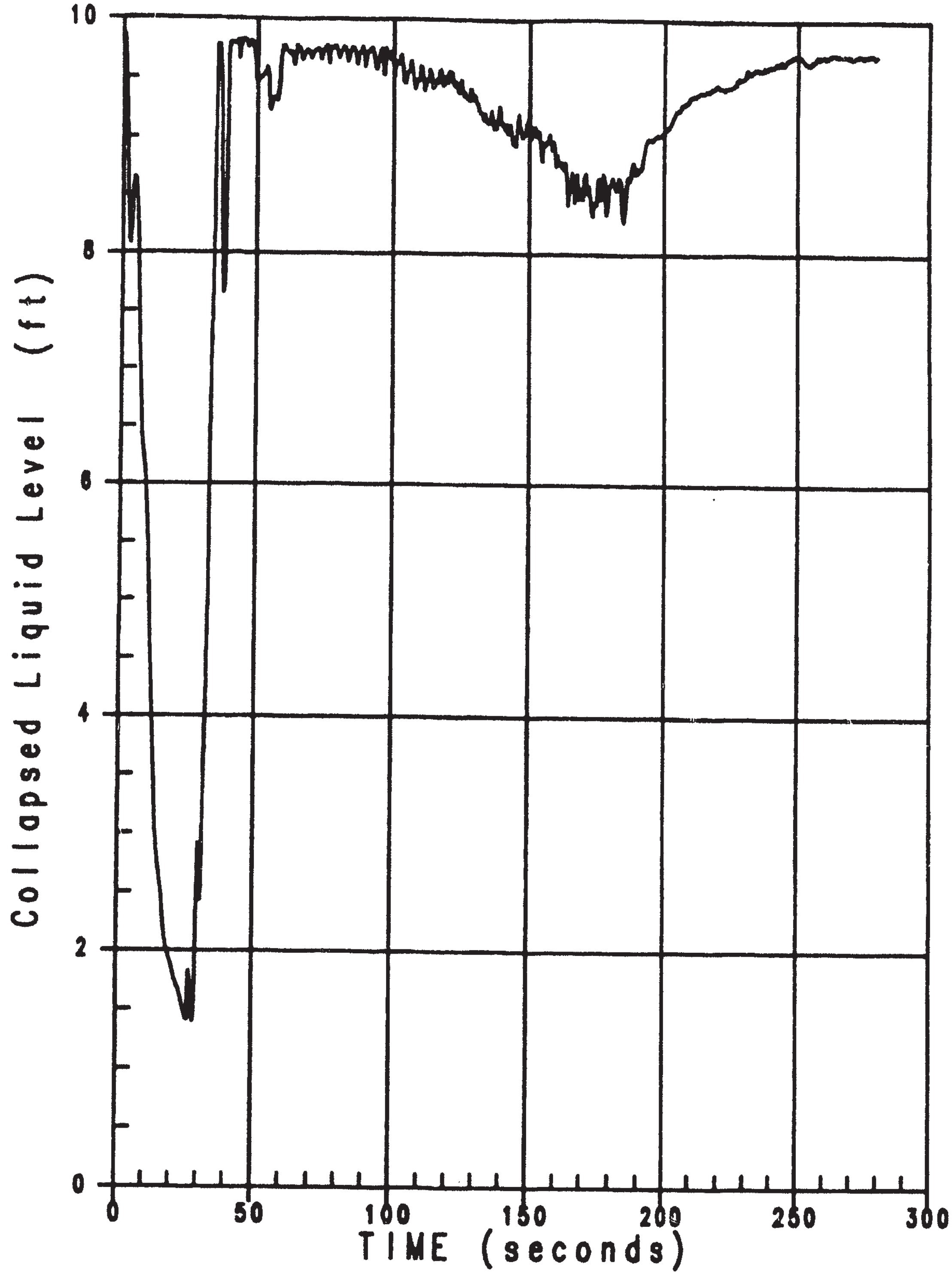


Figure 4.1.1-12
Lower Plenum Collapsed Liquid Level

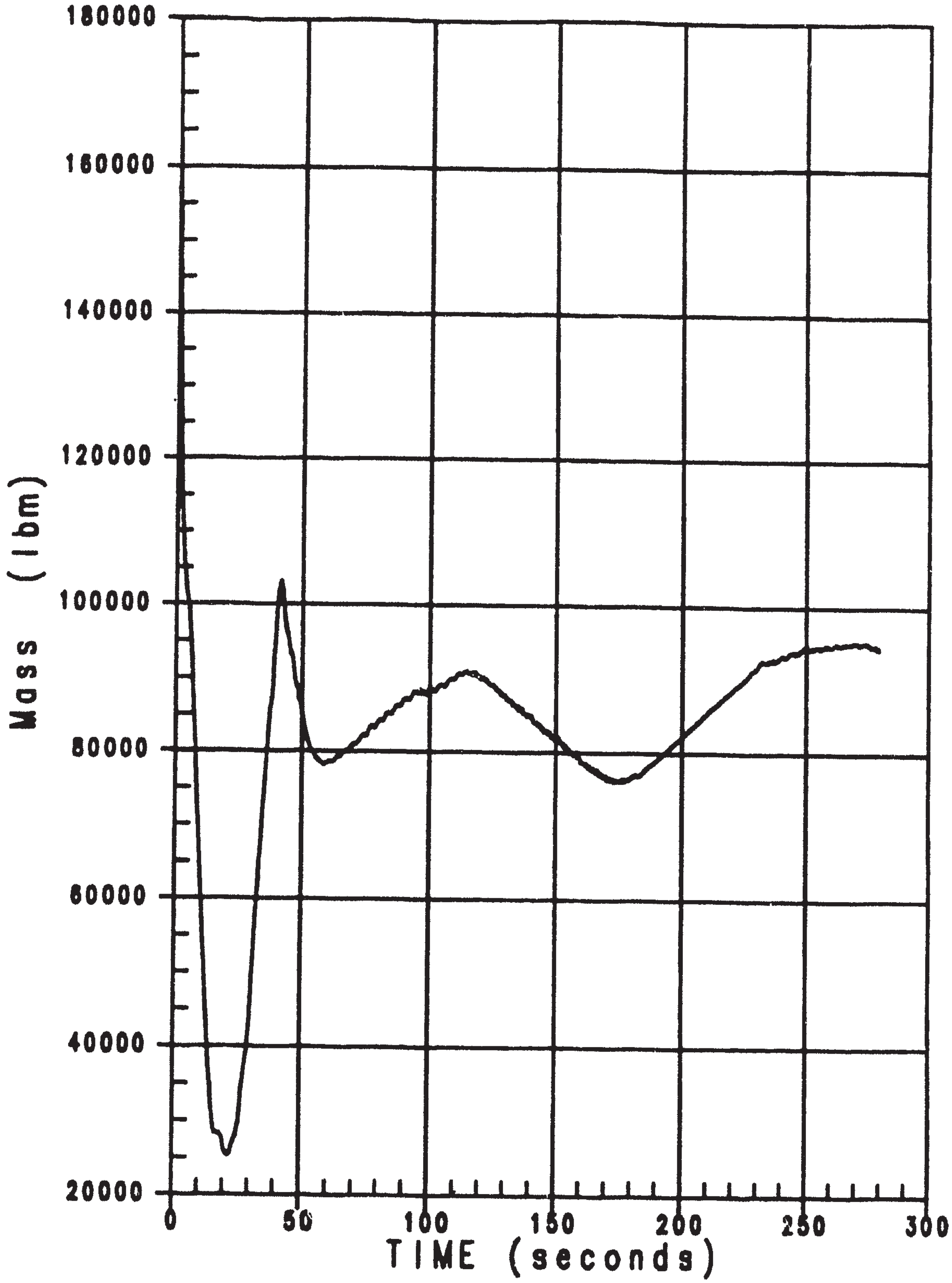


Figure 4.1.1-13
Vessel Fluid Mass

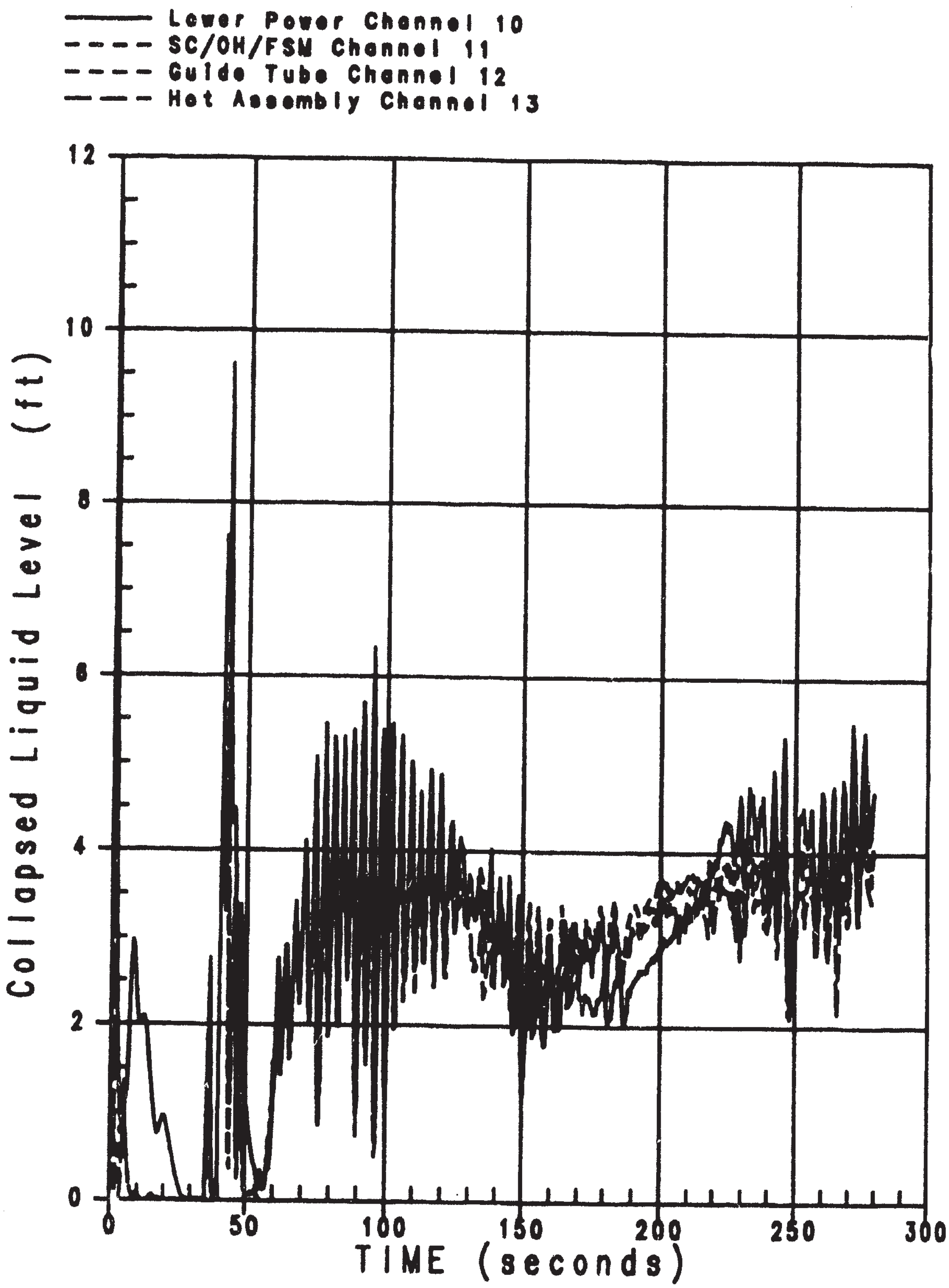


Figure 4.1.1-14
Core Channels Collapsed Liquid Level

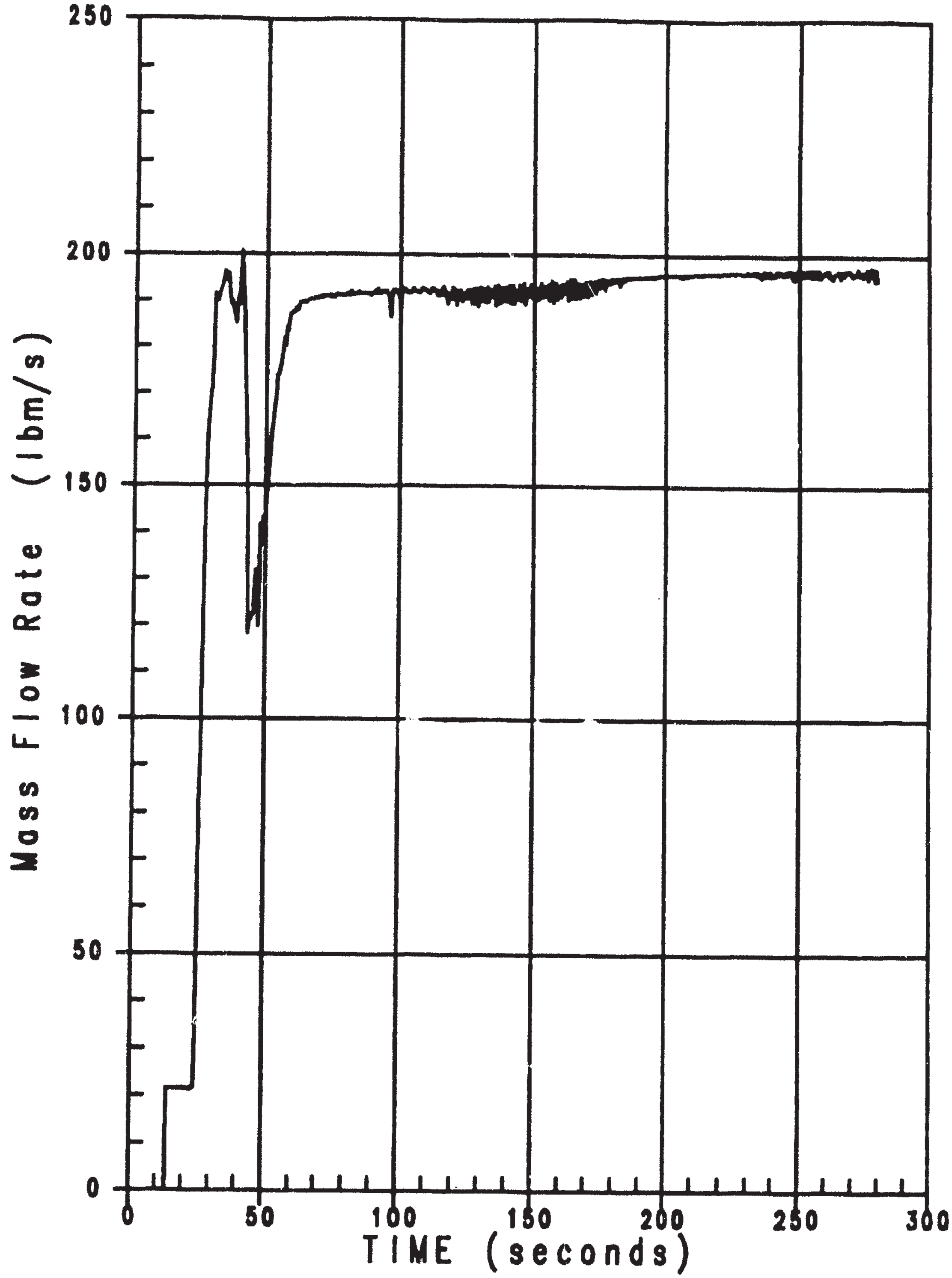


Figure 4.1.1-15
Safety Injection Flow

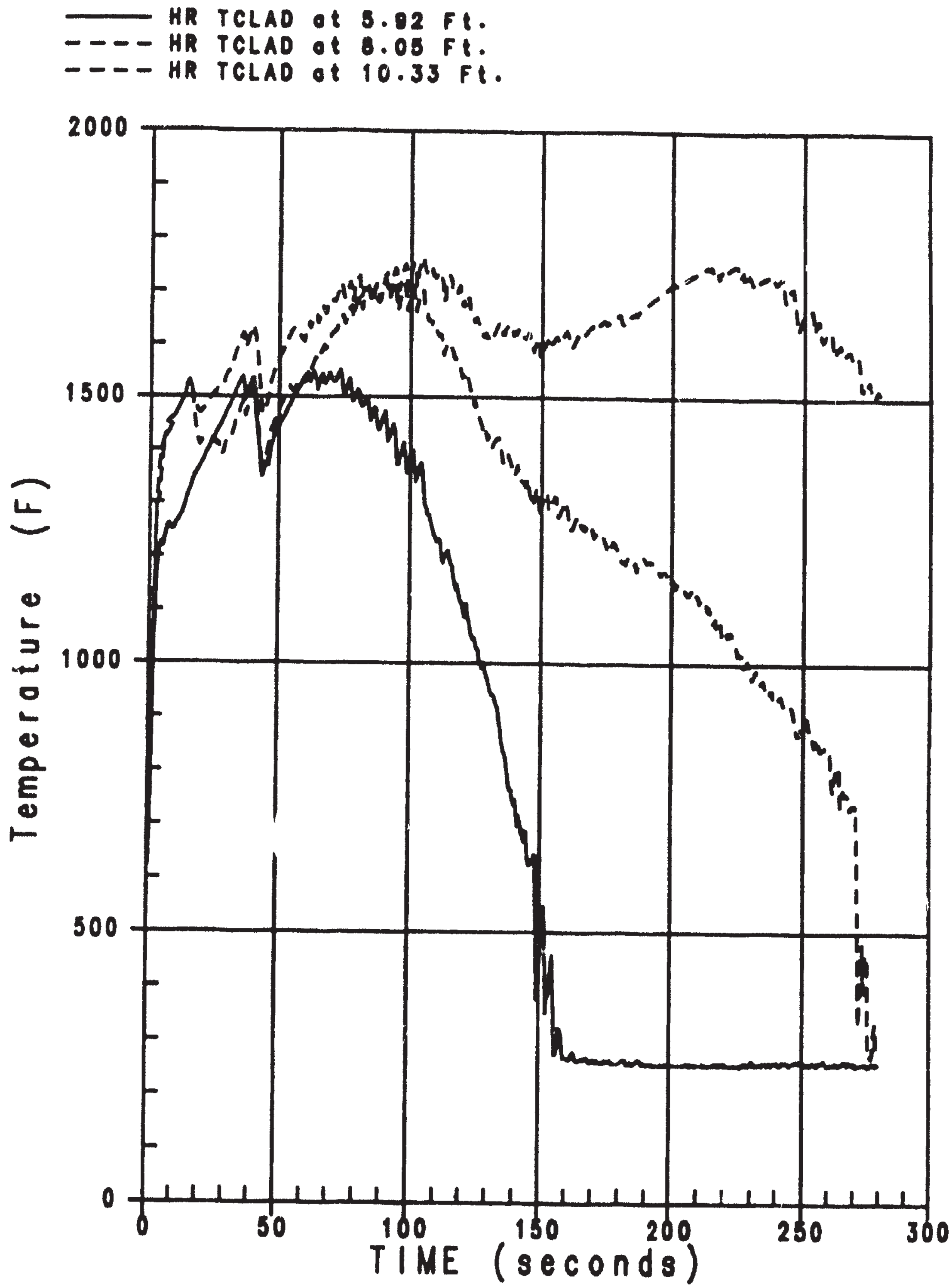


Figure 4.1.1-16
Cladding Temperature at Various Elevations (Hot Rod)

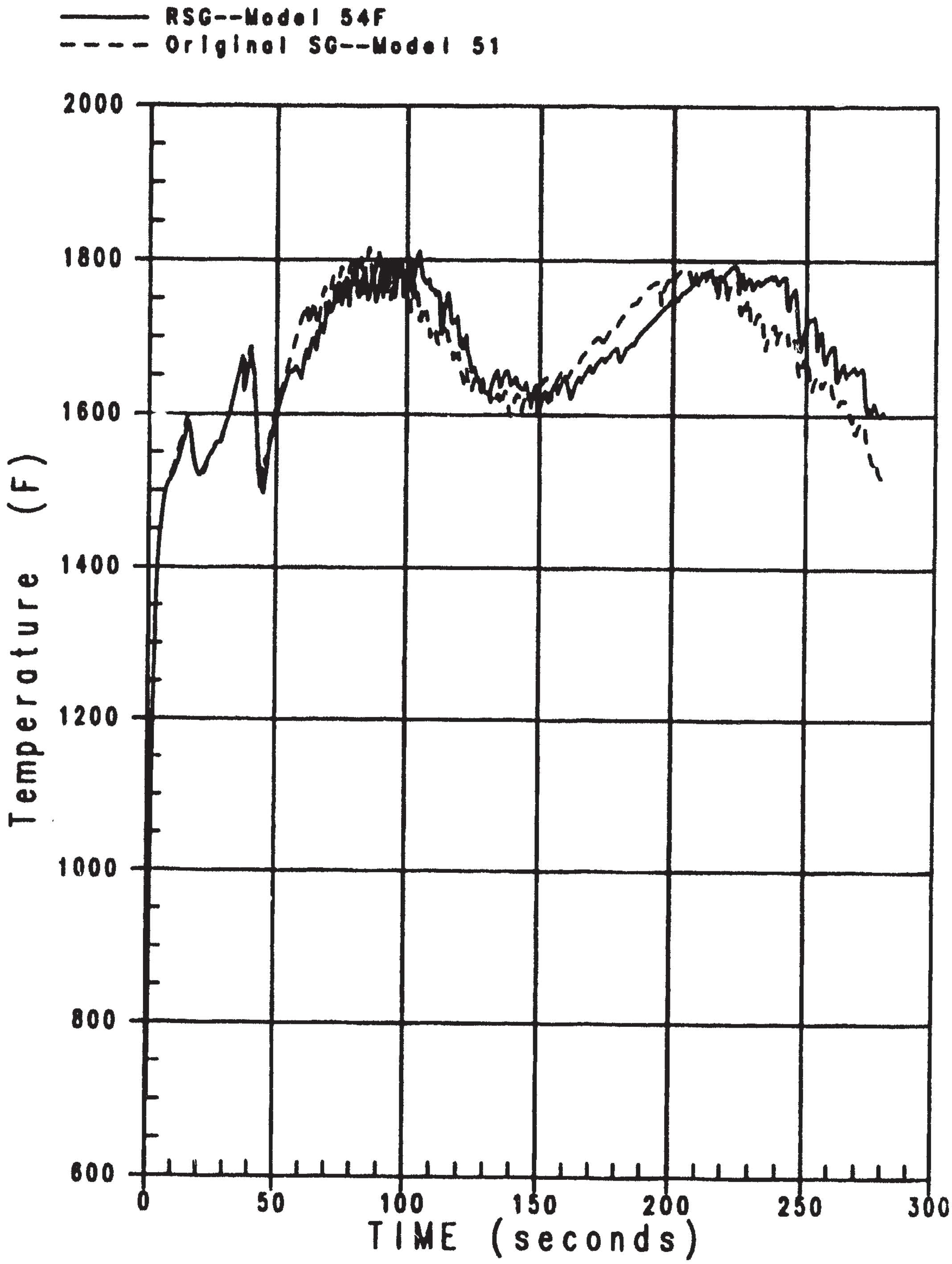


Figure 4.1.1-17
Farley Reference Split Break - CD = 1.0 Peak Cladding Temperature Hot Rod

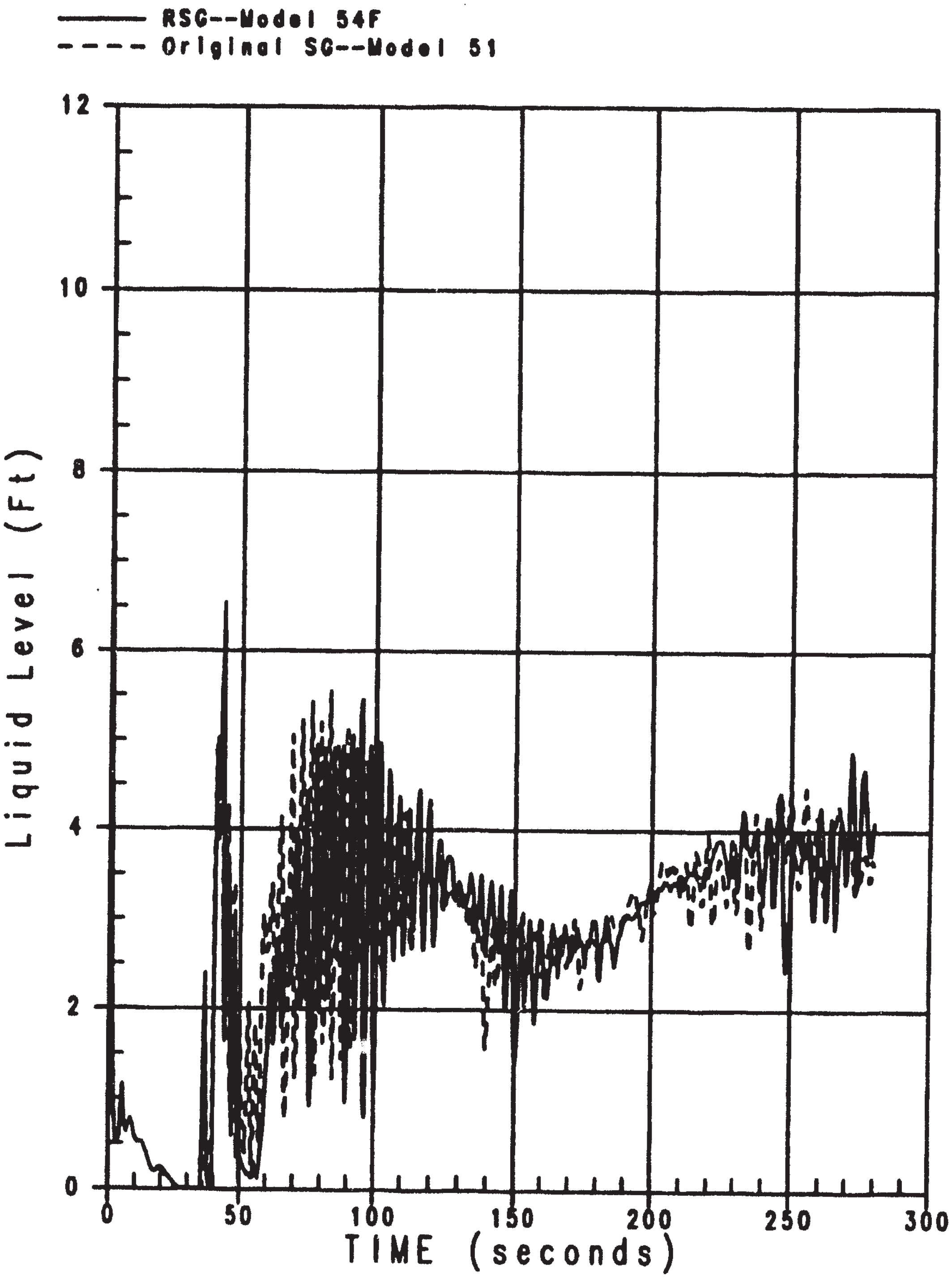


Figure 4.1.1-18
Farley Reference Split Break - CD = 1.0 Average Core Liquid Level - Ch 10, 11, 12, 13

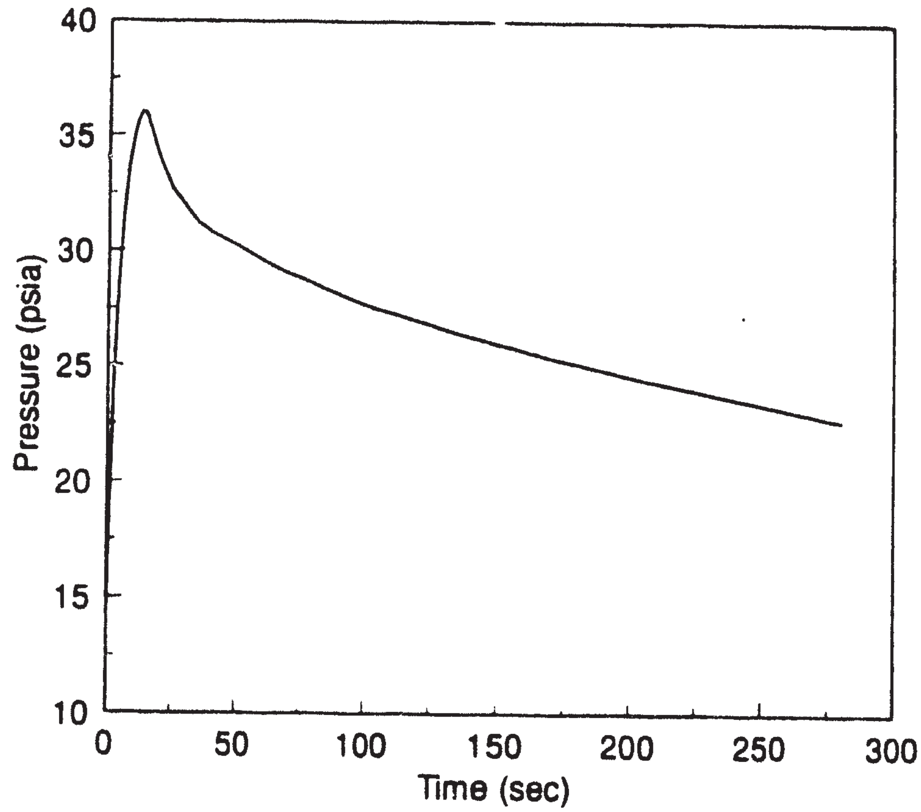


Figure 4.1.1-19
Lower Bound Containment Pressure Used for Farley Best Estimate Large Break LOCA

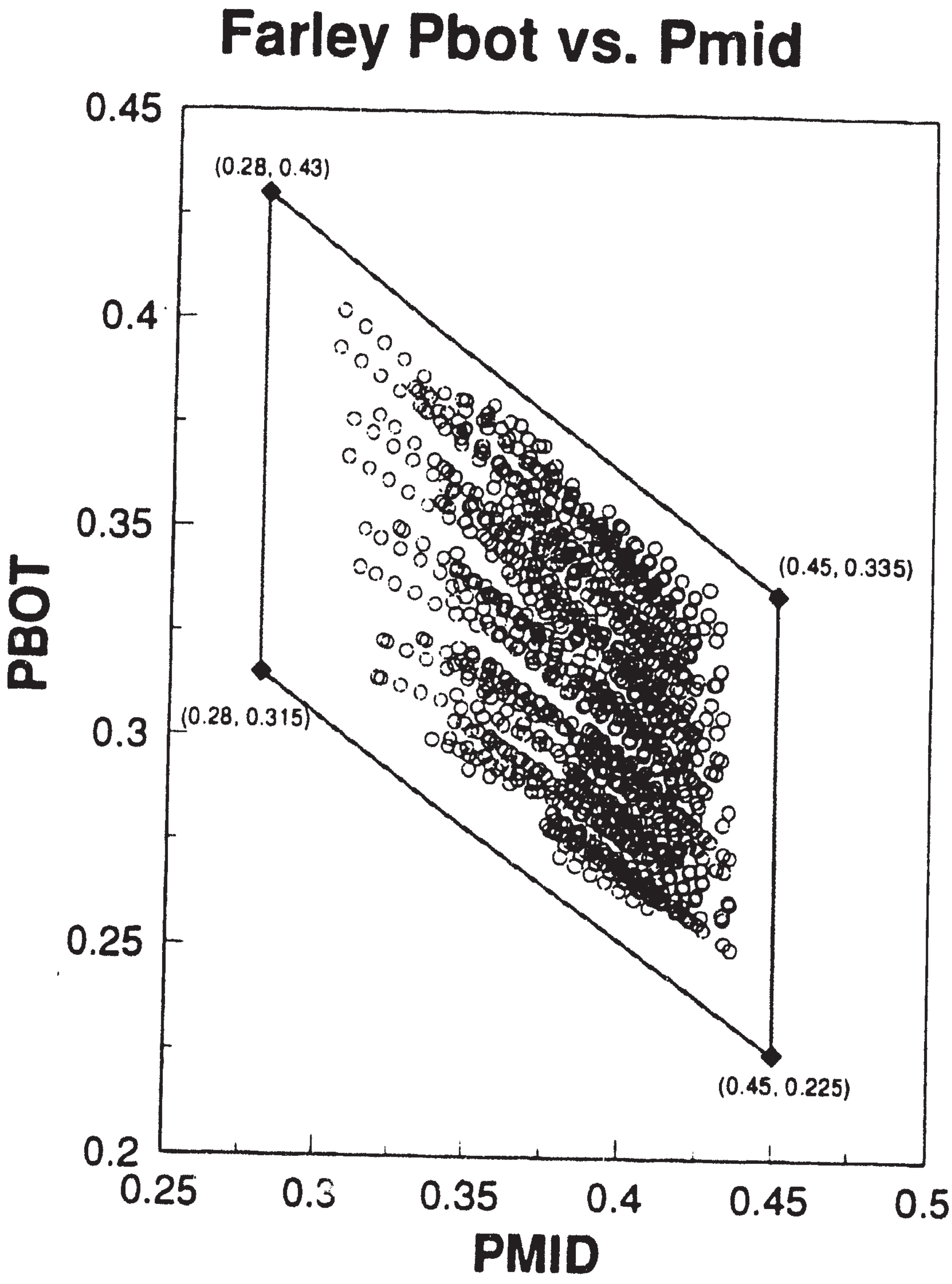


Figure 4.1.1-20
Farley Units 1/2 PBOT/PMID Limits Superimposed on a Plot of All Possible Power Shapes for a Typical Fuel Cycle

4.1.2 Small Break LOCA

4.1.2.1 Introduction

This section contains information regarding the SBLOCA analysis and evaluations performed in support of Farley Units 1 and 2 with Model 54F RSGs. The purpose of analyzing the SBLOCA is to demonstrate conformance with the 10 CFR 50.46 (Reference 4) requirements for the conditions associated with the RSGs. Important input assumptions, as well as analytical models and analysis methodology for the SBLOCA, are contained in subsequent sections. Analysis results are provided in the detailed descriptions of the limiting transient and in tables. Analyses show that no design or regulatory limit related to the SBLOCA would be exceeded due to the plant parameters with Model 54F RSGs.

4.1.2.2 Input Parameters and Assumptions

The important plant conditions and features are listed in Table 4.1.2-1. Several additional considerations that are not identified in Table 4.1.2-1 are discussed below.

The hot rod axial power shape modeled in the detailed description of the limiting transient analysis is chosen because it represents a distribution with power concentrated in the upper regions of the core (the axial offset is +13 percent). Such a distribution is limiting for SBLOCA since it minimizes coolant swell while maximizing vapor superheating and fuel rod heat generation at the uncovered elevations. The chosen power shape has been conservatively scaled to a flat K(z) envelope based on the peaking factors shown in Table 4.1.2-1.

The 2-inch, 3-inch, and 4-inch SBLOCA analysis cases assume degraded safety injection flow from only one high head safety injection (HHSI) pump. The flow from the low head safety injection (LHSI) pump is not modeled in these analysis cases since the RCS pressure experienced in these transients does not reach the LHSI pressure range.

The 6-inch small break LOCA analysis case assumes degraded safety injection flow from one HHSI pump and one LHSI pump since the RCS pressure experienced in this transient is low enough to reach the LHSI pressure range.

4.1.2.3 Description of Analyses/Evaluations Performed

ANALYTICAL MODEL

For small breaks, the NOTRUMP computer code (References 2 and 3) is employed to calculate the transient depressurization of the RCS, as well as to describe the mass and energy release of the fluid flow through the break. The NOTRUMP computer code is a one-dimensional general network code incorporating a number of advanced features. Among these advanced features are: calculation of thermal non-equilibrium in all fluid volumes; flow regime-dependent drift flux calculations with counter-current flooding limitations; mixture level tracking logic in multiple-stacked fluid nodes; regime-dependent drift flux calculations in multiple-stacked fluid nodes; and regime-dependent heat transfer correlations. The NOTRUMP SBLOCA ECCS

Evaluation Model was developed to determine the RCS response to design basis SBLOCAs, and to address NRC concerns expressed in NUREG-0611 (Reference 3).

The RCS model is nodalized into volumes interconnected by flowpaths. The broken loop is modeled explicitly, while the intact loops are lumped together into a second loop. Transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum. The multi-node capability of the program enables explicit, detailed spatial representation of various system components which, among other capabilities, enables a proper calculation of the behavior of the loop seal during a SBLOCA. The reactor core is represented as heated control volumes with associated phase separation models to permit transient mixture height calculations.

Fuel cladding thermal analyses are performed with a version of the LOCTA-IV code (Reference 5) using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam flow, and mixture heights as boundary conditions.

ANALYSIS

Since the prior uprate analysis with the original Model 51 steam generators indicated that the 3-inch break was the most limiting condition and the limiting break size is not expected to shift due to the RSGs, four cases for the 3-inch break are run consisting of up-flow/down-flow (Unit 1/Unit 2) and high/low T_{avg} conditions. Using the limiting 3-inch configuration, the 2-inch, 4-inch, and 6-inch equivalent diameter cold leg breaks are performed using the analytical model described above to confirm that the limiting break size, in fact does not shift. (The 6-inch break case conservatively models a break in the safety injection line (inner diameter = 5.189 in)).

The most limiting single active failure assumed for a SBLOCA is that of an emergency power train failure that results in the loss of one complete train of ECCS components. In addition, a loss of offsite power (LOOP) is assumed to occur coincident with reactor trip, and therefore, at most, one high head safety injection (SI) pump and one low head, or residual heat removal (RHR), pump will be used. In the 2-inch, 3-inch, and 4-inch analysis cases, only one HHSI pump is modeled, and the LHSI pump is not needed since the RCS pressure experienced in the transients did not reach the LHSI pressure rang .ı the 6-inch analysis case, one HHSI pump and one LHSI pump are needed since the RCS pressure experienced in the transient did reach the LHSI pressure range. The assumption of LOOP as the limiting single failure for SBLOCA does not change as a result of the steam generator replacement. LOOP is limiting due to the fact that one train of SI, one motor-driven auxiliary feedwater (AFW) pump, and power to the RCPs are all lost. The turbine-driven AFW pump starts on the RCP undervoltage signal due to the LOOP. Any other single failure would not result in a more limiting scenario since either increased SI flow or AFW flow or continued RCP flow would improve the overall transient results.

The 2-inch, 3-inch, and 4-inch SBLOCA analysis cases performed for Farley Units 1 and 2 with RSGs assumes ECCS flow is delivered to both the intact and broken loops at the RCS backpressure. RCS backpressure has been assumed for the SI delivery since these break sizes are smaller than the SI line (inner diameter = 5.189 in.), making it impossible for the break to be the SI line sheared off. For these cases, the break is in the bottom of the RCS cold leg piping (the limiting break location). The 6-inch SBLOCA analysis case assumes ECCS flow is delivéred only to the intact loops with one line spilling to containment backpressure. No ECCS flow is modeled to the broken loop since the break is assumed to occur on the SI line. (The SI break is not specifically modeled in this analysis case, only assumed with regard to SI. For this case, the break location is in the bottom of the cold leg to conservatively represent a break in the SI line.) Additionally, for all analysis cases, the new SI condensation model is used since the final model implementation was approved by the NRC prior to completion of this analysis (See Reference 6). Finally, the effects of containment spray on refueling water storage tank (RWST) draindown and cold leg recirculation switchover are considered in the modeling of SI flow. At the time of switchover to cold leg recirculation, the SI enthalpy is appropriately increased by the NOTRUMP computer code. Also, the LHSI pumps are assumed to be turned off for 180 seconds after initiation of switchover (per Farley switchover procedures). However, no HHSI flow reduction is assumed while switching over to cold leg recirculation since Farley Units 1 and 2 are not subject to this circumstance.

Prior to break initiation, the plant is assumed to be in a full power (102 percent) equilibrium condition, i.e., the heat generated in the core is being removed via the secondary side. Other initial plant conditions assumed in the analysis are given in Table 4.1.2-1. Subsequent to the break opening, a period of RCS blowdown ensues in which the heat from fission product decay, the hot reactor internals, and the reactor vessel continues to be transferred to the RCS fluid. The heat transfer between the RCS and the secondary system may be in either direction and is a function of the relative temperatures of the primary and secondary side. In the case of continuous heat addition to the secondary side during a period of quasi-equilibrium, an increase in the secondary system pressure results in steam relief via the steam generator safety valves.

When a SBLOCA occurs, depressurization of the RCS causes fluid to flow into the loops from the pressurizer, resulting in a pressure and level decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure reactor trip setpoint. This setpoint is 1846 psia but was conservatively modeled as 1840 psia. LOOP is assumed to occur coincident with reactor trip. A SI signal is generated when the pressurizer low-pressure SI setpoint, conservatively modeled as 1700 psia, is reached. Safety injection is delayed 27 seconds after pressurizer pressure decreases to the low pressure setpoint. This delay accounts for signal initiation, diesel generator startup and emergency power bus loading consistent with the assumed loss of offsite power coincident with reactor trip, as well as the time involved in aligning the valves and bringing the HHSI and LHSI pumps up to full speed. These countermeasures limit the consequences of the accident in two ways.

1. Reactor trip and borated water injection supplement void formation, causing a rapid reduction of nuclear power to a residual level that corresponds to the delayed fission and fission product decay. The boron content of the injection water from the RWST and accumulators is not assumed in the SBLOCA analysis.

In addition, the insertion of rod cluster control assemblies (RCCAs) subsequent to the reactor trip signal, while assuming the most reactive RCCA is stuck in the full out position, is assumed in the SBLOCA analysis. A rod drop time of 2.7 seconds, and an additional 2 seconds for the signal processing delay time are assumed. Therefore, a total delay time of 4.7 seconds from the time of reactor trip signal to rod insertion to the dashpot is used in the SBLOCA analysis.

2. Injection of borated water ensures sufficient flooding of the core to prevent excessive cladding temperatures.

During the earlier part of the small break transient (prior to the assumed loss of offsite power coincident with reactor trip), the loss of flow through the break is not sufficient to overcome the positive core flow maintained by the reactor coolant pumps. During this period, upward flow through the core is maintained. However, following the reactor coolant pump trip (due to a LOOP) and subsequent pump coastdown, a period of partial core uncovery occurs. Ultimately, the small break transient analysis is terminated when the ECCS flow provided to the RCS exceeds the break flowrate.

The core heat transfer mechanisms associated with the small break transient include the break itself, the injected ECCS water, and the heat transferred from the RCS to the steam generator secondary side. Although main feedwater (MFW) isolation is initiated by the SI signal, it is conservatively assumed in the analysis that MFW isolation occurs 7 seconds following the reactor trip signal: 2 seconds for signal delay time and 5 seconds for main feedwater control valve stroke time. A continuous supply of makeup water is also provided to the secondary side using the auxiliary feedwater system (AFWS). AFW flow from one motor-driven AFW pump and the turbine-driven AFW pump is assumed. AFWS actuation is conservatively assumed to occur 60 seconds after the SI signal. The motor-driven AFW pump is started by the SI signal, and the turbine-driven AFW pump is started by the RCP bus loss of voltage. AFWS actuation by the SI signal is conservative since the SI signal occurs after loss of offsite power (at reactor trip). The heat transferred to the secondary side of the steam generator aids in the reduction of the RCS pressure.

Should the RCS depressurize to approximately 585 psig (minimum), as in the case of the limiting 3-inch break and the 4-inch and 6-inch breaks, the cold leg accumulators begin to inject borated water into the reactor coolant loops. In the case of the 2-inch break however, the transient is terminated without the aid of accumulator injection.

EVALUATIONS

An evaluation was also performed to show that the single failure assumption of LOOP with the failure of an emergency power train is more limiting for SBLOCA than an alternate single failure scenario in which offsite power is not lost and one emergency power train fails. This evaluation is documented in Section 4.1.2.5 of Reference 7 and has been determined to be applicable to the SBLOCA analysis with Model 54F RSGs.

4.1.2.4 Acceptance Criteria for Analyses/Evaluations

The acceptance criteria for the LOCA are described in 10 CFR 50.46 (Reference 1) as follows:

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

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. 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.

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

5. 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.

Criteria 1 through 3 are explicitly covered by the SBLOCA analysis at RSG conditions.

For Criterion 4, the appropriate core geometry is modeled in the analysis. The results based on this geometry satisfy the PCT criterion of 10 CFR 50.46 and, consequently, demonstrate that the core remains amenable to cooling.

For Criterion 5, Long-Term Core Cooling (LTCC) considerations are not directly applicable to the SBLOCA transient, but are assessed in Section 4.1.3 as part of the evaluation of ECCS performance.

4.1.2.5 Results

To determine the conditions that produce the most limiting SBLOCA case (as determined by the highest calculated peak cladding temperature), a total of seven cases are examined. These cases include the investigation of variables including upflow/downflow, break size, and RCS temperature to ensure that the most severe postulated SBLOCA event is analyzed. The following discussions provide insight into the analyzed conditions.

Each unit at each end of the full power temperature window is analyzed for the 3-inch break, which was expected to be limiting for the Farley units. From Table 4.1.2-2, the configuration with the highest PCT, with respect to unit and core average temperature, is used for break size sensitivity calculations. In this analysis, Unit 1 with the high core average temperature was found to be limiting. The next set of calculations confirm that the limiting break size continues to be a 3-inch break, as shown in Table 4.1.2-3. All calculations shown in Tables 4.1.2-2 and 4.1.2-3 were performed assuming ZIRLO™ cladding at BOL conditions (0 MWD/MTU).

The results of Reference 8 demonstrate that the cold leg break location is limiting with respect to postulated cold leg, hot leg, and pump suction leg break locations. The PCT results are shown in Table 4.1.2-2 and Table 4.1.2-3. Inherent in the limiting small break analysis are several input assumptions (see Section 4.1.2.2 and Table 4.1.2-1), while Table 4.1.2-5 provides the key transient event times.

A summary of the transient response for the limiting case is shown in Figures 4.1.2-1 through 4.1.2-12. These figures present the response of the following parameters:

- RCS Pressure
- Core Mixture Level
- Peak Cladding Temperature
- Top Core Node Vapor Temperature
- Pumped SI Mass Flowrate for the Intact and Broken Loops
- Cold Leg Break Mass Flowrate
- Hot Spot Rod Surface Heat Transfer Coefficient
- Hot Spot Fluid Temperature
- Intact Loop Accumulator Flow
- Primary Side and Intact Loop Secondary Side Pressure
- Intact Loop Cold Leg Nozzle Liquid Mass Flowrate
- Intact Loop Cold Leg Nozzle Vapor Mass Flowrate

Upon initiation of the limiting 3-inch break, there is an initial rapid depressurization of the RCS followed by a intermediate equilibrium at around 1200 psia, which is then followed by a gradual depressurization past the accumulator injection setpoint (Figure 4.1.2-1). During the initial period of the small break transient, the effect of the break flowrate is not sufficient to overcome the flowrate maintained by the reactor coolant pumps as they coast down. As such, normal upward flow is maintained through the core and core heat is adequately removed. Following reactor trip, the removal of the heat generated as a result of fission products decay is accomplished via a two-phase mixture level covering the core. From the core mixture level and cladding temperature transient plots for the 3-inch break calculations given in Figures 4.1.2-2 and 4.1.2-3, respectively, it is seen that the peak cladding temperature occurs near the time when the core is most deeply uncovered and the top of the core is being cooled by steam. This time is characterized by the highest vapor superheating above the mixture level (refer to Figure 4.1.2-4).

A comparison of the flow provided by the safety injection system (SIS) to the intact and broken loops to the total cold leg break mass flowrate at the end of the transient (Figures 4.1.2-5 and 4.1.2-6), indicates that at the time the transient was terminated, the total SI flowrate that was delivered to the intact and broken loops exceeds the mass flowrate out the break. At 3000 seconds, the pumped SI flowrate is about 64.5 lbm/sec while the break flowrate is about 61.0 lbm/sec, yielding a net increase in system inventory.

Figures 4.1.2-7 and 4.1.2-8 provide additional information on the hot rod surface heat transfer coefficient at the hot spot and fluid temperature at the hot spot, respectively. Figures 4.1.2-9, 4.1.2-10, 4.1.2-11, and 4.1.2-12 show additional information on the intact loop accumulator flow, primary side and intact loop secondary side pressure, intact loop cold leg nozzle liquid mass flowrate, and intact loop cold leg nozzle vapor mass flowrate for the limiting 3-inch break high T_{avg} case, respectively.

The 10 CFR 50.46 criteria continue to be satisfied beyond the end of the calculated transient due to the following conditions:

1. The RCS pressure is gradually decaying.

2. The net mass inventory is increasing.

3. The core mixture level is recovered.

4. As the RCS inventory continues to gradually increase, the core mixture level will continue to increase and the fuel cladding temperatures will continue to decline, indicating that the temperature excursion is terminated.

ADDITIONAL BREAK CASES

Studies documented in Reference 8 have determined that the limiting small break transient occurs for breaks of less than 10 inches in diameter. To ensure that the 3-inch diameter break was the most limiting, calculations were also performed with break equivalent diameters of 2 inches, 4 inches, and 6 inches. The results of the limiting configuration case (3 inches) is given in Table 4.1.2-2, while the results of the break spectrum cases are given in Tables 4.1.2-3 and 4.1.2-5. For the limiting configuration calculations for 3-inch breaks, plots of the RCS pressure transient core mixture level, and PCT are given in Figures 4.1.2-13 through 4.1.2-15 for Unit 1 low T_{avg}, Figures 4.1.2-16 through 4.1.2-18 for Unit 2 high T_{avg} and Figures 4.1.2-19 through 4.1.2-21 for Unit 2 low T_{avg}.

The PCTs for the 2-inch, 4-inch, and 6-inch breaks are 1069°F, 1599°F, and 1035°F respectively. As shown in Table 4.1.2-3, these PCTs are less than the limiting 3-inch break case.

LIMITING TEMPERATURE CONDITIONS

Reduced operating temperature typically results in a PCT benefit for the SBLOCA. However, due to the complex nature of SBLOCA transients, there have been some instances where more limiting results have been observed for the reduced operating temperature case. For this reason, the SBLOCA transient based on a lower bound RCS vessel average temperature is analyzed.

For Farley, the temperature window analyzed is based on a nominal vessel average temperature range of 567.2° to 577.2°F with ±6.0°F to bound uncertainties. A sensitivity analysis for the vessel average temperature and upflow/downflow configuration is performed based on the limiting 3-inch break case from the break spectrum analyses previously described. The analysis shows that the Unit 1 high T_{avg} case is limiting.

TIME IN LIFE CALCULATIONS

Since burst at beginning of life (BOL) conditions were not obtained for the ZIRLO™-clad fuel, additional cases have been run as a function of time in life to isolate the point at which rod burst occurs. At this point, there is a PCT excursion due to the Zirc-water reaction at the burst location and blockage in the flow channel. This PCT excursion is usually more limiting than the BOL PCT and becomes more severe as the BOL PCT increases. For ZIRLO™-clad fuel, burst occurs at 6000 MWD/MTU, and the resulting PCT is 2011°F for a 3-inch break for Unit 1, indicating that the net burst and blockage/time in life penalty is approximately 128°F based upon explicit calculations. To allow for insertion of annular pellet fuel, an additional 10°F PCT penalty plus the associated 9°F penalty for burst and blockage/time in life effects have been assessed, resulting in a limiting PCT of 2030°F for a 3-inch break for Unit 1. The PCT plot for this case is presented as Figure 4.1.2-22.

Since ZIRLO™- and Zirc-clad fuel have different physical characteristics, as modeled by the SBLOCTA code, explicit calculations for Zirc-clad fuel are performed. For Zirc-clad fuel, a PCT of 1887°F was calculated with no rod burst at BOL conditions for a 3-inch break at high T_{avg} conditions for Unit 1. However, no new Zirc-clad fuel is expected to be inserted into the core. All of the Zirc-clad fuel will be burned for at least one cycle, if not more, if ZIRLO™-clad fuel is implemented prior to the RSG. The Zirc-clad minimum, core-wide, fuel-pin burnup is expected to be well in excess of 6000 MWD/MTU. Therefore, the minimum burnup considered for time in life effects is 6000 MWD/MTU. The most limiting PCT calculation for Zirc-clad fuel was found to be 1945°F with rod burst at 6000 MWD/MTU (see Figure 4.1.2-23). With this case, the ZIRLO™-clad fuel will be considered more limiting with a PCT of 2011°F in comparison to the 1945°F PCT. This confirmation will have to be explicitly verified as part of the reload safety analysis checklist (RSAC) process when the ZIRLO™-clad fuel is being implemented with the RSG. If this burnup criterion can be satisfied during the reload, as is expected, then no additional PCT calculations will be needed for Zirc-clad fuel.

The fuel temperatures/pressures used in these calculations account for any modifications to the helium release model deemed necessary. This analysis is performed using the most limiting temperature/pressure data (including Zirc versus ZIRLO™ cladding and 1.5 × 100 psig backfill integral fuel burnable absorbers (IFBA) versus non-IFBA) as calculated for VANTAGE 5 (V5) fuel. Since the low parasitic (LOPAR) fuel $F_{\Delta H}$ is more restrictive than the V5 $F_{\Delta H}$ and since LOPAR fuel is expected to be placed in non-limiting power locations, no explicit calculations for LOPAR fuel have been or need to be performed as part of the RSG program. Since LOPAR fuel is to be loaded in any given cycle, this will be handled as part of the normal reload evaluation process.

4.1.2.6 Conclusions

A break spectrum at the limiting vessel average temperature and upflow/downflow configuration was performed. Peak cladding temperatures of 1069°F, 1883°F, 1599°F , and 1035°F were calculated for the 2-inch, 3-inch, 4-inch, and 6-inch cold leg breaks, respectively, at BOL, thus identifying the 3-inch equivalent diameter break as limiting. The sensitivity to vessel average temperature and upflow/downflow configuration yields a limiting peak cladding temperature of 1883°F for the Unit 1 high T_{avg} case. Therefore, the 3-inch equivalent diameter cold leg break, high nominal vessel average temperature for Unit 1, is the limiting case. Addition of annular pellet blankets and time in life effects yield a limiting PCT of 2030°F for ZIRLO™-clad fuel. Beyond 6000 MWD/MTU, evaluations have been performed to determine that PCT for Zirc-clad fuel is bounded by PCT for ZIRLO™-clad fuel.

The analyses presented in this section show that the accumulator and HHSI and LHSI subsystems of the ECCS, together with the heat removal capability of the RSG, provide sufficient core heat removal capability to maintain the calculated peak cladding temperatures below the required limit of 10 CFR 50.46.

4.1.2.7 References

1. *Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors*, 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3, January 1974, as amended in Federal Register, Volume 53, September 1988

2. Meyer, P. E., *NOTRUMP - A Nodal Transient Small Break and General Network Code*, WCAP-10079-P-A (Proprietary) and WCAP-10080-NP-A (Non-Proprietary), August 1985

3. Lee, N. et al., *Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code*, WCAP-10054-P-A (Proprietary) and WCAP-10081-NP-A (Non-Proprietary), August 1985

4. *Generic Evaluation of Feedwater Transients and Small Break Loss of Coolant Accidents in Westinghouse - Designed Operating Plant*, NUREG-0611, January 1980

5. Bordelon, F. M. et al., *LOCTA-IV Program: Loss of Coolant Transient Analysis*, WCAP-8301 (Proprietary) and WCAP-8305 (Non-Proprietary), June 1974

6. Thompson, C. M., et al., *Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model*, WCAP-10054-P-A (Proprietary) and WCAP-10081-NP (Non-Proprietary), Addendum 2, Revision 1, July 1997

7. *Farley Nuclear Plant Units 1 and 2 Power Uprate Project NSSS Licensing Report*, WCAP-14723 (Proprietary) and WCAP-14724 (Non-Proprietary), January 1997

8. Rupprecht, S. D. et al., *Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code*, WCAP-11145-P-A (Proprietary) and WCAP-11372-A (Non-Proprietary), October 1986

Table 4.1.2-1 Input Parameters Used in the SBLOCA Analysis	
Parameter	**Value**
Reactor Core Rated Thermal Power[1], (M'	2775
Peak Linear Power[1, 2], (kW/ft)	13.9
Total Peaking Factor (F) at Peak[2]	2.50
$F_{\Delta H}$	1.70
Fuel Array	17x17
Accumulator Water Volume[3], Nominal (ft^3/acc.)	980
Accumulator Gas Pressure, Minimum (psig)	585
Steam Generator Tube Plugging Level (%)[4]	20 peak
Thermal Design Flow per Loop, (gpm)	86,000
Vessel Average Temperature Uncertainties, (°F)	-6.0/+6.0 (Low/High)
Vessel Average Temperature Without Uncertainties, (°F)	567.2/577.2 (Low/High)
Reactor Coolant Pressure With Uncertainties, (psia)	2300
Minimum Auxiliary Feedwater flowrate, (gpm)	681

Notes:

(1) Two percent is added to this power to account for calorimetric error. Reactor coolant pump heat is not modeled in the SBLOCA analyses.

(2) This represents a power shape corresponding to a one-line segment peaking factor envelope, K(z), based on $F_Q = 2.50$.

(3) Does not include line volume of 45 ft^3.

(4) Maximum plugging level in all steam generators.

Table 4.1.2-2
SBLOCA Analysis BOL Fuel Cladding Results
Limiting Configuration Determination for 3-Inch Break

	Unit 1 High T_{avg}	Unit 2 High T_{avg}	Unit 1 Low T_{avg}	Unit 2 Low T_{avg}
Peak Cladding Temperature (°F)	1883	1792	1818	1847
Peak Cladding Temperature Location (ft)[1]	11.75	11.75	12.00	11.75
Peak Cladding Temperature Time (sec)	1345	1419	1478	1387
Local Zr/H_2O Reaction, Max (%)	4.57	3.54	3.95	4.49
Local Zr/H_2O Reaction Location (ft)[1]	11.75	11.75	11.75	11.75
Total Zr/H_2O Reaction (%)	< 1.0	< 1.0	< 1.0	< 1.0
Hot Rod Burst Time (sec)	No Burst	No Burst	No Burst	No Burst
Hot Rod Burst Location (ft)	N/A	N/A	N/A	N/A

Notes:

(1) From bottom of active fuel

Table 4.1.2-3
SBLOCA Analysis Fuel Cladding
Results Break Spectrum

	2-inch	**3-inch**	**4-inch**	**6-inch**
Peak Cladding Temperature (°F)	1069	1883	1599	1035
Peak Cladding Temperature Location (ft)[1]	11.00	11.75	11.50	10.50
Peak Cladding Temperature Time (sec)	1385	1345	729	334
Local Zr/H_2O Reaction, Max (%)	0.05	4.57	0.73	0.01
Local Zr/H_2O Reaction Location (ft)[1]	11.25	11.75	11.25	10.50
Total Zr/H_2O Reaction (%)	< 1.0	< 1.0	< 1.0	< 1.0
Hot Rod Burst Time (sec)	No Burst	No Burst	No Burst	No Burst
Hot Rod Burst Location (ft)	N/A	N/A	N/A	N/A

Notes:

(1) From bottom of active fuel

Table 4.1.2-4
SBLOCA Analysis Fuel Cladding Results
Burst/Time-in-Life Results For ZIRLO™ Cladding

	Unit 1 High T_{avg}
Peak Cladding Temperature (°F)	2030[2]
Peak Cladding Temperature Location (ft)[1]	12.00
Peak Cladding Temperature Time (sec)	1341
Local Zr/H_2O Reaction, Max (%)	11.88
Local Zr/H_2O Reaction Location (ft)[1]	12.00
Rod Burst Time (sec)	1339
Rod Burst Elevation (ft)[1]	12.00
Burnup (MWD/MTU)	6000

Notes:

(1) From bottom of active fuel

(2) This PCT includes a 10° assessment for addition of annular pellet blankets and 9° associated assessment for burst and blockage/time in life.

Table 4.1.2-5
SBLOCA Analysis Time Sequence of Events

	2-inch	3-inch	4-inch	6-inch
Break Occurs (sec)	0.0	0.0	0.0	0.0
Reactor Trip Signal (sec)	59.5	17.0	10.5	7.4
Safety Injection Signal (sec)	69.2	26.1	18.8	11.4
Top of Core Uncovered (sec)	1110	625	391	243
Accumulator Injection Begins (sec)	N/A(1)	1108	585	270
Peak Clad Temperature Occurs (sec)	1385	1345	729	334
Top of Core Covered (sec)	>8000(2)	>3000(2)	2675	365

Notes:

(1) System pressure never drops below the accumulator cut-in pressure (600 psia).

(2) Although the plots show the top of the core has not been fully recovered, the core level is steadily trending upward and total RCS mass is trending upward.

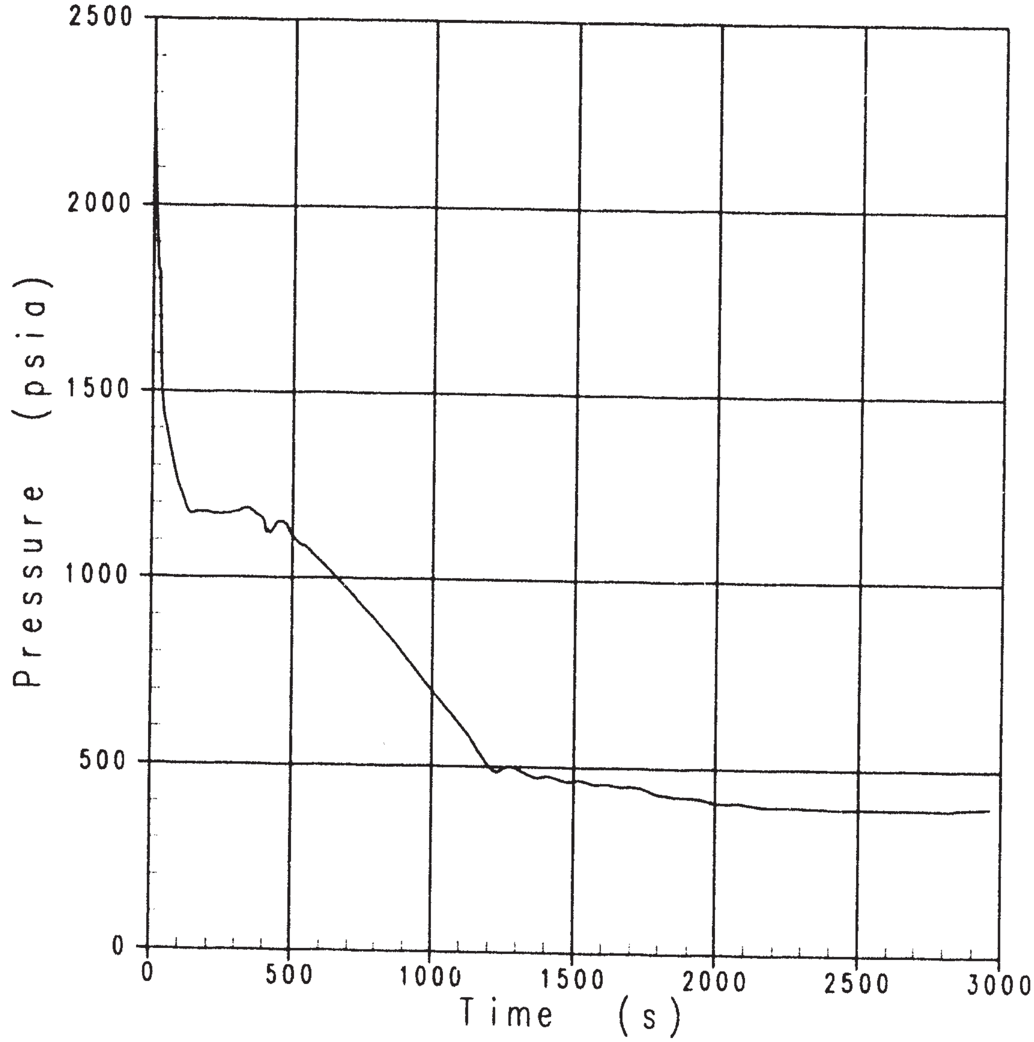


Figure 4.1.2-1
RCS Depressurization Transient, 3-Inch Break, High T_{avg}, Unit 1

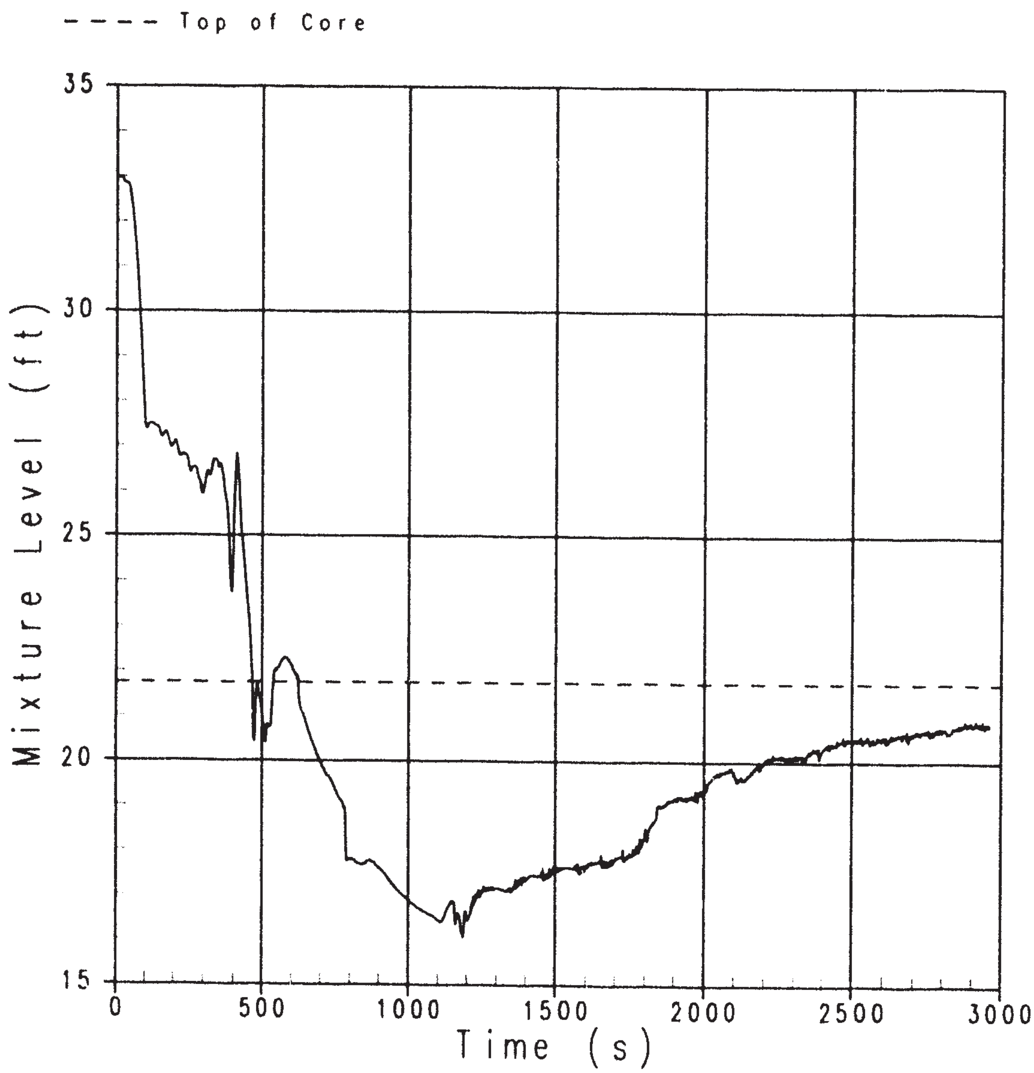


Figure 4.1.2-2
Core Mixture Level, 3-Inch Break, High T_{avg}, Unit 1

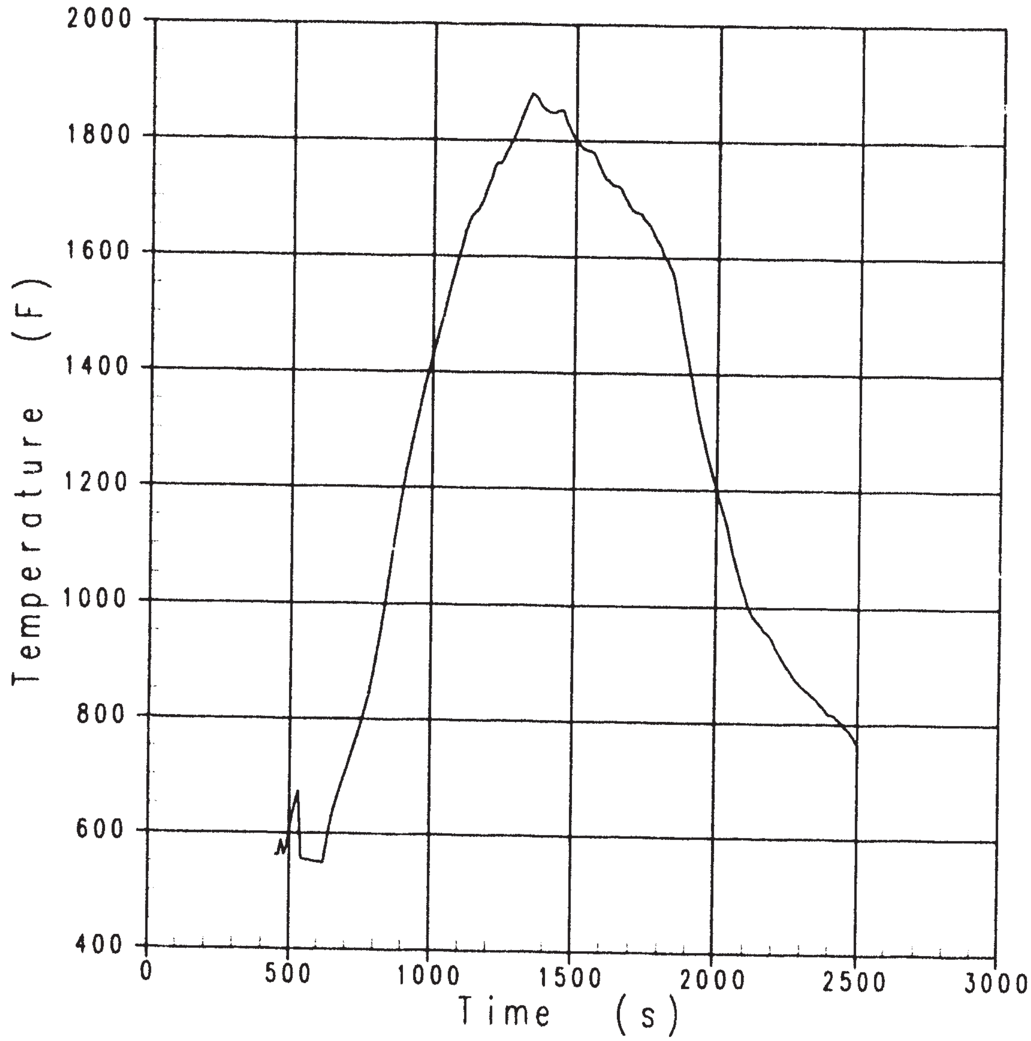


Figure 4.1.2-3
Peak Cladding Temperature - Hot Rod, 3-Inch Break, High T_{avg}, Unit 1

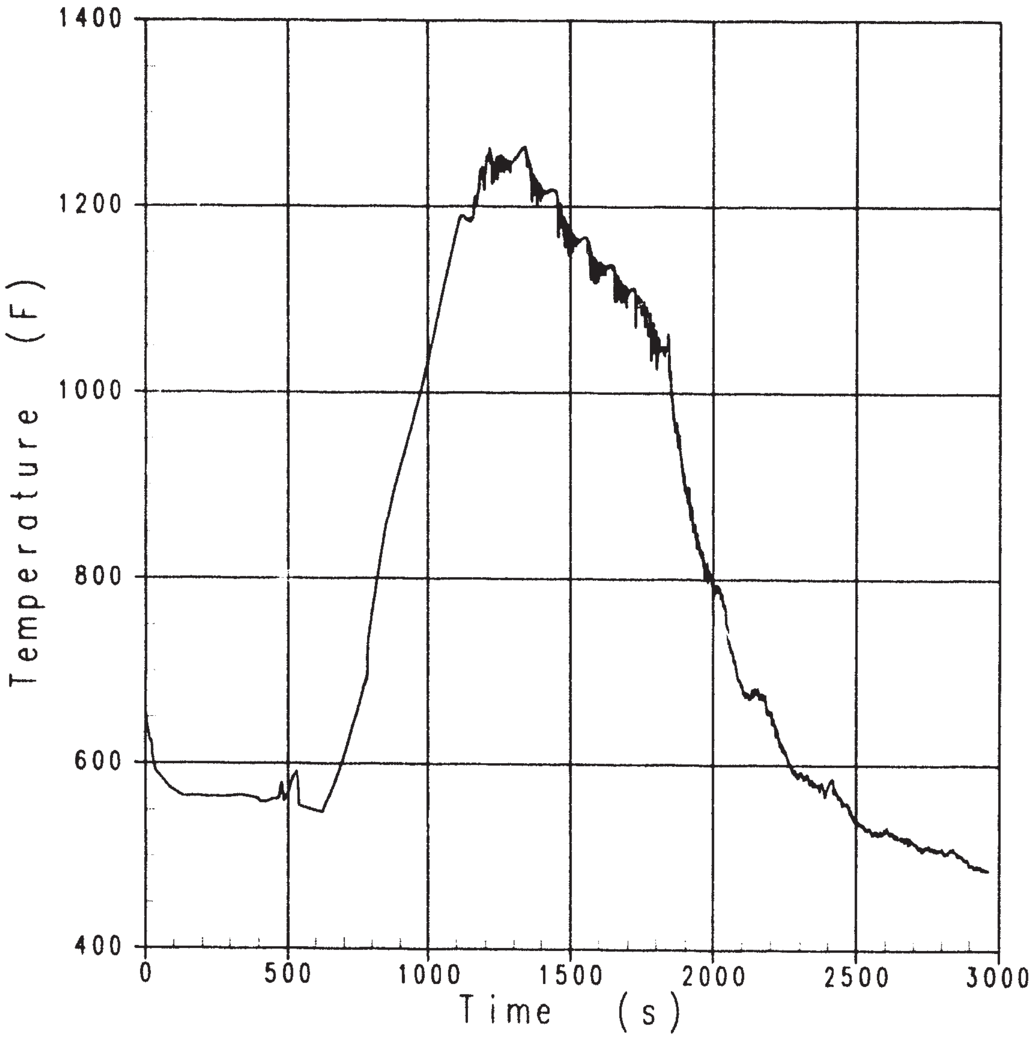


Figure 4.1.2-4
Top Core Node Vapor Temperature, 3-Inch Break, High T_{avg}, Unit 1

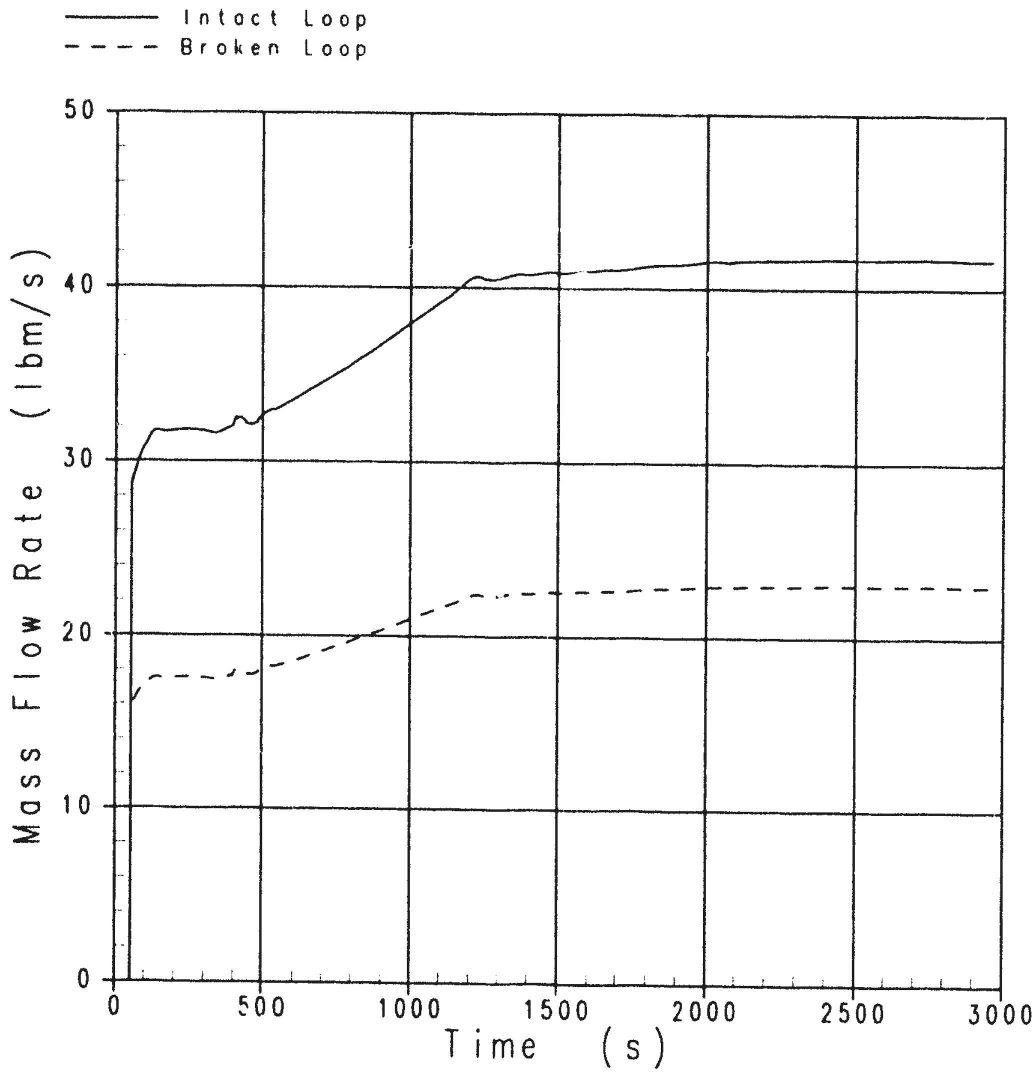


Figure 4.1.2-5
ECCS Pumped Safety Injection, 3-Inch Break, High T_{avg}, Unit 1

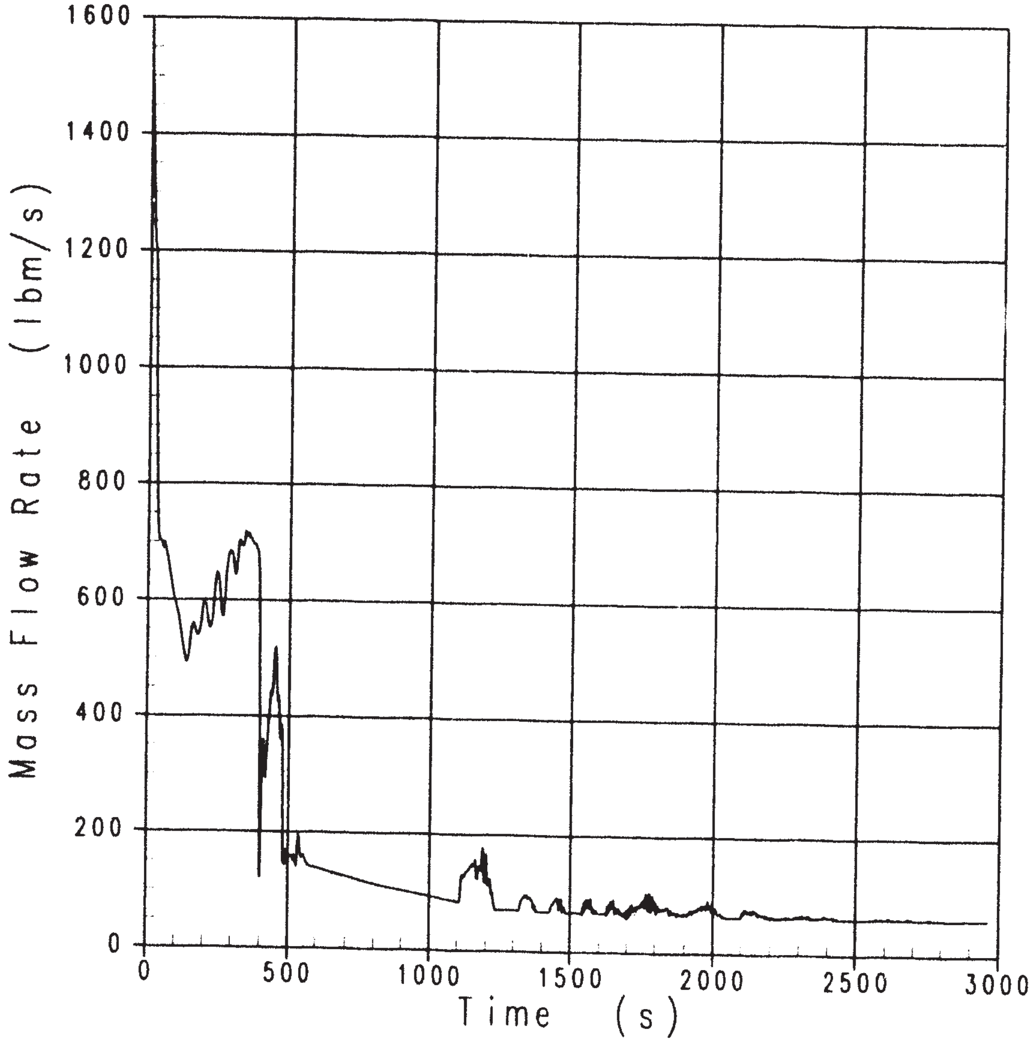


Figure 4.1.2-6
Cold Leg Break Mass Flow, 3-Inch Break, High T_{avg}, Unit 1

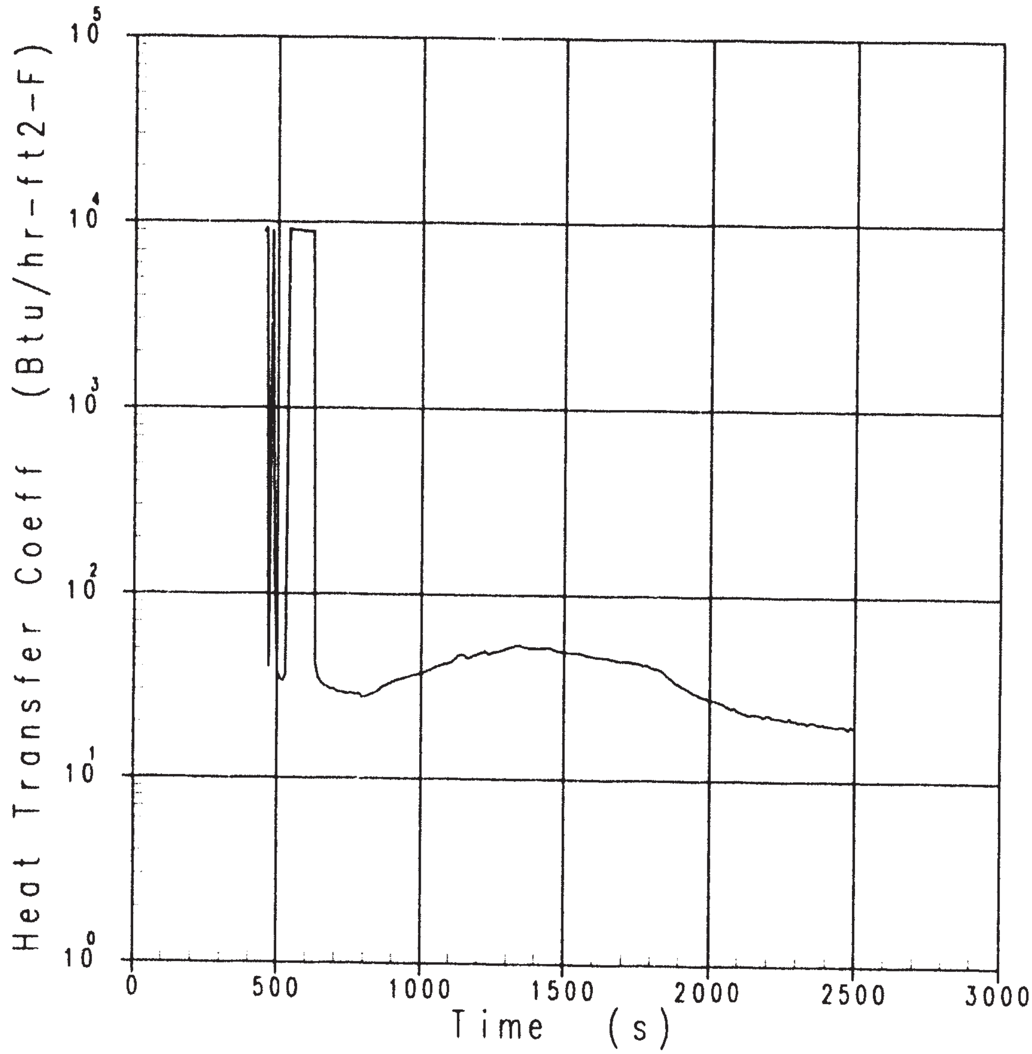


Figure 4.1.2-7
Hot Rod Surface Heat Transfer Coefficient Hot Spot, 3-Inch Break, High T_{avg}, Unit 1

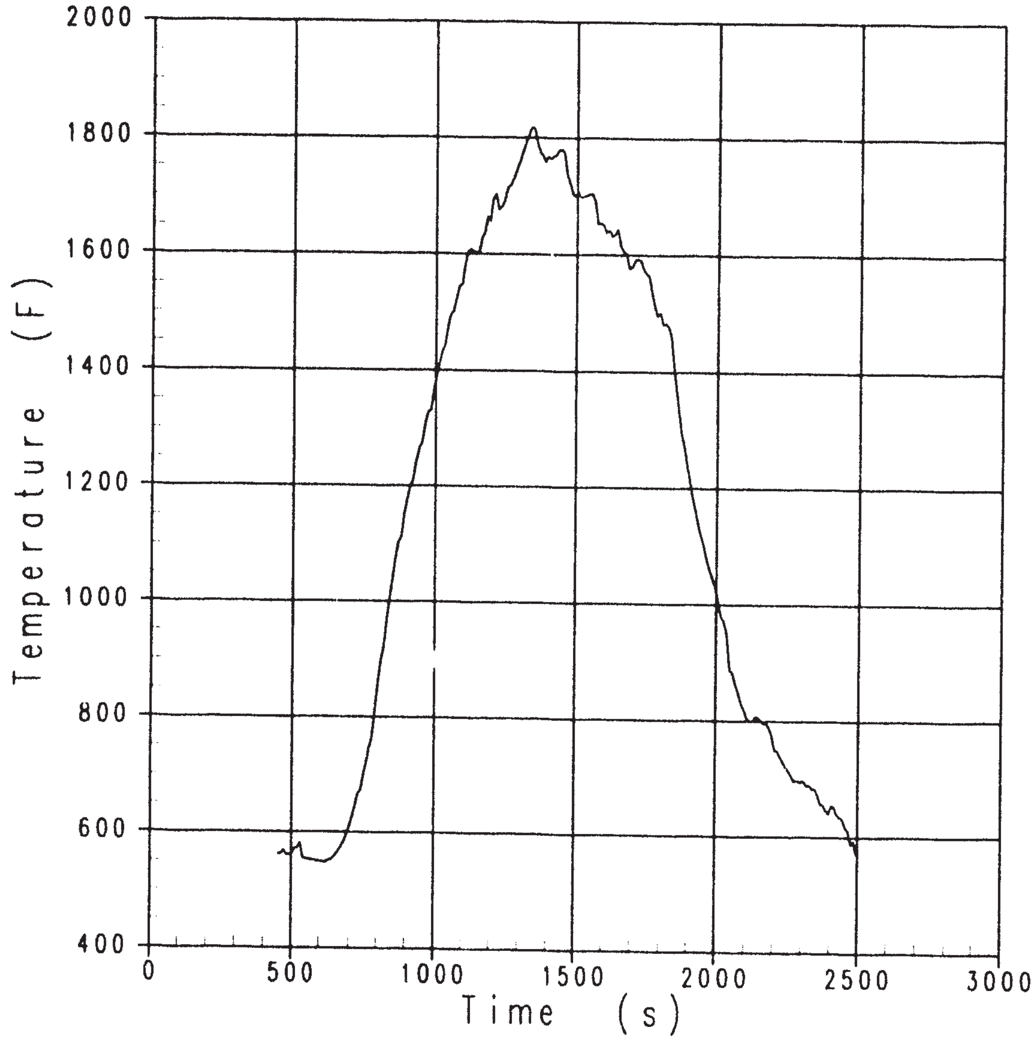


Figure 4.1.2-8
Fluid Temperature - Hot Spot, 3-Inch Break, High T_{avg}, Unit 1

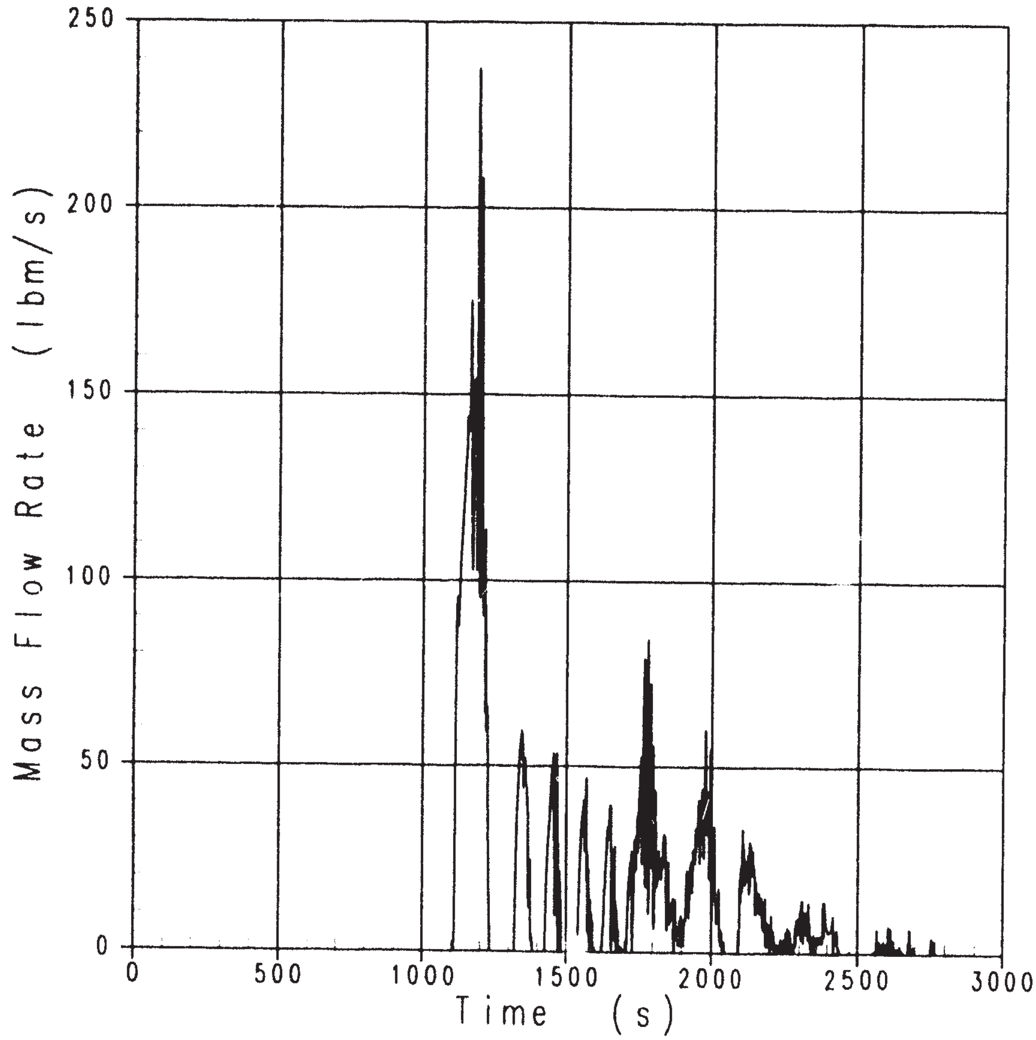


Figure 4.1.2-9
Intact Loop Accumulator Flow, 3-Inch Break, High T_{avg}, Unit 1

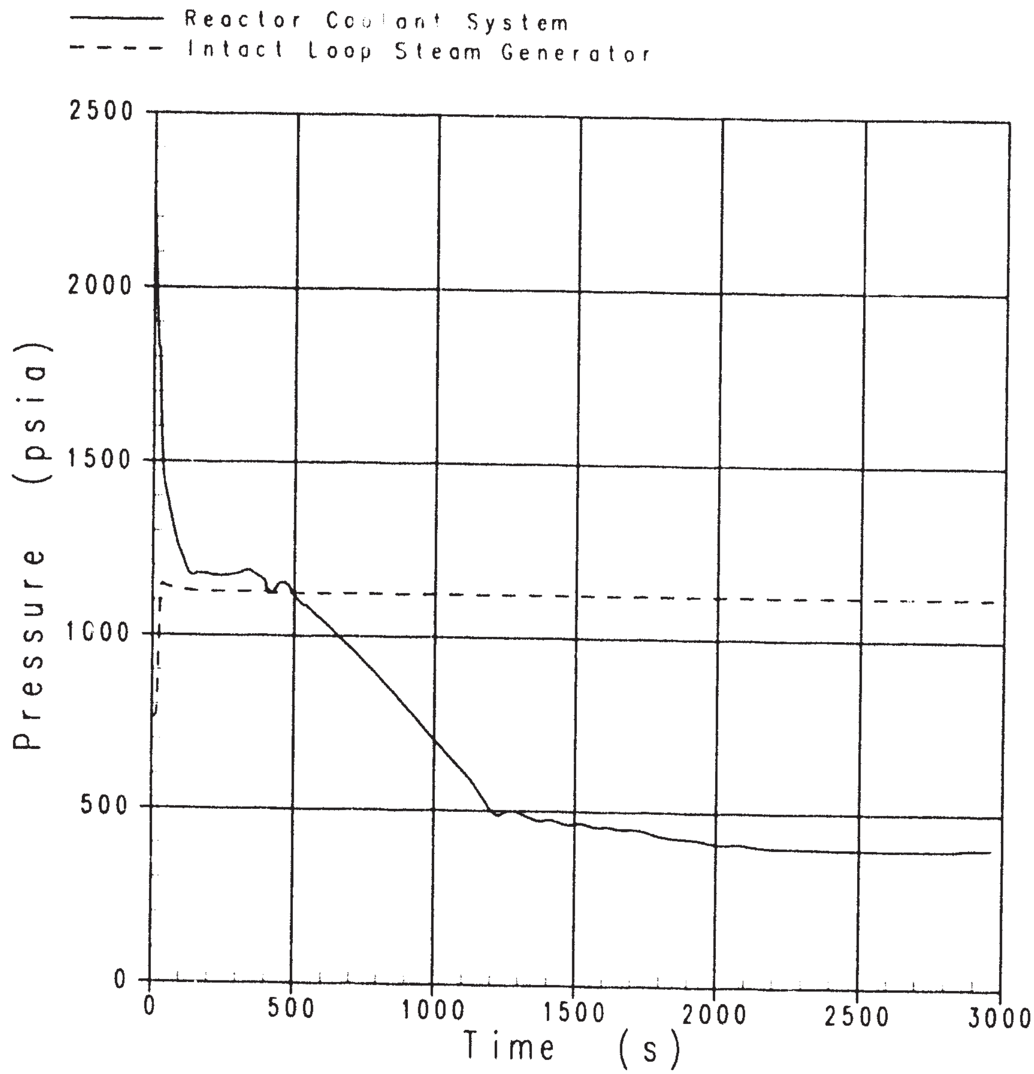


Figure 4.1.2-10
Primary Side and Intact Loop Secondary Side Pressure, 3-Inch Break, High T_{avg}, Unit 1

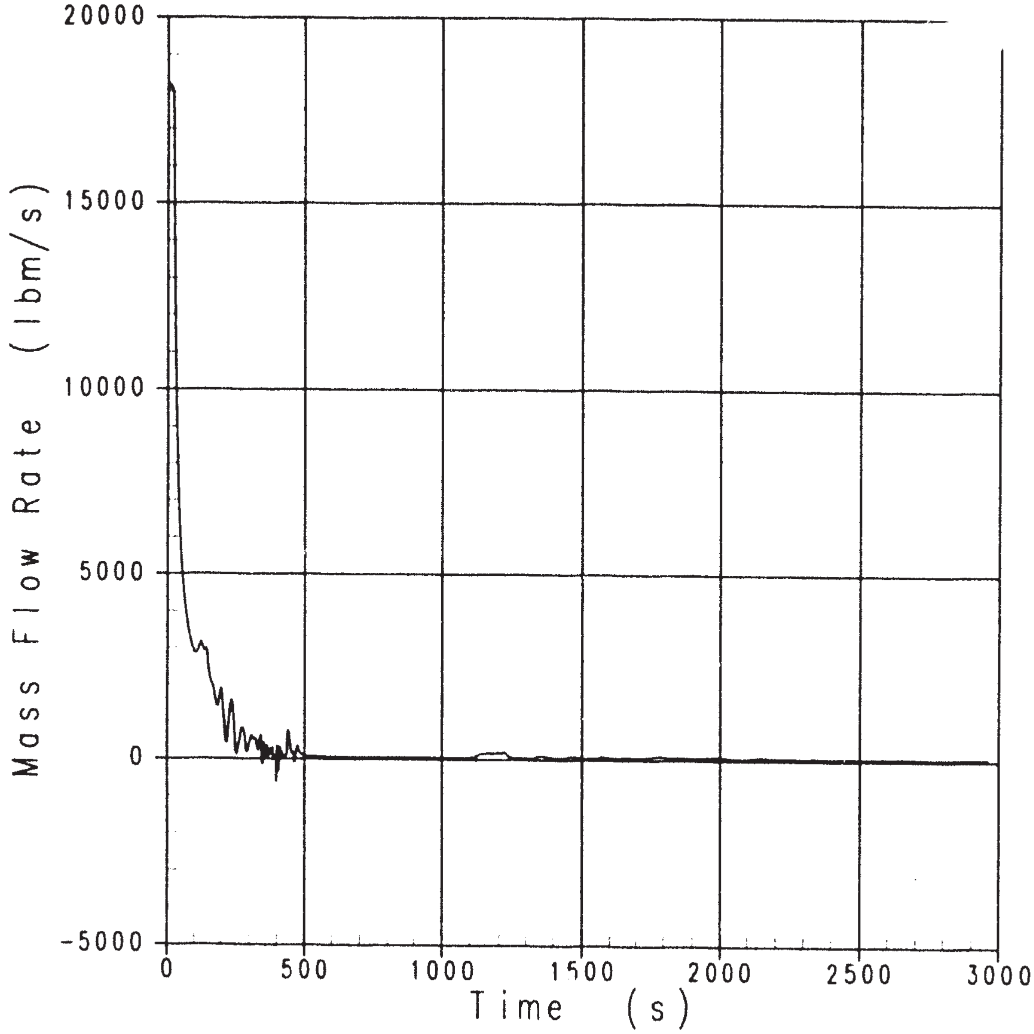


Figure 4.1.2-11
Intact Loop Cold Leg Nozzle Liquid Mass Flowrate, 3-Inch Break, High T_{avg}, Unit 1

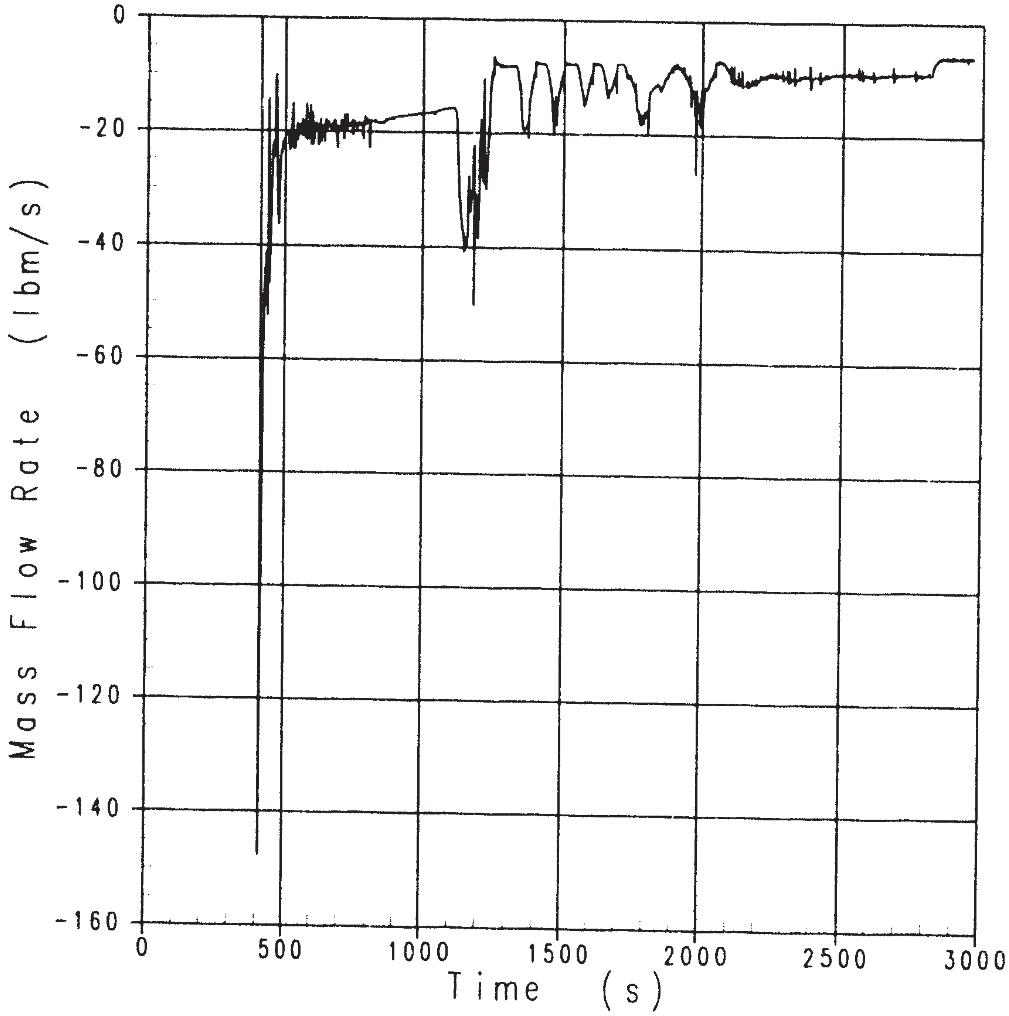


Figure 4.1.2-12
Intact Loop Cold Leg Nozzle Vapor Mass Flowrate, 3-Inch Break, High T_{avg}, Unit 1

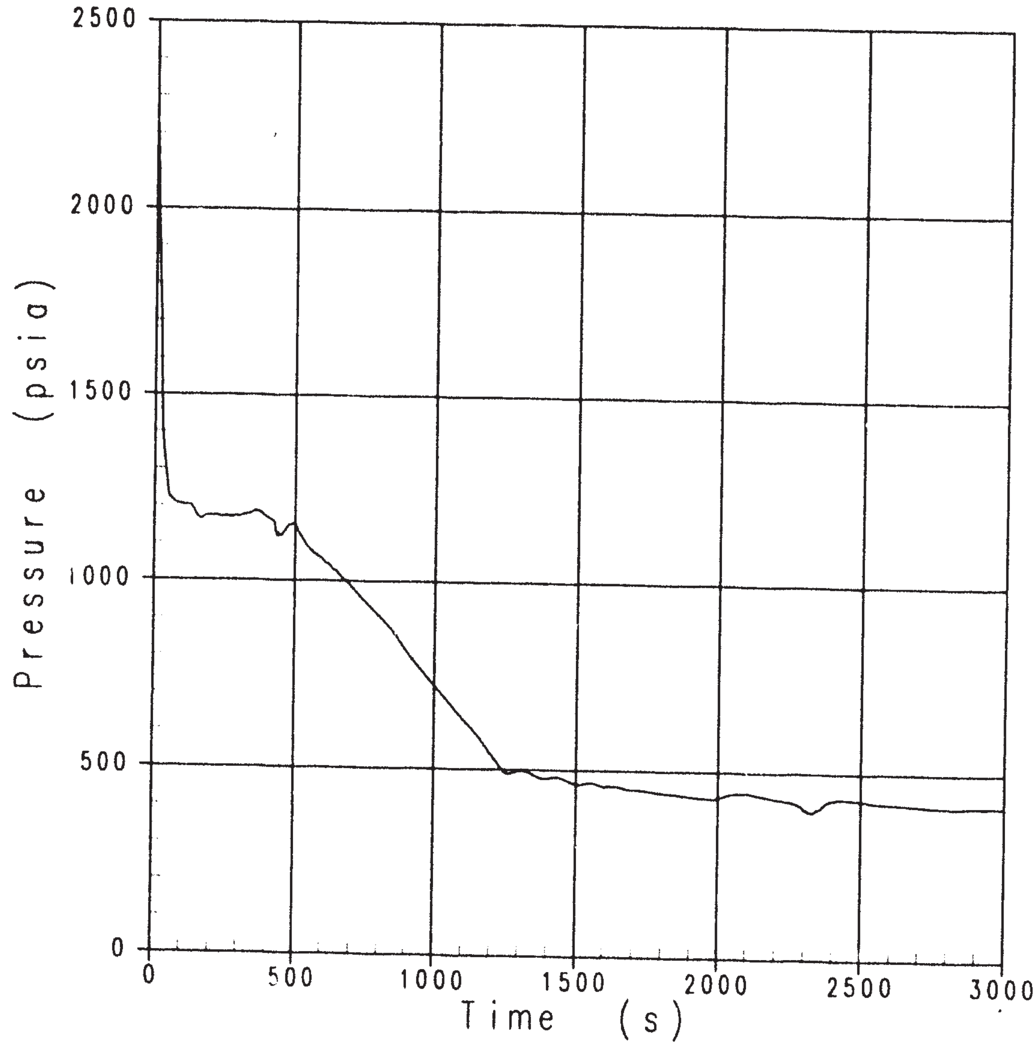


Figure 4.1.2-13
RCS Depressurization Transient, 3-Inch Break, Low T_{avg}, Unit 1

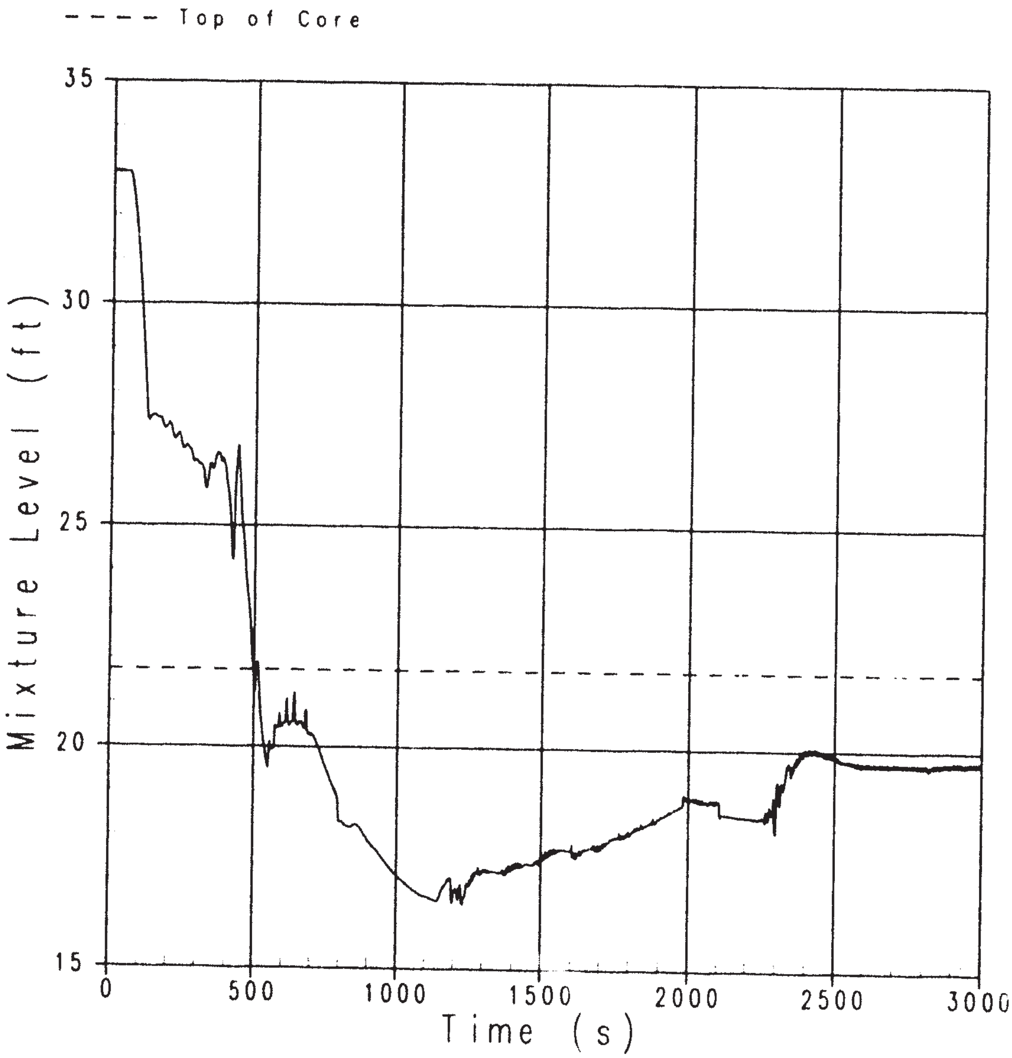


Figure 4.1.2-14
Core Mixture Level, 3-Inch Break, Low T_{avg}, Unit 1

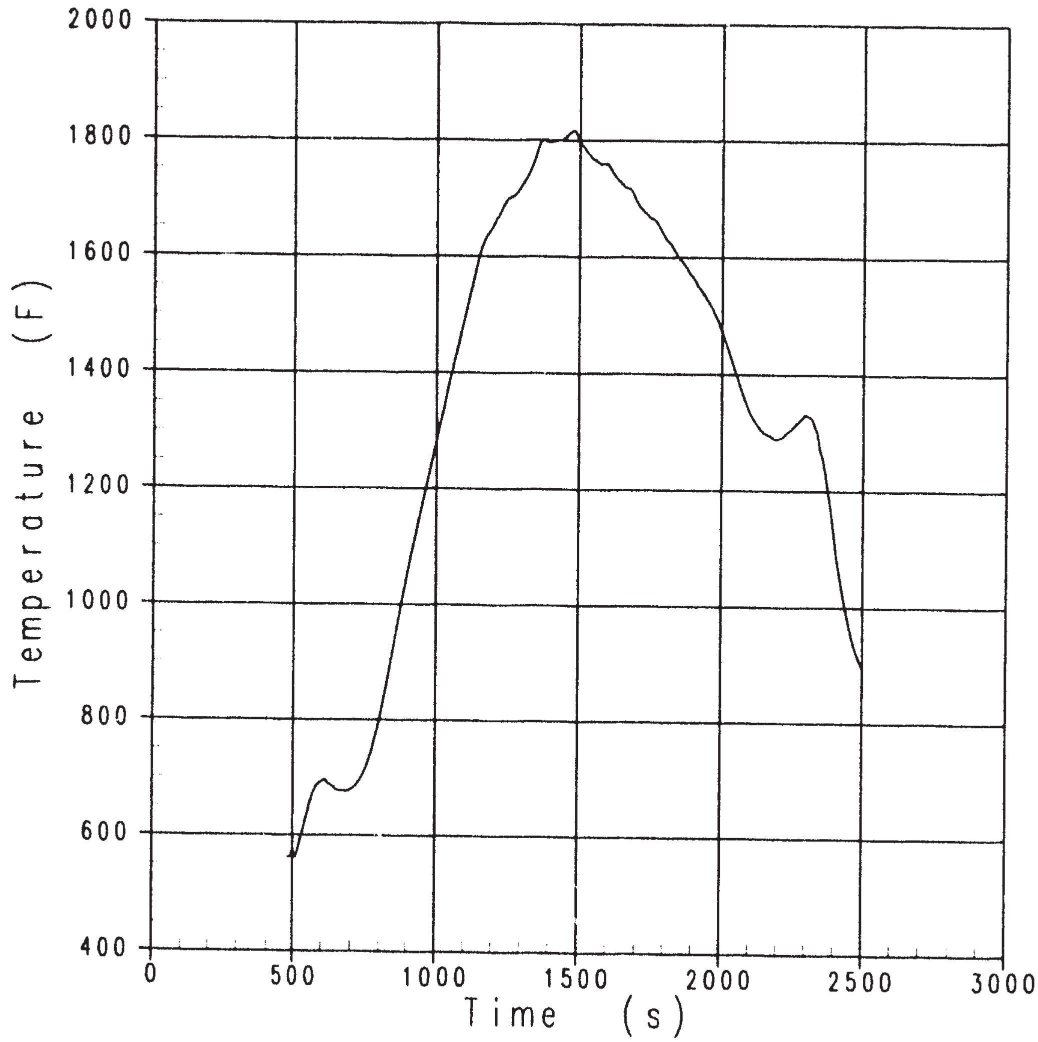


Figure 4.1.2-15
Peak Cladding Temperature - Hot Rod, 3-Inch Break, Low T_{avg}, Unit 1

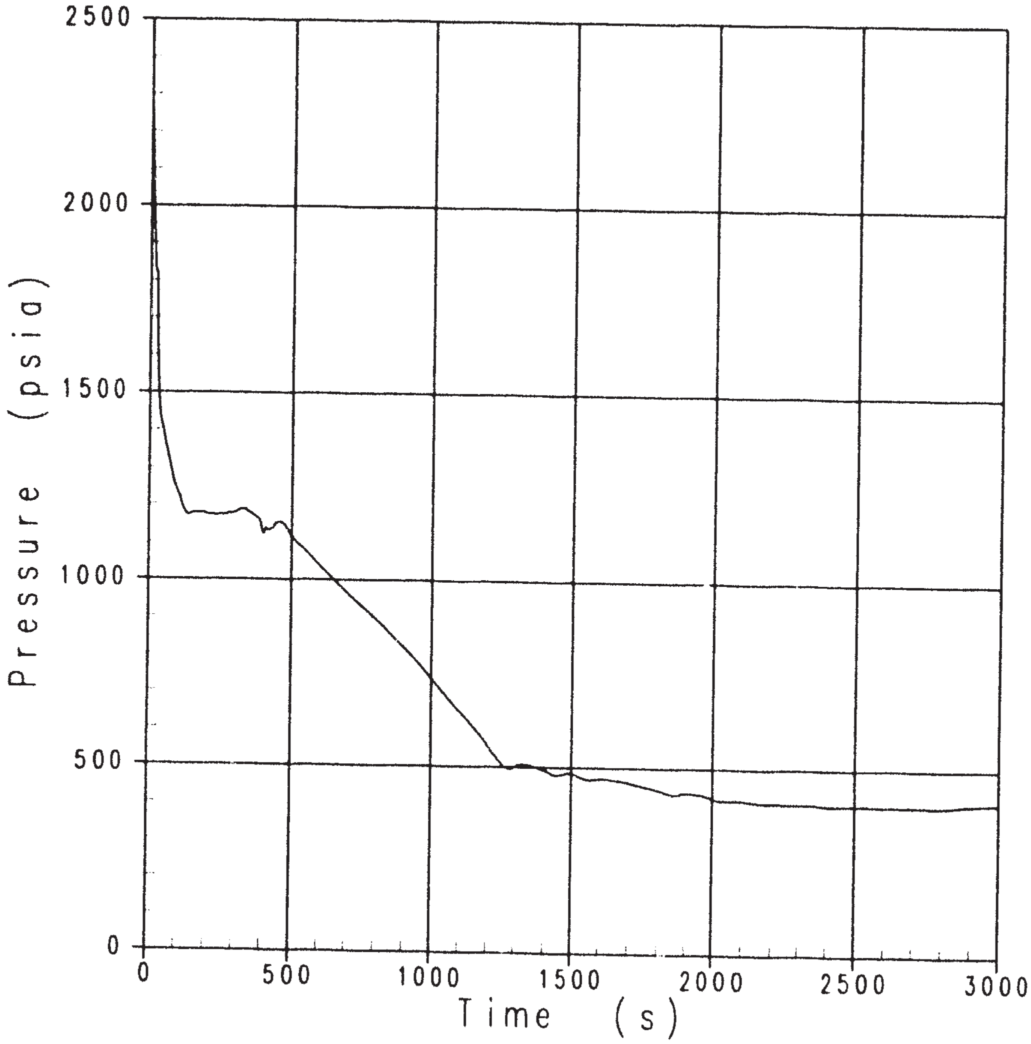


Figure 4.1.2-16
RCS Depressurization Transient, 3-Inch Break, High T_{avg}, Unit 2

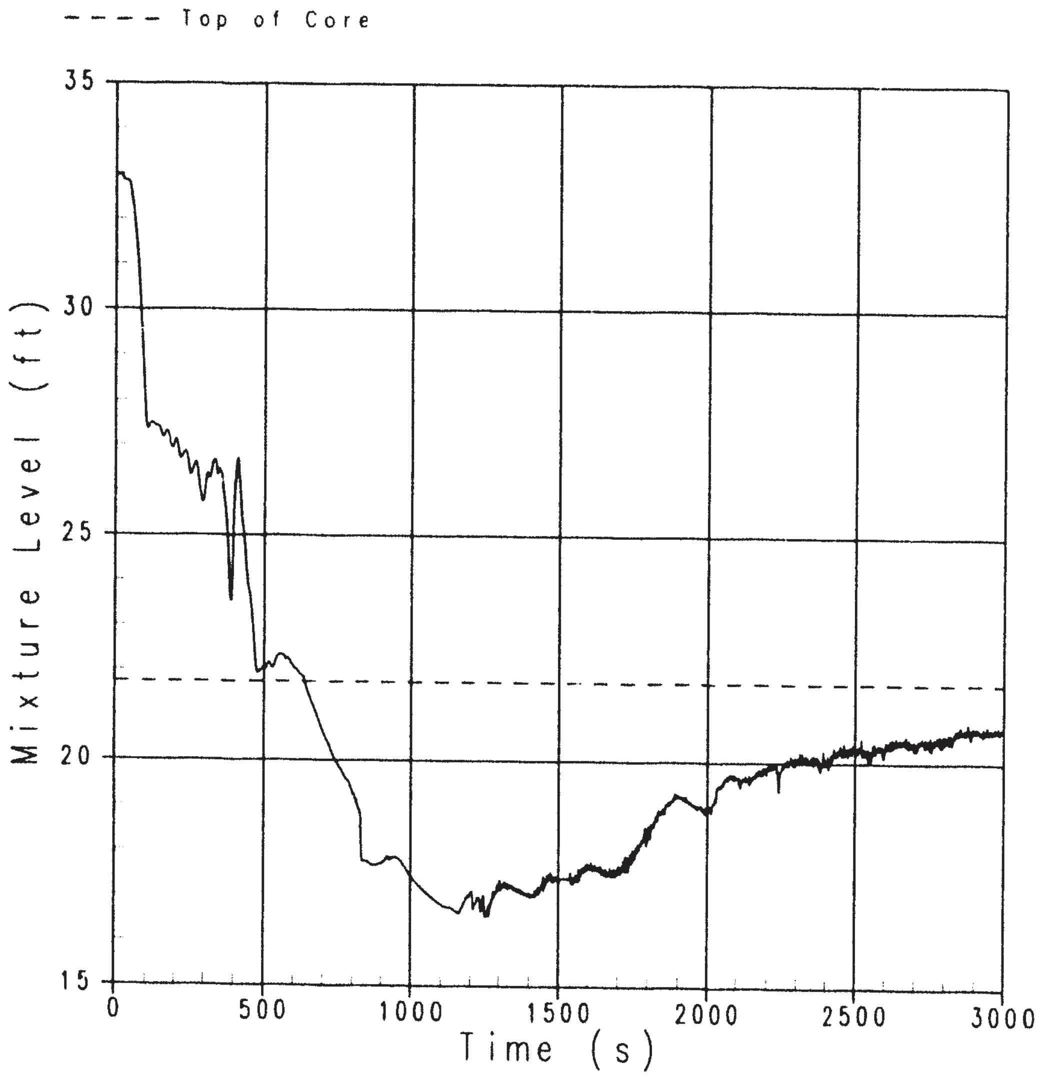


Figure 4.1.2-17
Core Mixture Level, 3-Inch Break, High T_{avg}, Unit 2

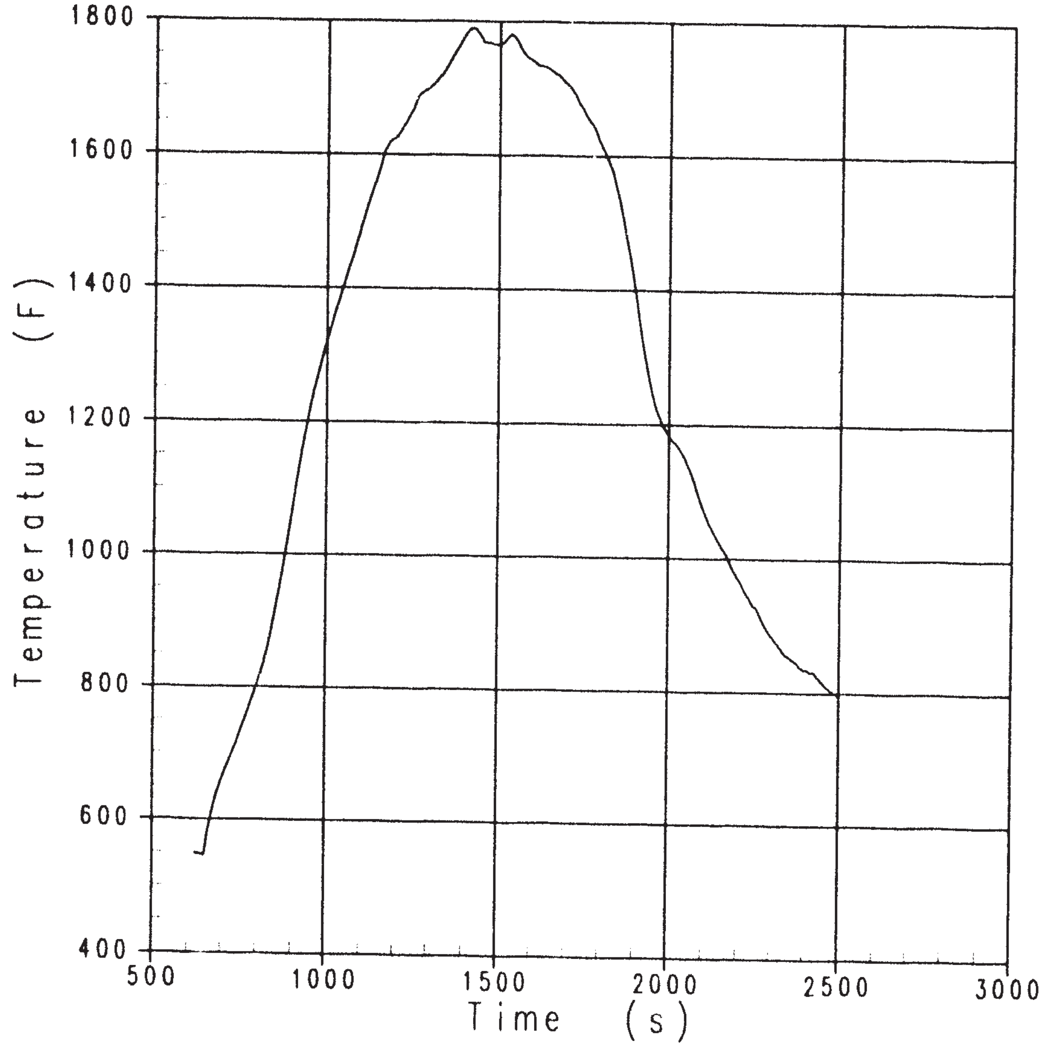


Figure 4.1.2-18
Peak Cladding Temperature - Hot Rod, 3-Inch Break, High T_{avg}, Unit 2

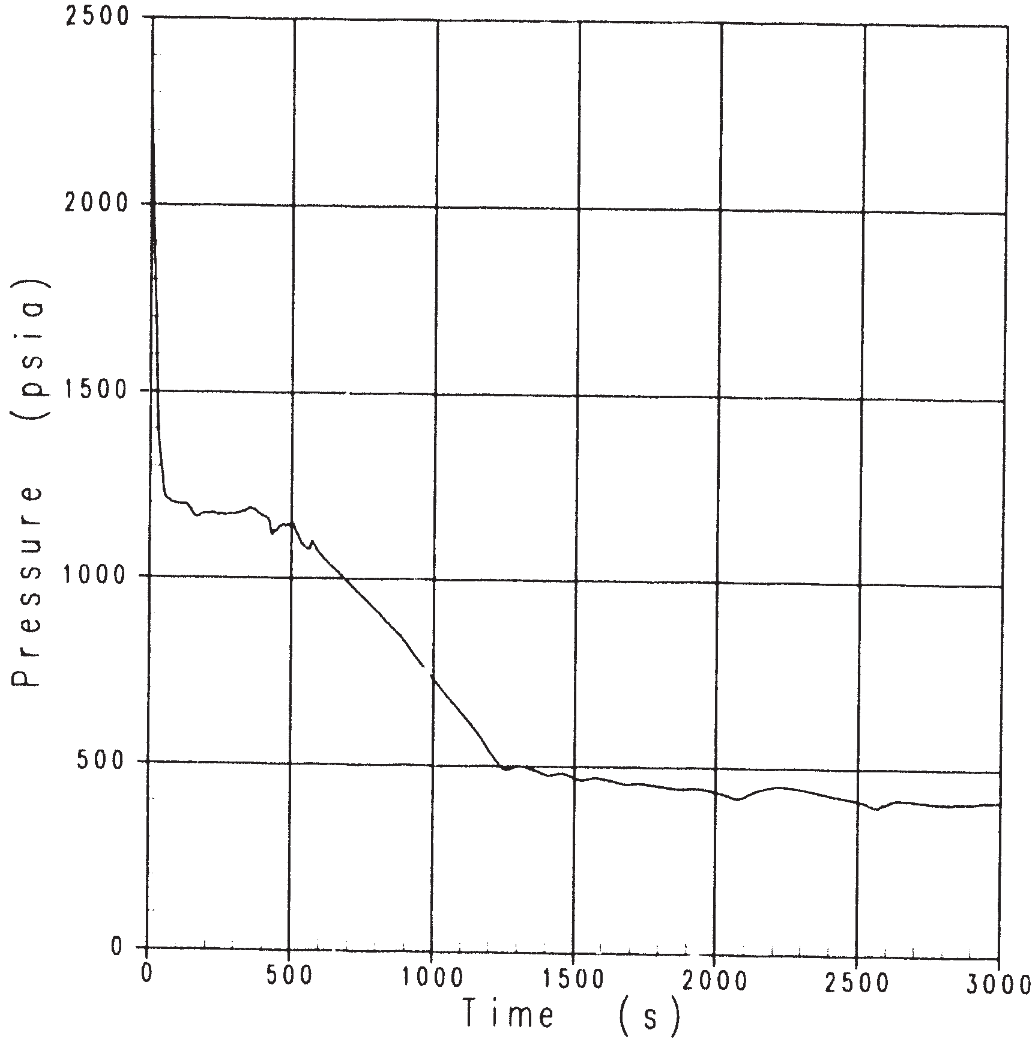


Figure 4.1.2-19
RCS Depressurization Transient, 3-Inch Break, Low T_{avg}, Unit 2

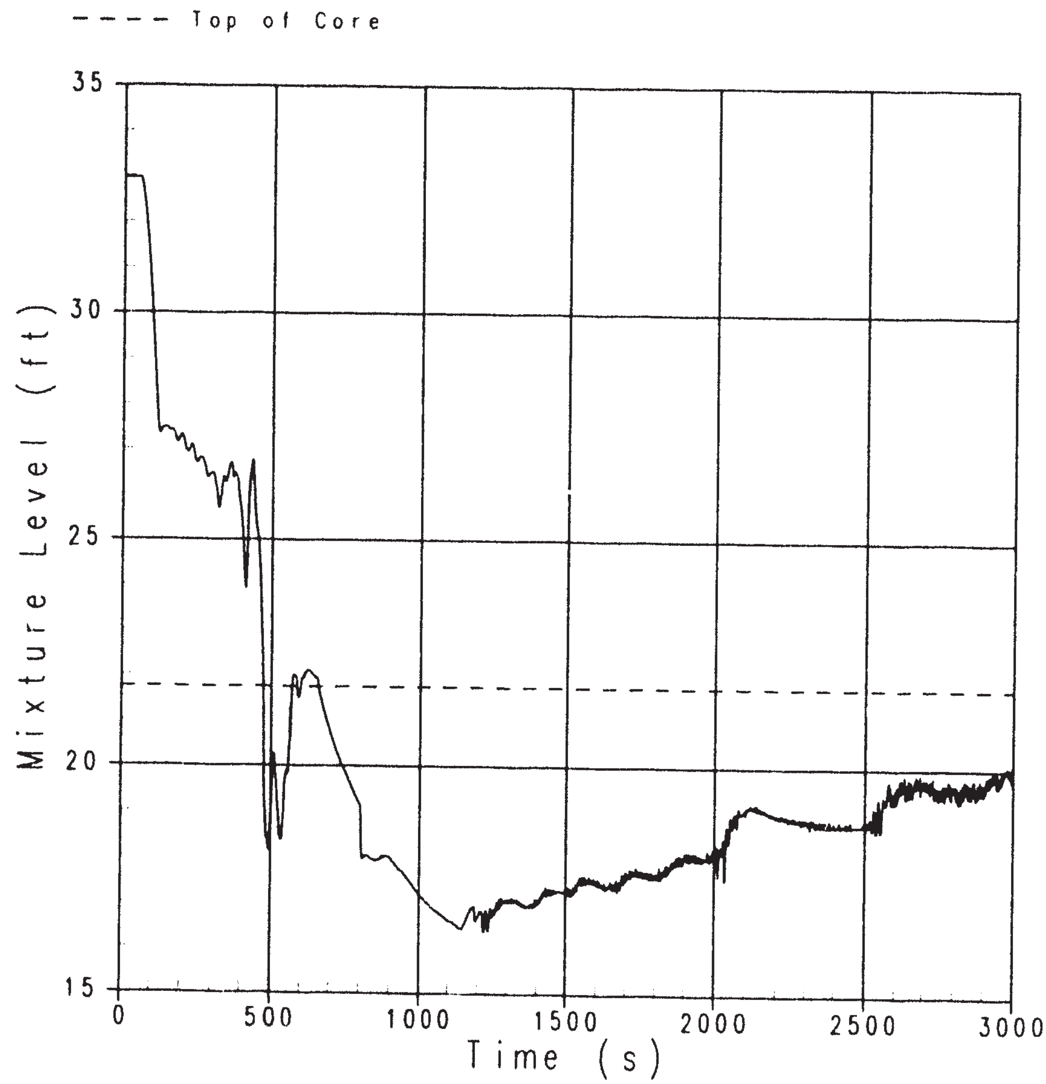


Figure 4.1.2-20
Core Mixture Level, 3-Inch Break, Low T_{avg}, Unit 2

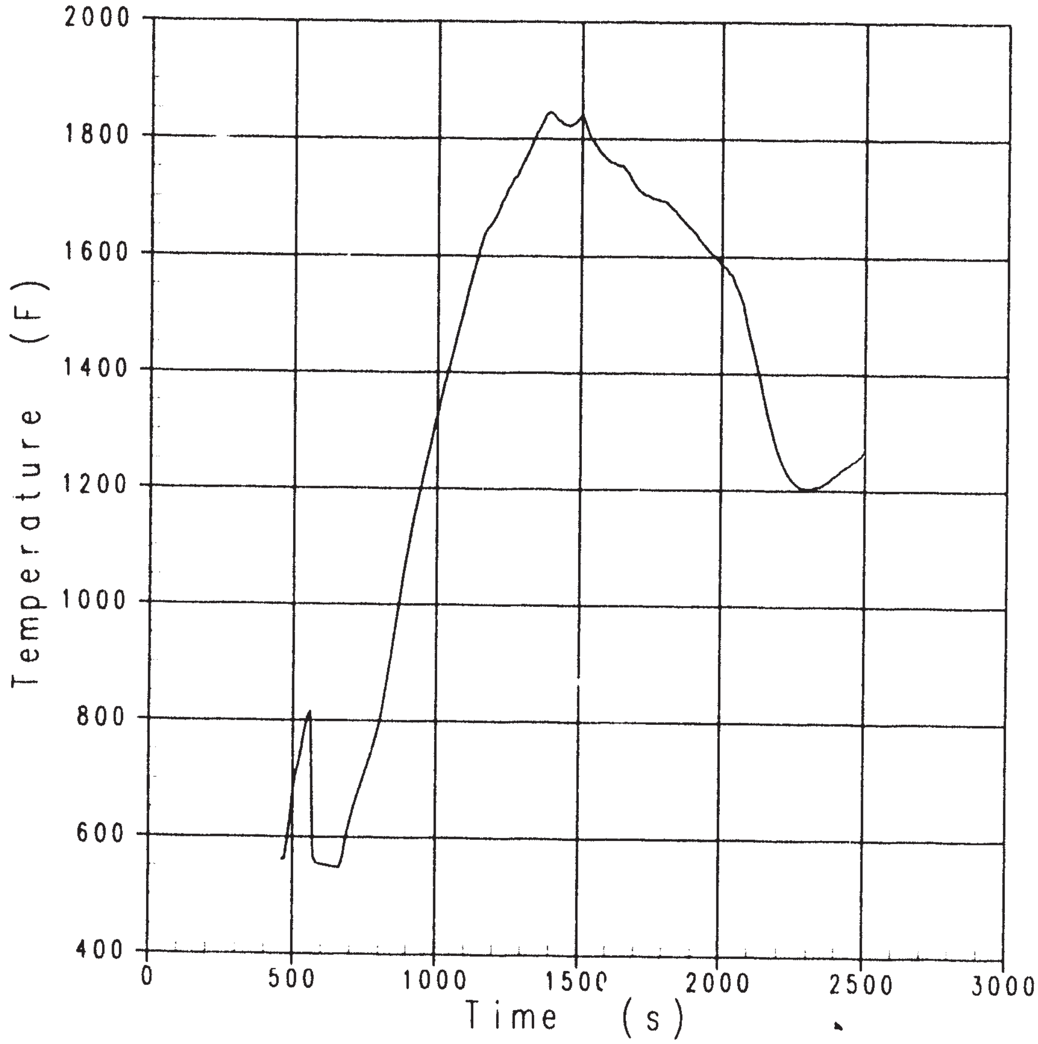


Figure 4.1.2-21
Peak Cladding Temperature - Hot Rod, 3-Inch Break, Low T_{avg}, Unit 2

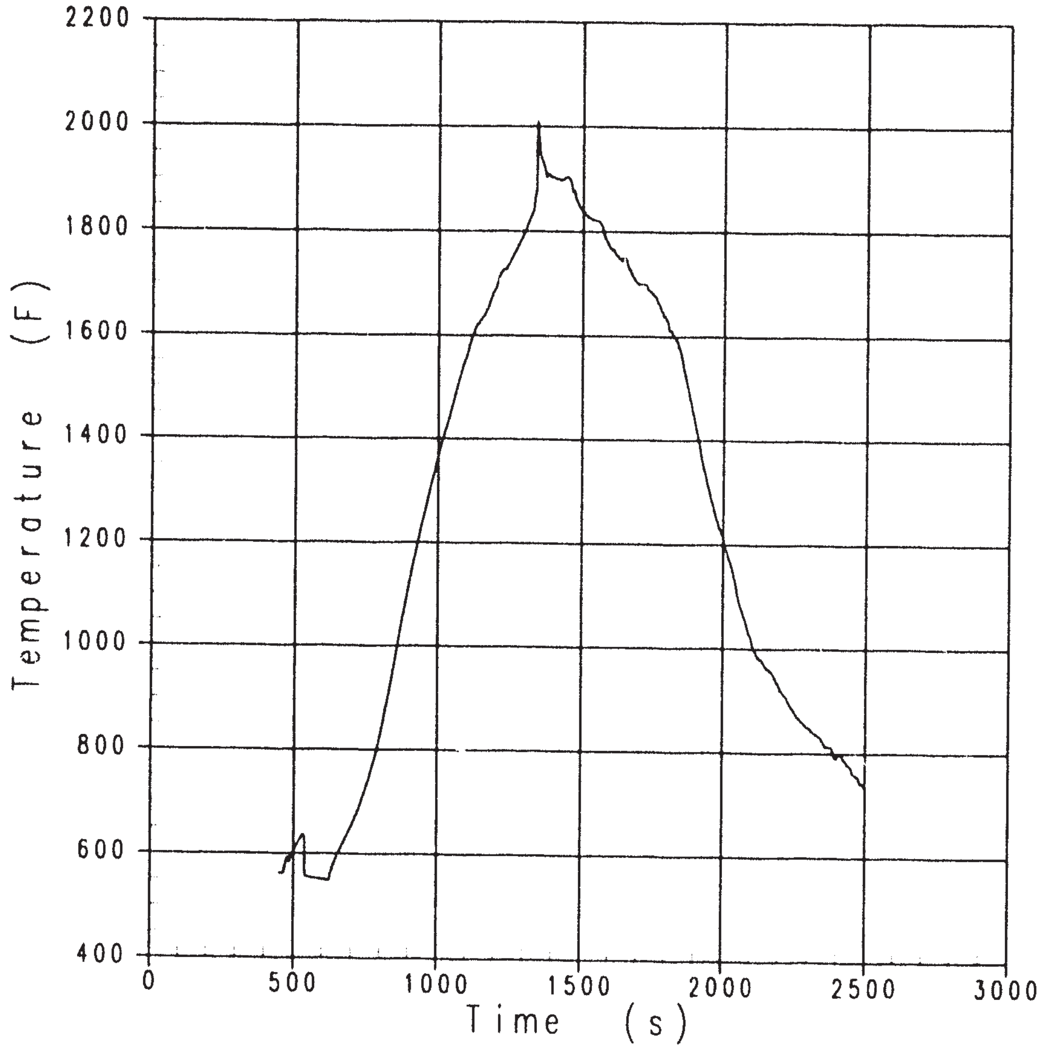


Figure 4.1.2-22
Peak Cladding Temperature - Hot Rod, 3-Inch Break, High T_{avg}, Unit 1, ZIRLO Cladding, 6000 MWD/MTU

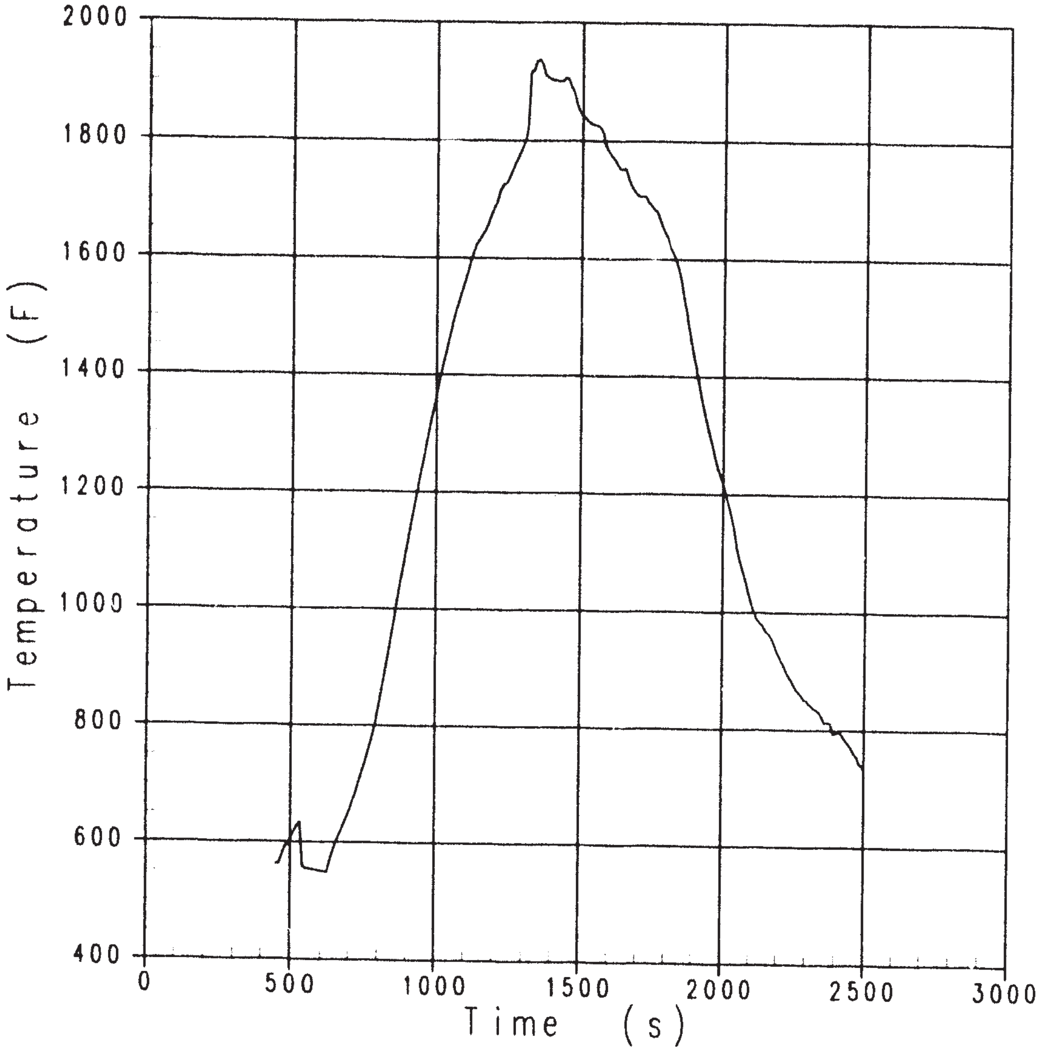


Figure 4.1.2-23
Peak Cladding Temperature - Hot Rod, 3-Inch Break, High T_{avg}, Unit 1, Zirc-4 Cladding, 6000 MWD/MTU

4.2 NON-LOSS OF COOLANT ACCIDENT TRANSIENTS

4.2.0 Introduction

The Final Safety Analysis Report (FSAR) Chapter 15 non-LOCA analyses applicable to the Farley Units 1 and 2 were reviewed to determine their continued acceptability based upon plant operation with the replacement of the Model 51 with the Model 54F steam generators. The analyses and evaluations performed in support of the 54F RSGs continue to include the same basic analysis assumptions included in the Power Uprate Project (Reference 1). Therefore, in most cases the analyses performed for the V5 fuel upgrade (Reference 2), Overtemperature ΔT/Overpower ΔT (OPΔT/OTΔT) setpoint revisions (Reference 3), and Power Uprate Project remain the applicable licensing basis analysis for Farley Units 1 and 2. The FSAR Chapter 15 non-LOCA events which were re-analyzed for RSG conditions are described in this section. The remaining non-LOCA design basis events were determined to be insensitive to or, in the case of the Boron Dilution event in Modes 1 and 2, favorably effected by the Model 54F; thus, qualitative evaluations of those events were performed. Note that the Steamline Break Analyses performed for mass and energy releases are addressed in Section 4.5.

A summary of the key analysis assumptions applicable to the RSG Program is given in Table 4.2.0-1. It should be noted that Table 4.2.0-1 is unchanged from a similar table presented in the licensing report for the Farley Units 1 and 2 Power Uprate Project, with the exception of the initial condition uncertainty on steam generator water level. A comparison of key design and operating parameters for the Model 51 and Model 54F steam generators is given in Tables 2.1-1 and 2.1-2. Section 4.2.0.1 contains a discussion of the basis used to determine whether an analysis or evaluation is required for the non-LOCA events.

Table 2.2-1 lists all of the non-LOCA events. Those events that are bounded by the power uprate analysis are identified as such in the table. The following non-LOCA events were reanalyzed for Farley Units 1 and 2 to support the RSG Program:

- Loss of Normal Feedwater (Section 4.2.1)
- Loss of All ac Power to the Station Auxiliaries (Section 4.2.2)
- Rupture of a Main Steamline at Zero Power (Section 4.2.3)
- Major Rupture of a Main Feedwater Pipe (Section 4.2.4)

The results of all of the analyses and evaluations demonstrate that applicable non-LOCA safety analysis acceptance criteria have been satisfied for Farley Units 1 and 2 with the RSGs.

4.2.0.1 Description of Evaluation

This section describes the basis used to decide which non-LOCA events required reanalysis and which events could be addressed by evaluation. In the analysis of several events, the secondary side is not important to the transient results. This is because the faulted condition occurs on the primary side and the system response occurs too rapidly to be influenced by the secondary side response. Events in this category include rod withdrawal from subcritical, RCCA ejection, partial and complete loss of flow, and locked rotor. Other events are sensitive to core power distribution, and the analysis is decoupled from the steam generator. Events in this category are the RCCA misalignments events. For the remaining events, the key parameters important to the non-LOCA analyses were reviewed to determine if an analysis or evaluation was required.

Tables 2.1-1 and 2.1-2 include changes to the parameters related to the steam generator design and operation that could potentially impact the various non-LOCA events. As previously mentioned, the key NSSS performance parameters on the primary side (power, thermal design flow, minimum measured flow, vessel average temperature range, etc.) are unchanged from the uprate program. Additionally, with the exception of the reduction in initial steam generator water level uncertainty, none of the key analysis assumptions identified in Table 4.2.0-1 (steam generator tube plugging level, fuel related parameters, etc.) change with this program. Therefore, changes are related only to the RSG and the programmed operating level.

4.2.0.1.1 Thermal-Hydraulic Performance

The Model 54F steam generator is designed for similar thermal-hydraulic performance to the Model 51 steam generator. The steam pressure for a given set of operating conditions provides a good indication of the steam generator performance. A review of the secondary-side performance parameters show that although the primary-side conditions are unchanged from the uprate program and assumed steam generator tube plugging levels are the same, due to the uncertainty in the fouling factor of the RSGs, the Model 54F steam generator has a reduced minimum nominal operating pressure and an increased maximum nominal operating pressure. Thus, at nominal operating conditions, the minimum design steam pressure is 656 psia and the maximum design steam pressure 817 psia. The design steam pressure for the Model 51 steam generator for comparable conditions considered in the power uprate is 675 psia to 798 psia. The increase in pressure range at nominal conditions is not the result of a significantly different thermal-hydraulic performance, but due to added conservatism applied to the steam generator heat transfer coefficients.

The non-LOCA evaluation also considered the range of steam pressures by specifically extending the range of conditions that OTΔT setpoint must protect to include the lower pressure. The OTΔT and OPΔT setpoints were confirmed for the extension of the range of protection. Additional details are provided in Section 4.2.0.2.

Other than the OTΔT/OPΔT setpoint calculations, most of the non-LOCA transients are not significantly impacted by changes in the initial steam pressure. Of the licensing basis analyses, only the steamline break event has the potential for a significant change as the result of the higher steam pressure. The steamline break events were reanalyzed as part of the 54F RSG Program using the RETRAN-02 code. The steamline break event analysis is described in detail in Section 4.2.3.

4.2.0.1.2 Secondary-Side Volume, Water Inventory, and Level Setpoints

The Alloy 690 tube material in the Model 54F steam generator has reduced thermal conductivity relative to the Alloy 600 tube material used in the Model 51 steam generator. To compensate, the number of tubes (and heat transfer surface area) is increased. This results in an increase in the primary-side volume and a decrease in the secondary-side volume (in the tube bundle region). The decrease in secondary-side volume, depending on the low-low level setpoint selection, will reduce the water mass available to remove decay heat, sensible heat, RCP heat, etc. during the loss of normal feedwater, loss of offsite power, and feedwater pipe break events. Primarily for this reason, these events were reanalyzed as part of the RSG. These analyses were performed with the RETRAN-02 code. The loss of normal feedwater, loss of offsite power, and feedwater pipe break event analyses are described in Sections 4.2.1, 4.2.2, and 4.2.4, respectively.

The nominal level was increased from 58 percent NRS to 65 percent NRS. Despite the decrease in secondary-side volume, the increase in the nominal level setpoint results in an increase in the water mass at the nominal operating level. Small changes to the nominal operating steam generator mass has little or no affect on most non-LOCA analyses. Secondary-side pipe breaks are affected by changes in the water mass corresponding to the nominal level. The loss of normal feedwater and loss of offsite power events are also moderately sensitive to changes in the initial steam generator inventory.

For steamline break events, the initial water mass can affect the blowdown and, for the core response analyses, the rate and magnitude of the primary-side cool down. For the loss of heat sink events, changes to the initial mass can affect the time it takes to reach the low-low steam generator setpoint.

4.2.0.1.3 Primary-Side Steam Generator ΔP

The Model 54F RSGs have more tubes and a larger primary-side flow area than the Model 51 steam generators. Therefore, the RSGs have a reduced primary-side pressure drop. The decrease in the pressure drop will have no adverse effect on the non-LOCA analyses. Most analyses assume full flow, either thermal design or minimum measured, and the pressure loss associated with the steam generator will have no affect on any event analysis that assumes constant flow. For events in which a pump coastdown occurs or for those that rely on natural circulation, the decreased resistance to flow may provide a minimal benefit.

4.2.0.1.4 Primary-Side Reactor Coolant Volume

The relatively small increase in primary-side volume has no effect on the non-LOCA event analyses. However, the increase in volume provides a direct benefit to the boron dilution analyses in which the steam generator comprises part of the active volume. The active primary-side volume is directly proportional to the amount of time the operator has to terminate a boron dilution flow prior to the loss of shutdown margin. An increased active volume provides a benefit, since this results in an increase in the amount of time available to the operator to terminate the event. Although the boron dilution event did not need to be analyzed for the RSG Program, the boron dilution calculations for Modes 1 and 2 were updated to capture the increased margin. The current licensing-basis analysis for the other modes are unchanged and remain bounding.

4.2.0.1.5 Summary of Required Reanalysis

In summary, based on the key parameter differences between the Model 51 steam generators and the Model 54F RSGs, as discussed above, only the uncontrolled boron dilution (Modes 1 and 2), loss of normal feedwater, loss of all ac power to the station auxiliaries, rupture of a main steamline at zero power, major rupture of a feedwater pipe, and steam system piping failure at full power have been reanalyzed to support the RSGs.

4.2.0.2 Protection System Setpoints

The non-LOCA event analyses performed for the RSG Program use the reactor protection and engineered safety feature systems for event mitigation. The analyses performed for RSG conditions explicitly credit the overpower ΔT, low steamline pressure, and low-low steam generator water level protection system setpoints. Additionally, the range of RCS conditions bounded by the core thermal limits were evaluated to ensure that the existing OTΔT/OPΔT reactor trip setpoints continued to provide protection. Changes were required to the safety analysis limit values for the low pressurizer pressure, the Permissive 8 (P-8) and the low-low steam generator water level (without adverse environment) protection system setpoints. To preserve the overtemperature ΔT setpoint the low pressurizer pressure safety analysis limit setpoint is increased from 1825 psig to 1831 psig. This also led to the change in the P-8 safety analysis value from 40 percent RTP to 38 percent RTP. To obtain acceptable results in the loss of normal feedwater event, the low-low steam generator water level safety analysis limit setpoint is increased from 16 percent NRS to 19 percent NRS. It should be noted that none of these changes to the setpoint safety analysis limit values result in a revision to the protection system setpoints documented in the Technical Specifications.

The protection system setpoints and delay times explicitly credited in the non-LOCA analyses performed to support the RSG Program are summarized in Tables 4.2.0-2 and 4.2.0-3. The total delay time is defined as the time delay from the time the trip conditions are reached to the time the rods are free to fall. Note that no delay time associated with any protection system function has been changed for any analysis or evaluation performed for the RSG Program.

4.2.0.2.1 Overtemperature ΔT and Overpower ΔT Setpoints

The thermal overtemperature trip, in conjunction with the thermal overpower trip and the steam generator safety valves, provides protection against: DNB, exceeding core exit quality limits of the applicable DNB correlation, vessel hot leg boiling for any combination of power temperature, and axial core power distribution for pressures between the low and high pressurizer pressure setpoints. Limitations on the range of protection required by the OTΔT trip to protect this range of core thermal limits are provided by the following:

- OPΔT trip places an upper constraint on the power range (expressed in ΔT)

- High and low pressurizer pressure reactor trips limits the range of primary-side pressures

- Opening the steam generator safety valves limits the maximum RCS vessel average temperature

The revised OTΔT/OPΔT setpoints with implementation of relaxed axial offset control (RAOC) were evaluated with respect to changes in operating conditions related to the RSGs. The increase in the nominal steam pressure range results in a larger range area requiring protection. To preserve the existing OTΔT setpoints the low pressurizer pressure reactor trip safety analysis setpoint is increased from 1825 psig to 1831 psig and the P8 setpoint was reduced to 38 percent RTP. The safety analysis OTΔT/OPΔT setpoint values are unchanged for Farley Units 1 and 2 with the RSG and are specified in Table 4.2.0-2.

4.2.0.3 Non-LOCA Computer Codes

The non-LOCA analyses performed for the Farley Units 1 and 2 RSG Program utilize the RETRAN-02 computer code. Previous analyses of these events used the LOFTRAN computer code. LOFTRAN is approved by the US NRC to perform non-LOCA analyses in Westinghouse PWRs. RETRAN-02 is currently under NRC review for its use in Westinghouse PWRs. A short description of the RETRAN-02 code is provided below.

4.2.0.3.1 RETRAN-02

The RETRAN computer program is used for studies of transient response of a PWR system to specified perturbations in process parameters. RETRAN simulates a multiloop system by a lumped parameter model containing the reactor vessel, hot and cold leg piping, steam generator (tube and shell sides), and the pressurizer. The pressurizer heaters, spray, relief, and safety valves may also be modeled by the program. Point model neutron kinetics and reactivity effects of the moderator, fuel, boron, and control rods are also included.

The secondary side of the steam generator uses a detailed nodalization. The reactor protection system is simulated to include reactor trips on high pressurizer pressure, high pressurizer water level, OTΔT, low-low steam generator water level, etc. Control systems are also simulated including rod control and pressurizer pressure control. Portions of the ECCS (i.e., SI flow), including the accumulators, are also capable of being modeled.

A conservative evaluation of the effect on fuel cladding is performed in RETRAN. Using the RETRAN code, the transient value of departure from nucleate boiling ratio (DNBR), based on the input from the core thermal limits, is calculated. The DNB portion of the core thermal limits defines the locus of conditions where the DNBR value is equal to the safety analysis limit for the appropriate DNB correlation. The DNBR calculation performed is a partial derivative approximation of the DNB core limit lines.

RETRAN does not perform direct calculations of the critical heat flux ratio. Rather, the partial derivative values are applied to the limit value input to RETRAN and are intended to approximate the change in DNBR with respect to the process parameters of power, pressure, and temperature. The nominal DNBR value input is the lesser value calculated at nominal conditions for a typical fuel cell or a thimble fuel cell. Consistent with the Westinghouse licensing approach, the application of the partial derivative values have been shown to yield both a conservative means of confirming that the DNB design basis is met and a reliable indicator of the relative trend of DNBR with time, although this method yields only approximate values of the absolute DNBR.

Note that for DNB events analyzed at or near zero power (e.g., Steamline Break), statepoints are generated and a detailed DNBR analysis is performed to confirm that the DNBR limit is met.

A more detailed description of the RETRAN code model is available in Reference 4. Details of the Westinghouse PWR RETRAN model are provided in Reference 5.

4.2.0.4 References

1. *Farley Nuclear Plant Units 1 and 2 Power Uprate Project NSSS Licensing Report*, WCAP-14723 (Proprietary) and WCAP-14724 (Non-Proprietary), January 1996

2. Letter THFL-91-283, Davidson S. L. to McKinnon, D., *Final Farley Units 1 and 2 VANTAGE 5 Reload Transition Safety Report and Licensing Submittal*, May 20, 1991

3. Letter from USNRC to SNC, *Issuance of Amendments - Joseph M. Farley Nuclear Plant Units 1 and 2 (TAC Nos. M95700 and M95701)*, which responded to SNC letter dated June 12, 1996, *Technical Specification Change Request, Revision to Core Limits and OTΔT & OPΔT Setpoints and Implementation of RAOC*, September 3, 1996

4. C. E. Peterson, et al., *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, EPRI NP-1850-CCM, Rev. 6, December 1995

5. D. S. Huegel, et al., *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, WCAP-14882 (Proprietary), June 1997

Table 4.2.0-1 Non-LOCA Key Accident Analysis Assumptions for Farley Units 1 and 2 RSG Program	
NSSS Thermal Design Flow (per Loop)	86,000 gpm
Minimum Measured Flow (per Loop)	87,800 gpm
Programmed Full Power RCS Average Temperature (per Loop)	577.2°F maximum 567.2°F minimum
Maximum Steam Generator Tube Plugging Level	20% average/peak
Max $F_{\Delta H}$ (V5 Fuel) (LOPAR Fuel)	1.70 1.30
Max F_Q	2.50
DNB Methodology (where applicable)	RTDP
Max End of Life (EOL) Moderator Density Coefficient (MDC)	0.50 Δk/g/cc
Max BOL MTC	+7 pcm/°F ≤70% rated thermal power (RTP) ramping to 0 at 100% RTP
Initial Condition Uncertainties: Power Temperature Pressure Steam Generator Water Level Pressurizer Water Level RCS Flow	 +/- 2% RTP +/- 6°F +/- 50 psi +/- 6% NRS[1] +/- 5% span +/-2.4% TDF

Notes:

(1) Revised assumption from Farley Units 1 and 2 Power Uprate Project. Value accounts for velocity head effects.

Table 4.2.0-2 Safety Analysis Limit Setpoint Values Overtemperature ΔT and Overpower ΔT Setpoints					
OTΔT			**OPΔT**		
$K1_{Analysis}$	=	1.33	$K4_{Analysis}$	=	1.166
K2	=	0.017	K6	=	0.00109
K3	=	0.000825	f(ΔI)	=	0
f(ΔI)	+ wing = 15%, %DI = 2.05%				
	- wing = -23%, %DI = 2.48%				

Table 4.2.0-3 Protection System Setpoints Assumed in Analyses and Evaluation Supporting Farley Units 1 and 2 RSG Program		
Protection Function	**Time Delay (seconds)**	**Maximum Trip Setpoint Assumed for Analysis**
Overtemperature ΔT	12.0[1]	Variable (see above)
Overpower ΔT	12.0[1]	Variable (see above)
Permissive 8	NA	38% RTP
Low Pressurizer Pressure	2.0	1831 psig
Low Steamline Pressure	2.0	429 psig
Low-Low Steam Generator Water Level		
Loss of Normal Feedwater	2.0	19% NRS
Loss of Offsite Power	2.0	16% NRS
Feedwater Pipe Break	2.0	0% NRS

Notes:

(1) Response time modeled in the non-LOCA FSAR Chapter 15 safety analysis as a 10 second lag function followed by a 2 second electronics (pure) delay.

4.2.1 Loss of Normal Feedwater

The loss of normal feedwater event was analyzed for the 54F RSG Program. The analysis used the RETRAN-02 computer code. A detailed description of the analysis is provided in this section.

4.2.1.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite ac power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor is not tripped during this event, core damage would possibly occur as a result of the loss of heat sink while at power. If an alternative supply of feedwater is not supplied to the plant, residual heat following a reactor trip may heat the primary system water to the point where water relief from the pressurizer could occur. A significant loss of water from the RCS could lead to core uncovery and subsequent core damage. However, since a reactor trip occurs well before the steam generator heat transfer capability is reduced, the primary system conditions never approach those that would result in a DNB condition.

The loss of normal feedwater that occurs as a result of the loss of ac power is discussed in Section 4.2.2.

The events listed below occur following the reactor trip for the loss of normal feedwater as a result of main feedwater pump failures or valve malfunctions.

a. As the steam system pressure rises following the trip, the main steam system PORVs are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the steam generator PORVs are not available, the self-actuated main steam safety valves will lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

b. As the no-load temperature is approached, the main steam PORVs (or the self-actuated safety valves, if the PORVs are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

The following provide the necessary protection against core damage in the event of a loss of normal feedwater:

a. Reactor trip on low-low water level in any steam generator

b. Two motor-driven AFW pumps that are started on:

    1. Low-low water level in any steam generator

    2. Any safety injection signal

    3. Loss of offsite power (automatic transfer to diesel generators)

4. Trip of both unit main feedwater pumps

5. Manual actuation

c. One turbine-driven AFW pump that is started on:

1. Low-low water level in any two steam generators

2. Undervoltage on any two of three reactor coolant pump buses

3. Manual actuation

The analysis shows that following a loss of normal feedwater, the AFWS is capable of removing the stored and residual heat thus preventing overpressurization of the RCS, overpressurization of the secondary side, water relief through the pressurizer safeties, and uncovery of the reactor core.

4.2.1.2 Input Parameters and Assumptions

The following assumptions are made in the analysis.

a. The plant is initially operating at 102 percent of the NSSS power (2785 MWt) with all three RCPs in operation providing a constant reactor coolant volumetric flow equal to the thermal design flow value. A conservatively high RCP heat addition of 15 MWt (5 MWt/pump) is assumed. It is assumed that the operator manually trips two of three RCPs 10 minutes after reactor trip (rod motion). At this time, the RCP heat addition is reduced from 15 MWt to 5 MWt.

b. An uncertainty of ± 6°F on the initial reactor vessel average coolant temperature is conservatively assumed to account for the temperature uncertainty on nominal temperature and also includes a -1.0°F bias due to cold leg streaming. The initial pressurizer pressure uncertainty is 50 psi and is conservatively subtracted from the nominal pressure value.

c. Reactor trip occurs on steam generator low-low water level at 19.0 percent of NRS.

d. It is assumed that two motor-driven AFW pumps are available to supply a minimum of 350 gpm to three steam generators, 60 seconds following a low-low steam generator water level signal. The event assumes the worst single failure of one turbine-driven AFW pump. A sensitivity analysis was performed that assumed AFW flow to only two steam generators, and it was determined that the analysis was more limiting if AFW flow is delivered to all three steam generators.

e. The pressurizer sprays and power-operated relief valves (PORVs) are assumed operable. This maximizes the pressurizer water volume. If these control systems did not operate, the pressurizer safety valves would prevent the RCS pressure from exceeding the RCS design pressure limit during this transient.

f. The pressurizer heaters are assumed operable. This includes the proportional and backup heaters. The proportional heaters are fully actuated when the pressurizer pressure decreases by 15 psi from the initial reference pressure (-15 psid). The capacity of the proportional heaters is 0.98 MWt. The backup heaters are actuated on decreasing pressure (-25 psid) or when the pressurizer water level increases by five percent span. The capacity of the backup heaters is 0.42 MWt. The total capacity of the pressurizer heaters is 1.4 MWt. This represents an addition to the RCS energy that must be removed by the AFWS.

g. Secondary system steam relief is achieved through the self-actuated main steam safety valves. Note that steam relief will, in fact, be through the steam generator atmospheric relief valves or condenser dump valves for most cases of loss of normal feedwater. However, since these valves and controls are not safety grade, they have been assumed unavailable.

h. The main steam safety valves are modeled assuming a three percent tolerance and a conservative accumulation model (three percent accumulation for Banks 1, 2, and 3, two percent accumulation for Bank 4, and 10 psi accumulation for Bank 5, respectively, beginning with the valve with the lowest setpoint).

i. Core residual heat generation is based on the 1979 version of ANS 5.1 (Reference 1). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates. Long-term operation at the initial power level preceding the trip is assumed.

j. This analysis bounds steam generator tube plugging levels of 0 percent to 20 percent.

k. The AFWS is actuated by a low-low steam generator water level signal at 19.0 percent of narrow range span. AFW flow begins following a 60-second delay. The AFW line purge volume is conservatively assumed to be the maximum value of 140 ft^3 for either unit and the initial AFW enthalpy is assumed to be 80.83 Btu/lbm.

4.2.1.3 Description of Analysis

A detailed analysis using the RETRAN-02 (Reference 2) computer code is performed to determine the plant transient conditions following a loss of normal feedwater. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs, heaters, sprays, steam generators, main steam safety valves, and the auxiliary feedwater system; and computes pertinent variables, including the pressurizer pressure, pressurizer water level, steam generator level and mass, and reactor coolant average temperature. Details of the Westinghouse PWR RETRAN model are provided in Reference 3.

4.2.1.4 Acceptance Criteria

Based on its frequency of occurrence, the loss of normal feedwater event is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux shall not be exceeded. This is demonstrated by precluding DNB.
- Pressure in the reactor coolant and main steam systems shall be maintained below 110 percent of the design pressures.
- There shall be no propagation to a more serious event.

With respect to DNB and RCS overpressurization, the loss of normal feedwater event is bounded by the loss of external electrical load event.

For ease in interpreting the transient results following a loss of normal feedwater, the following restrictive acceptance criterion is used: the pressurizer shall not become water solid.

4.2.1.5 Results

The calculated sequence of events for this event is listed in Table 4.2.1-1. Figures 4.2.1-1 through 4.2.1-4 present transient plots of the significant plant parameters following a loss of normal feedwater with the assumptions listed in Section 4.2.1.2.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to reduction of the steam generator void fraction and because steam flow through the steam generator safety valves continues to dissipate the stored and generated heat. One minute following the initiation of the low-low level trip, the motor-driven AFW pumps automatically start, consequently reducing the rate at which the steam generator water level is decreasing.

The capacity of the motor-driven AFW pumps enables sufficient heat transfer from the steam generators to dissipate the core residual heat without the pressurizer reaching a water solid condition (as shown in Figure 4.2.1-1). This precludes any water relief through the RCS pressurizer relief or safety valves.

4.2.1.6 Conclusions

With respect to DNB, the loss of normal feedwater event is bounded by the loss of load event, which demonstrates that the minimum DNBR is greater than the safety analysis DNB acceptance criterion. With respect to RCS overpressurization, the loss of normal feedwater event is bounded by the loss of external electrical load event, which demonstrates that the peak primary and secondary system pressures remain below 110 percent of design at all times. The results of the analysis show that the pressurizer does not reach a water solid condition.

Therefore, the loss of normal feedwater event does not adversely affect the core, the RCS, or the MSS.

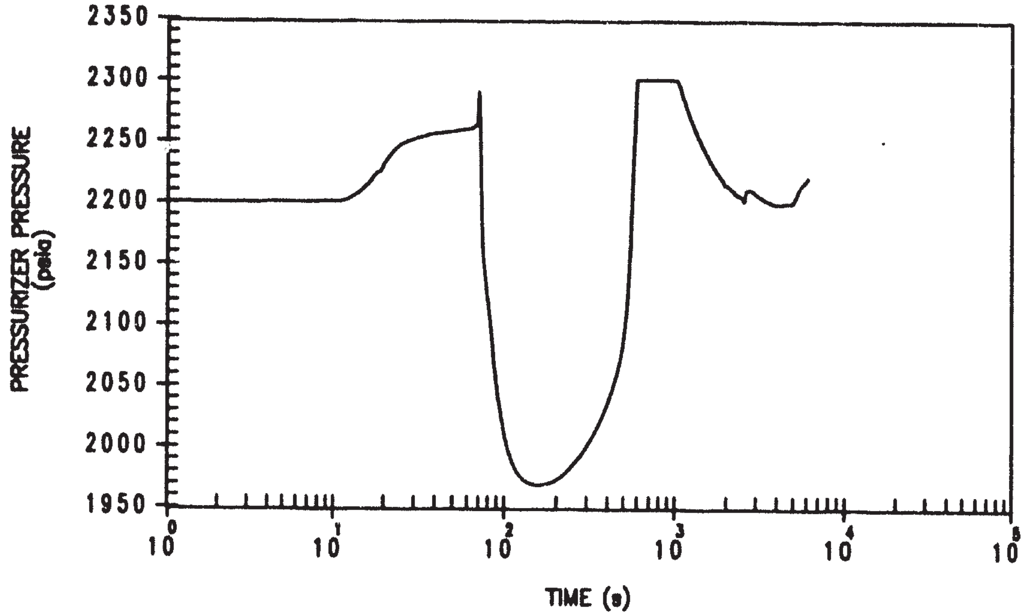
4.2.1.7 References

1. *American National Standard for Decay Heat Power in Light Water Reactors*, ANSI/ANS-5.1 - 1979, August 1979

2. C. E. Peterson, et al., *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, EPRI NP-1850-CCM, Rev. 6, December 1995

3. D. S. Huegel, et al., *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, WCAP-14882 (Proprietary), June 1997

Table 4.2.1-1 Time Sequence of Events for Loss of Normal Feedwater Flow	
Event	**Time (seconds)**
Main Feedwater Flow Stops	10.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	66.0
Rods Begin to Drop	68.0
Flow from Two Motor-Driven AFW Pumps is Initiated	126.0
Operator Action to Trip Two RCPs	668.0
Feedwater Lines are Purged and Cold AFW is Delivered to Three Steam Generators	670.0
Peak Water Level in Pressurizer Occurs	2440.0



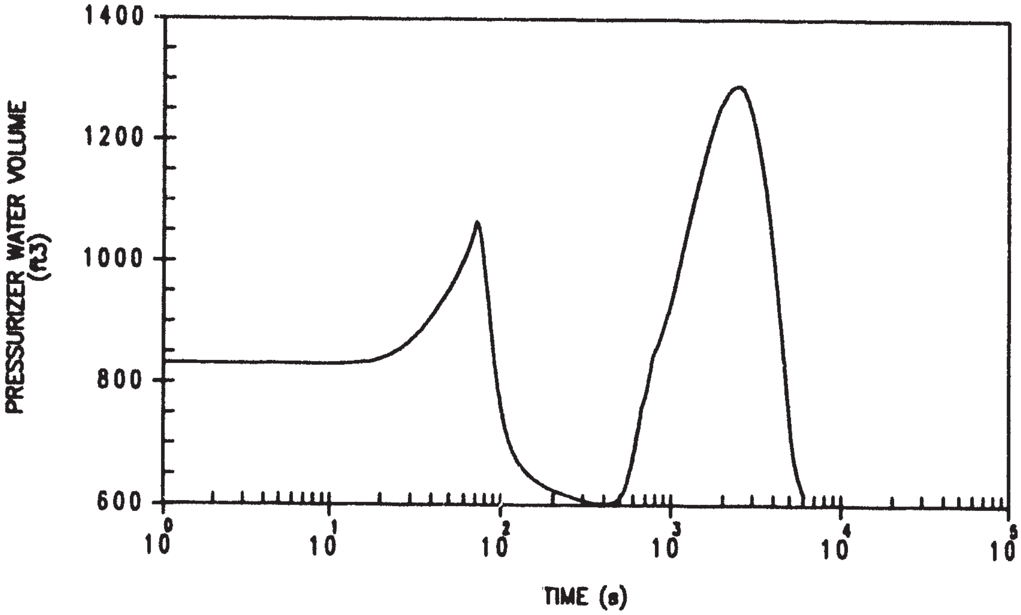


Figure 4.2.1-1
Loss of Normal Feedwater, Pressurizer Pressure and Volume versus Time

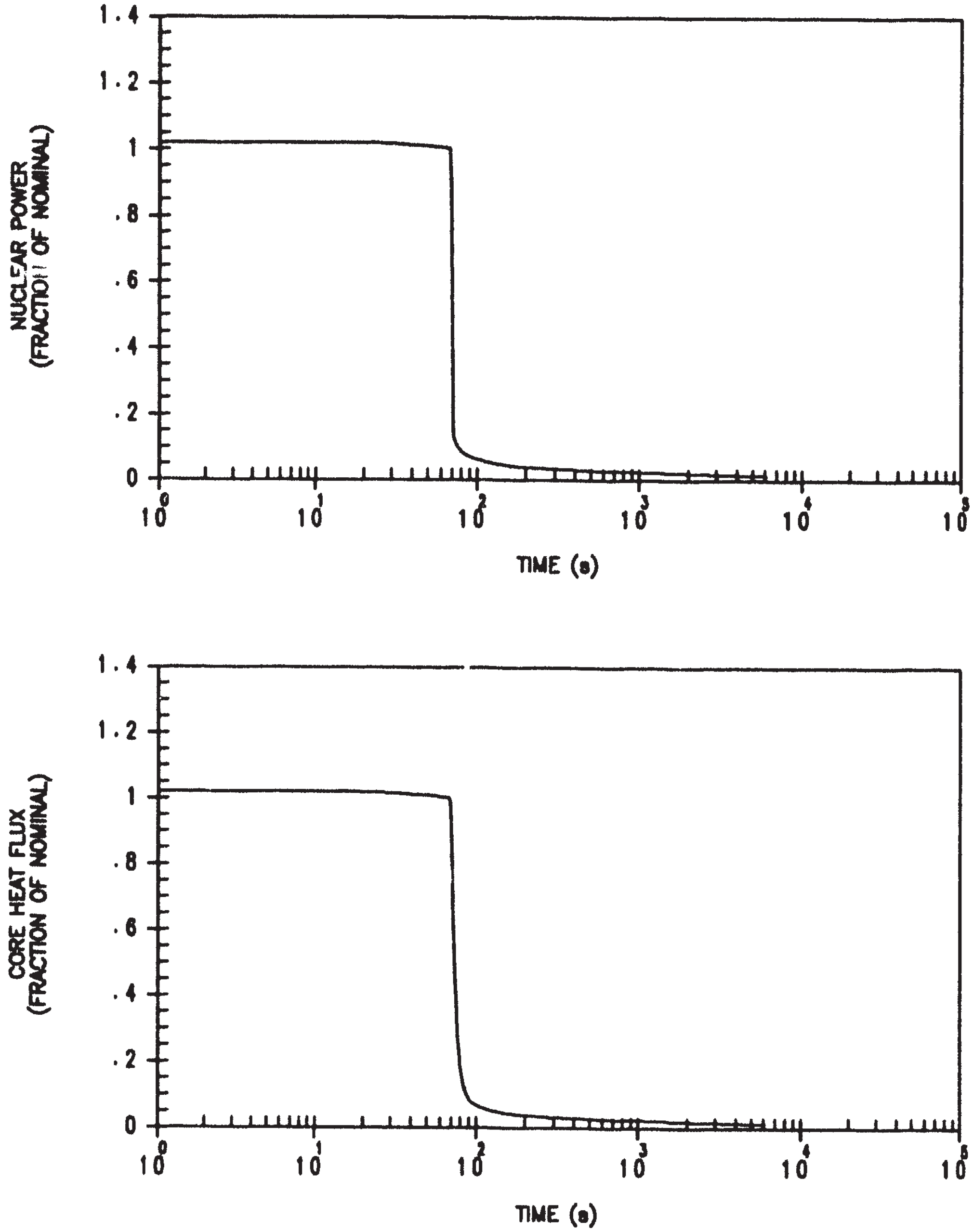


Figure 4.2.1-2
Loss of Normal Feedwater, Nuclear Power and Core Heat Flux versus Time

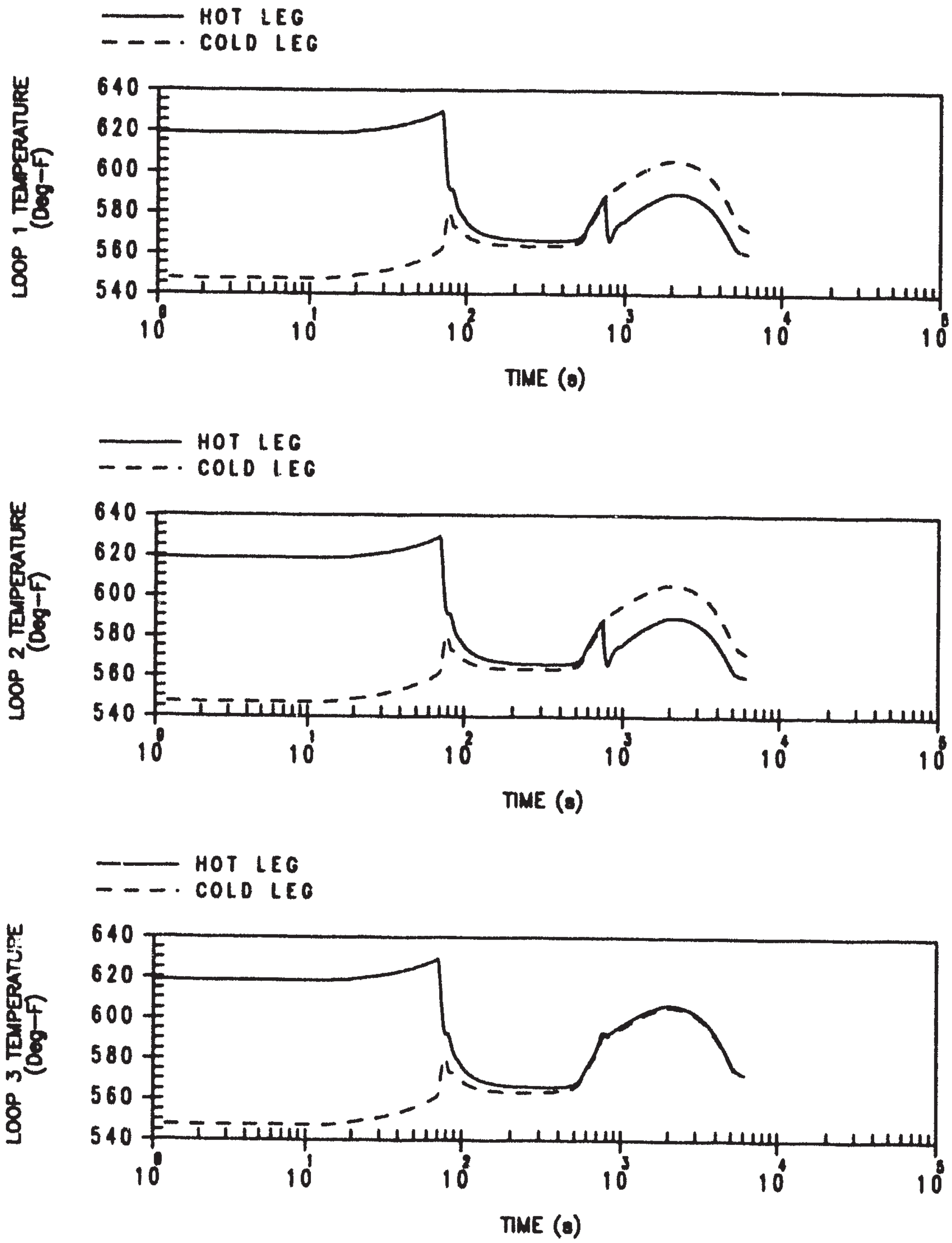


Figure 4.2.1-3
Loss of Normal Feedwater, RCS Loop Temperatures versus Time

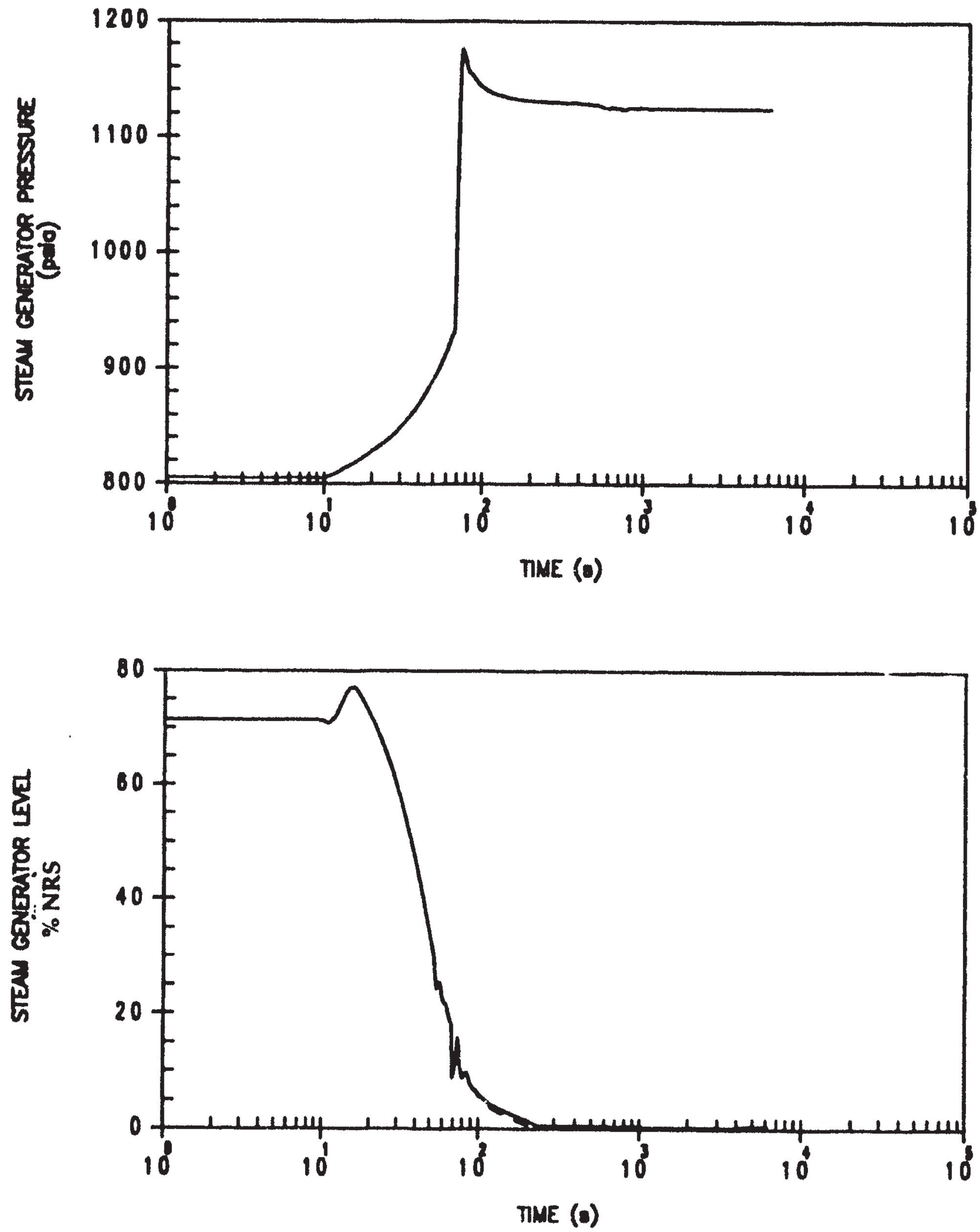


Figure 4.2.1-4
Loss of Normal Feedwater, Steam Generator Pressure and Level versus Time

4.2.2 Loss of All ac Power to the Station Auxiliaries

The loss of all ac power to the station auxiliaries event was analyzed for the 54F RSG Program. The analysis used the RETRAN-02 computer code. A detailed description of the analysis is provided in this section.

4.2.2.1 Identification of Causes and Accident Description

A complete loss of non-emergency ac power will result in a loss of power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip or by a loss of the onsite ac distribution system. The events following a loss of ac power with turbine and reactor trip are described in the sequence listed below.

a. The emergency diesel generators will start on a loss of voltage on the plant emergency buses and begin to supply plant vital loads.

b. Plant vital instruments are supplied by emergency power sources.

c. As the steam system pressure rises following the trip, the main steam system PORVs are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the steam generator PORVs are not available, the self-actuated main steam safety valves will lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

d. As the no-load temperature is approached, the main steam system PORVs (or the self-actuated safety valves, if the PORVs are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

The following provide the necessary protection against a loss of all ac power.

a. Reactor trip on low-low water level in any steam generator

b. Two motor-driven auxiliary feedwater pumps that are started on:

    1. Low-low level in any steam generator
    2. Trip of both main feedwater pumps
    3. Any safety injection signal
    4. Loss of offsite power (automatic transfer to diesel generators)
    5. Manual actuation

c. One turbine-driven auxiliary feedwater pump that is started on:

1. Low-low level in any two steam generators
2. Undervoltage on any two reactor coolant pump buses
3. Manual actuation

The AFWS is initiated as discussed in the loss of normal feedwater analysis (Section 4.2.1). The turbine-driven pump utilizes steam from the secondary side and exhausts it to the atmosphere. The motor-driven AFW pumps are supplied by power from the diesel generators. The AFW pumps are normally aligned to take suction from the condensate storage tank for delivery to the steam generators. A backup source of water for the pumps is provided by the safety-related portion of the service water system (see FSAR Section 4.5). The reactor protection system and AFWS design ensure that reactor trip and AFW flow will occur following any loss of normal feedwater.

Following the loss of power to the RCPs, coolant flow is necessary for core cooling and the removal of residual and decay heat.

Heat removal is maintained by natural circulation in the RCS loops. Following the RCP coastdown, the natural circulation capability of the RCS will remove decay heat from the core, aided by the AFW flow in the secondary side. Demonstrating that acceptable results can be obtained for this event proves that the resultant natural circulation flow in the RCS is adequate to remove decay heat from the core.

The first few seconds after a loss of ac power to the RCPs closely resembles the analysis of the complete loss of forced reactor coolant flow event in that the RCS would experience a rapid flow reduction transient. This aspect of the loss of ac power event is bounded by the analysis performed for the complete loss of flow event which demonstrates that the DNB design basis is met. The analysis of the loss of ac power event demonstrates that RCS natural circulation and the AFWS are capable of removing the stored and residual heat, and consequently will prevent RCS or main steam supply (MSS) overpressurization and core uncovery.

4.2.2.2 Input Parameters and Assumptions

The major assumptions used in this analysis are identical to those used in the loss of normal feedwater analysis (Section 4.2.1) with the following exceptions. Note that the AFWS modeling assumptions, items e and f, are consistent with those used in the loss of normal feedwater.

a. Loss of ac power is assumed to occur at the time of reactor trip on low-low steam generator water level. It is not assumed that the control rods will be immediately inserted as a result of the loss of ac power to the station auxiliaries.

b. Power is assumed to be lost to the RCPs. To maximize the amount of heat addition in the RCS, the power to the RCPs is not assumed to be lost until the start of rod motion.

c. A heat transfer coefficient in the steam generators associated with RCS natural circulation is assumed following the RCP coastdown.

d. The RCS flow coastdown is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, the as-built pump characteristics and conservative estimates of system pressure losses.

e. It is assumed that two motor-driven AFW pumps are available to supply a minimum of 350 gpm to two steam generators, 60 seconds following a low-low steam generator water level signal. (The worst single failure, which is modeled in the analysis, is the loss of the turbine-driven AFW pump.) A sensitivity analysis was performed that assumed AFW flow to all three steam generators and it was determined that the analysis was more limiting if AFW is delivered to only two steam generators.

f. The AFWS is actuated by a low-low steam generator water level signal at 16.0 percent of NRS. AFW flow begins following a 60-second delay. The AFW line purge volume is conservatively assumed to be the maximum value of 140 ft^3 for either unit and the initial AFW enthalpy is assumed to be 80.83 Btu/lbm.

4.2.2.3 Description of Analysis

A detailed analysis using the RETRAN-02 (Reference 1) computer code is performed to determine the plant transient conditions following a loss of all ac power to the station auxiliaries. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs, heaters, sprays, steam generators, main steam safety valves, and the auxiliarv feedwater system. The code computes pertinent variables, including the pressurizer pressure, pressurizer water level, steam generator level and mass, and reactor coolant average temperature. Details of the Westinghouse PWR RETRAN model are provided in Reference 2.

4.2.2.4 Acceptance Criteria

Based on its frequency of occurrence, the loss of all ac power to the station auxiliaries event is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux shall not be exceeded. This is demonstrated by precluding DNB.
- Pressure in the RCS and MSS shall be maintained below 110 percent of the design pressures.
- There shall be no propagation to a more serious event.

With respect to DNB, the loss of all ac power to the station auxiliaries event is bounded by the complete loss of forced reactor coolant flow event. With respect to RCS overpressurization, the loss of all ac power to the station auxiliaries event is bounded by the loss of external electrical load event.

For ease in interpreting the transient results following a loss of all ac power to the station auxiliaries event, the following restrictive acceptance criterion has been used: the pressurizer shall not become water solid.

4.2.2.5 Results

Figures 4.2.2-1 through 4.2.2-4 present transient plots of plant parameters following a loss of non-emergency ac power with the assumptions listed in Section 4.2.2.2. The calculated sequence of events for this event is listed in Table 4.2.2-1.

The first few seconds after the loss of non-emergency ac power to the RCPs, the flow transient for a loss of non-emergency ac power event closely resembles the complete loss of flow incident, where core damage due to rapidly increasing core temperatures is prevented by the reactor trip, which, for a loss of non-emergency ac power event, is on a low-low steam generator water level signal. After the reactor trip, stored and residual heat must be removed to prevent damage to the core and the RCS and MSS. The RETRAN-02 code results show that the natural circulation and AFW flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

Figure 4.2.2-1 illustrates that the pressurizer never reaches a water solid condition. Hence, no water relief from the pressurizer occurs.

4.2.2.6 Conclusions

With respect to DNB, the loss of all ac power to the station auxiliaries event is bounded by the complete loss of flow event, which demonstrates that the minimum DNBR is greater than the safety analysis DNB acceptance criterion. With respect to RCS overpressurization, the loss of all ac power to the station auxiliaries event is bounded by the loss of external electrical load event, which demonstrates that the peak primary and secondary system pressures remain below 110 percent of design at all times. The results of the analysis show that pressurizer does not reach a water solid condition. Therefore, the loss of offsite power event does not adversely affect the core, the RCS, or the MSS.

4.2.2.7 References

1. C. E. Peterson, et al., *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, EPRI NP-1850-CCM, Rev. 6, December 1995

2. D. S. Huegel, et al., *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, WCAP-14882 (Proprietary), June 1997

Table 4.2.2-1
Time Sequence of Events for Loss of All ac Power to the Station Auxiliaries

Event	Time (seconds)
Main Feedwater Flow Stops	10.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	70.2
Rods Begin to Drop	72.2
Reactor Coolant Pumps Begin to Coastdown	74.2
Flow from Two Motor-Driven AFW Pumps is Initiated	130.2
Feedwater Lines are Purged and Cold AFW is Delivered to Two Steam Generators	495.0
Peak Water Level in Pressurizer Occurs (Post Reactor Trip)	1555.0

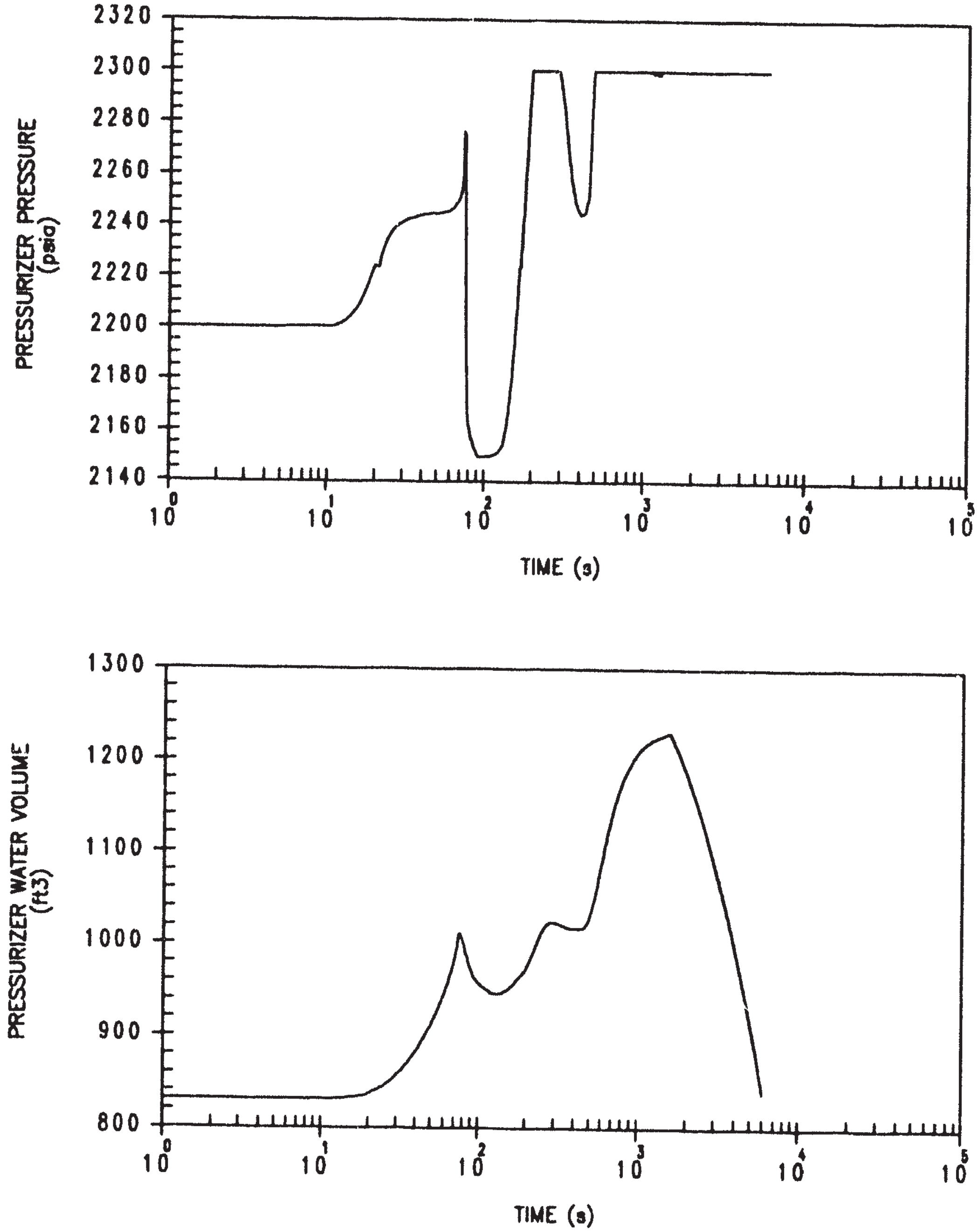


Figure 4.2.2-1
Loss of All ac Power to the Station Auxiliaries, Pressurizer Pressure and Volume versus Time

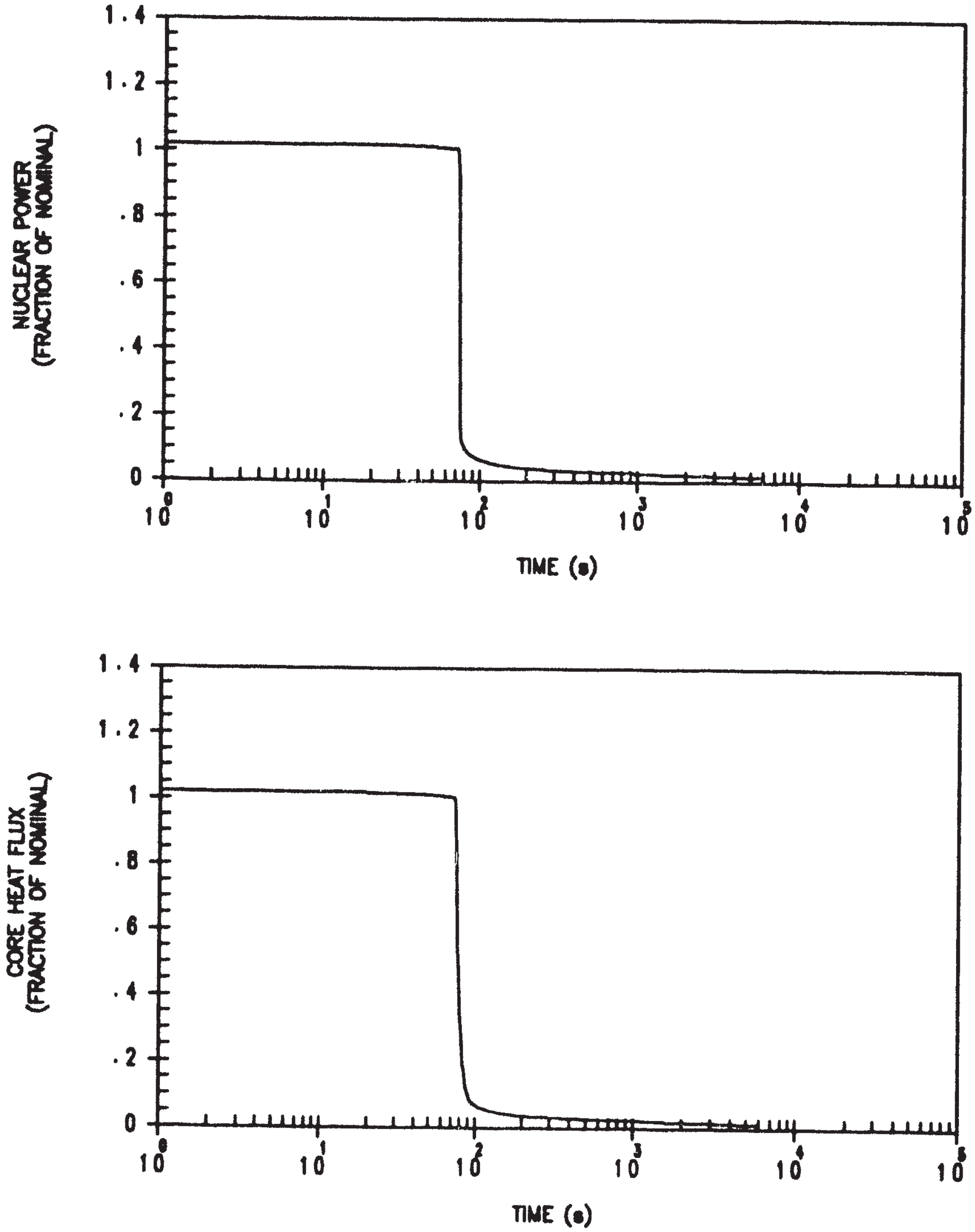


Figure 4.2.2-2
Loss of All ac Power to the Station Auxiliaries, Nuclear Power and Core Heat Flux versus Time

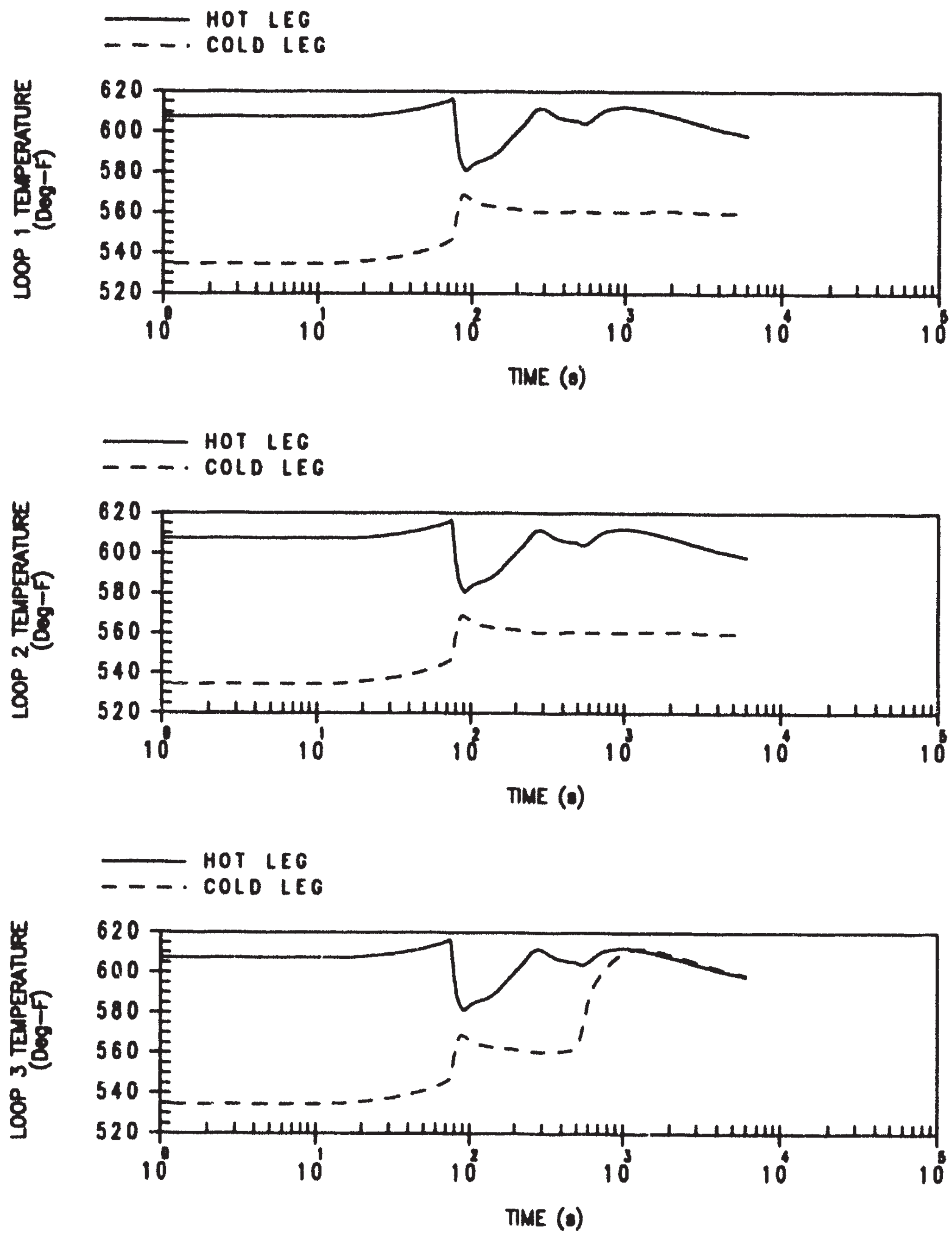


Figure 4.2.2-3
Loss of All ac Power to the Station Auxiliaries, RCS Loop Temperatures versus Time

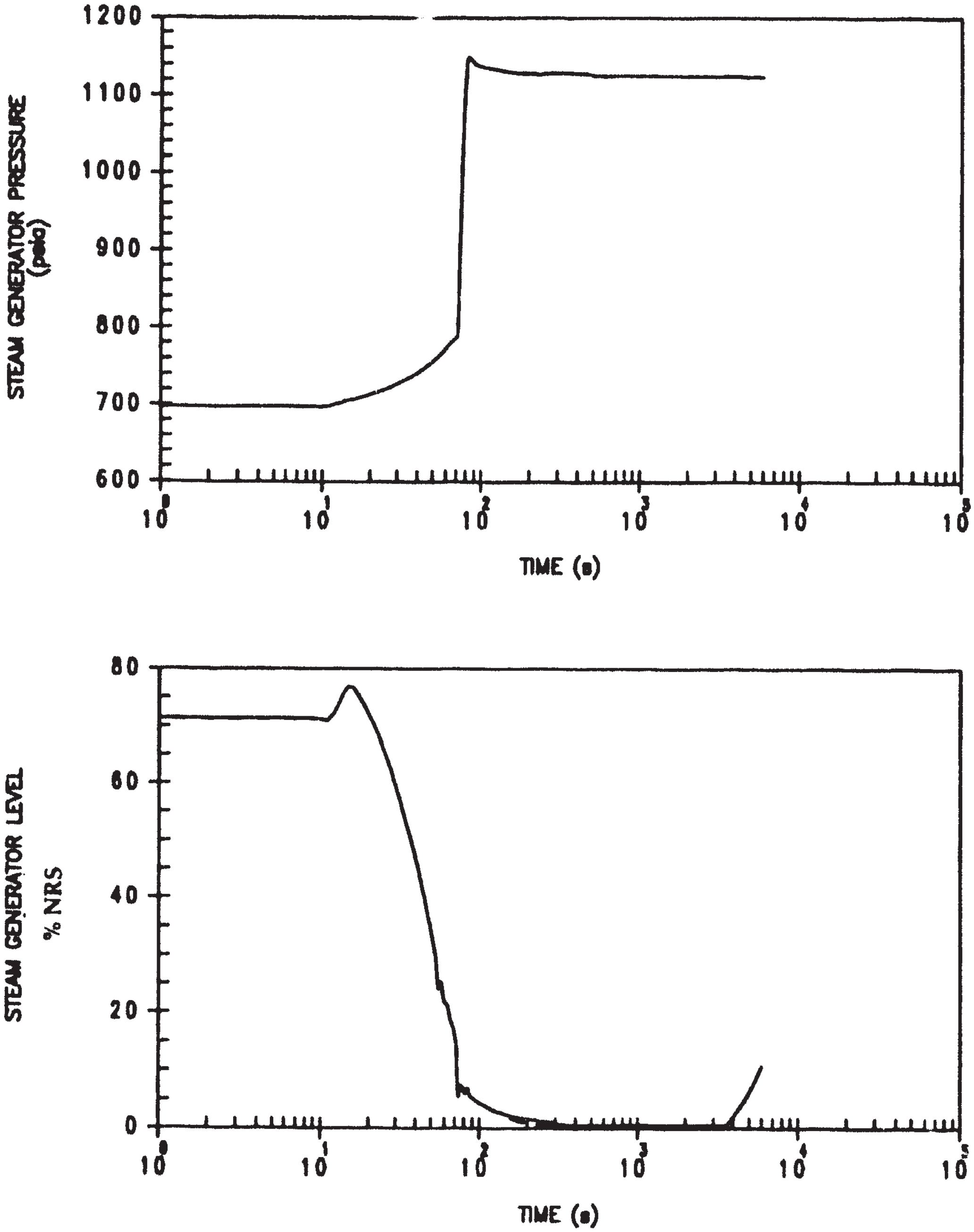


Figure 4.2.2-4
Loss of All ac Power to the Station Auxiliaries, Steam Generator Pressure and Level versus Time

4.2.3 Rupture of a Main Steamline at Zero Power

The rupture of a main steamline at zero power event was analyzed for the 54F RSG Program using the RETRAN-02 computer code. A detailed description of the analysis is provided in this section.

4.2.3.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steamline will result in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a positive reactivity insertion and subsequent reduction in core shutdown margin. If the most-reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential problem, mainly because of the high power peaking factors that would exist assuming the most-reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by boric acid injection delivered by the ECCS and accumulators.

The rupture of a major steamline is the most-limiting cooldown transient. It is analyzed at zero power with no decay heat since decay heat would retard the cooldown, thus reducing the return to power. A detailed discussion of this transient with the most-limiting break size (a double-ended rupture) is presented below.

The following functions provide the necessary protection against a steam pipe rupture:

a. SIS actuation from any of the following:

   1. Two-out-of-three low pressurizer pressure signals
   2. High steamline differential pressure
   3. Low main steamline pressure in two-out-of-three steamlines
   4. Two-out-of-three high-1 containment pressure signals

b. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the SI signal.

c. Redundant isolation of the main feedwater lines to prevent sustained high feedwater flow which would cause additional cooldown. Therefore, a SI signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and indirectly close the feedwater isolation valves that backup the control valves. In addition, trip of the main feedwater pumps results in automatic closure of the respective pump discharge isolation valve.

d. Trip of the fast-acting main steam isolation valves (MSIVs) (assumed to close in 10 seconds stroke time) and main steam isolation bypass values (MSIBVs) (assumed to close in 10 seconds stroke time) after receipt of an ECCS or main steamline isolation signal on:

   1. High steam flow in two-out-of-three main steamlines (one-of-two per line) coincident with two-out-of-three low-low T_{avg} signals
   2. Low steamline pressure signal on two-out-of-three steamlines
   3. Two-out-of-three high-high (High-2) containment pressure signals

For breaks downstream of the isolation valves, closure of all valves will completely terminate the blowdown. For any break, in any location, no more that one steam generator would experience an uncontrolled blowdown even if one of the isolation valves fails to close. Circuit design assures that the MSIBVs are automatically closed whenever the MSIVs are automatically closed.

Following a steamline break, only one steam generator can blowdown completely. Each main steamline is provided with two isolation valves located outside of the containment immediately downstream of the steamline safety valves. The isolation valves are signal-actuated valves that close to prevent flow in the normal (forward) flow direction. The valves on all three steamlines will be driven closed to isolate the respective steam generators. Thus, only one steam generator can blowdown, minimizing the potential steam release and resultant RCS cooldown. In addition, the remaining two steam generators will still be available for dissipation of any decay heat after the initial transient is over. In the case of loss of offsite power, this heat is removed to the atmosphere via the atmospheric relief valves, which have been sized to handle this situation.

Steam flow is measured by monitoring the pressure difference between pressure taps located on the steam generator drum and downstream of the integral flow restrictor nozzles. The effective throat diameter of the flow restrictor nozzles of 14 inches is considerably smaller than the diameter of the main steam pipe. These restrictors are located in the steam generators outlet nozzle and serve to limit the maximum steam flow for any break at any location.

4.2.3.2 Input Parameters and Assumptions

The following conditions were assumed to exist at the time of a main steamline break accident:

a. EOL shutdown margin at no-load, equilibrium xenon conditions, and the most-reactive assembly stuck in its fully withdrawn position. Operation of the control rod banks during core burnup is restricted in such a way, i.e., technical specification rod insertion limits, that addition of positive reactivity in a steamline break accident will not lead to a more adverse condition than the case analyzed.

b. The negative moderator coefficient corresponding to the EOL rodded core with the most-reactive rod in the fully withdrawn position. The coefficient assumption was revised for the RSG analysis to improve the core physics prediction of the point kinetics core model. The variation of the coefficient with temperature and pressure has been included. The k_{eff} versus coolant average temperature at 1000 psia corresponding to the negative moderator temperature coefficient (MTC) plus the Doppler temperature effect used is shown in FSAR, Figure 15.2-40, along with the effect of power generated in the core on overall reactivity. All reactivity physics parameters are weighted toward the core sector exposed to the greatest cool down from the faulted loop.

c. Minimum capability for injection of high concentration boric acid solution corresponding to the most-restrictive single failure in the ECCS. The 2300 PPM boron solution corresponds to the minimum boron concentration in the RWST. No credit has been taken for the low concentration of boric acid that must be swept from the ECCS lines downstream of the RWST isolation valves prior to the delivery of the concentrated boric acid from the RWST to the reactor coolant loops.

The SI flow corresponds to that delivered by one charging/SI pump delivering full flow to the cold leg header. The modeling of the ECCS in the Westinghouse PWR RETRAN model is described in Reference 1.

The boric acid solution from the ECCS is assumed to be uniformly delivered to the three reactor coolant loops. The boron in the loops is then delivered to the inlet plenum where the coolant (and boron) from each loop is mixed and delivered to the core. The calculation assumes the boric acid is mixed with and diluted by the water flowing in the RCS prior to entering the core. The concentration after mixing depends on the relative flowrates of the RCS and the ECCS. The stuck RCCA is assumed to be conservatively located in the core sector near the faulted steam generator.

For the case where offsite power is assumed, the sequence of events in the ECCS is the following. After the generation of the SI signal (appropriate delays for instrumentation, logic, and signal (processing included), the appropriate valves begin to operate and the charging/SI pump starts. In 27 seconds, the valves are assumed to be in the final position and the pump is assumed to be at full speed and to be drawing suction from the RWST. The 27 seconds includes 2 seconds for electronic delay, 10 seconds for the RWST valve(s) to open, and 15 seconds for the volume control tank (VCT) valve(s) to close. (The charging/SI pump(s) start, normal charging isolation, and high-head injection header alignment occur in conjunction with the RWST valve alignment.)

In cases where offsite power is not available, an additional 15-second delay is assumed to start the diesels and to re-energize the engineered safety features (ESF) electrical buses. That is, after a total of 42 seconds following the time a SI setpoint is reached at the sensor, the ECCS is assumed to be capable of delivering flow to the RCS.

The SIS piping contains low concentration (0 PPM assumed) borated water which delays the injection of the 2300 PPM borated RWST water from reaching the RCS. This delay in 2300 PPM boron solution reaching the RCS is inherently included in the RETRAN modeling.

d. To maximize the primary-to-secondary heat transfer rate, 0 percent steam generator tube plugging is assumed.

e. Since the steam generators are provided with integral flow restrictors with a 1.069 ft^2 throat area, any rupture with a break greater than 1.069 ft^2, regardless of the location, would have the same effect on the NSSS as the 1.069 ft^2 break. The following two cases have been considered in determining the core power and RCS transients.

   1. Complete severance of a pipe, with the plant initially at no-load conditions, and full reactor coolant flow (Thermal Design Flow) with offsite power available

   2. Complete severance of a pipe with the plant initially at no-load conditions with offsite power unavailable; loss of offsite power results in reactor coolant pump coastdown

f. Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at EOL. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return-to-power phase following the steamline break. This void, in conjunction with the large negative moderator coefficient, partially offsets the effect of the stuck assembly. The power peaking factors depend on the core power, operating history, temperature, pressure, and flow, and thus are different for each case studied.

   Both cases assume initial hot-standby conditions at event initiation since this represents the most-conservative initial condition. Should the reactor be just critical or operating at power at the time of a steamline break, the reactor will be tripped by the normal overpower protection when the power level (high flux) or ΔT reaches a trip setpoint. Following a trip at power, the RCS contains more stored energy than at no-load, the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steamline break before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis which assumes no-load condition at time zero. In addition, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steamline breaks occurring at power.

g. In computing the steam flow during a steamline break, the Moody Curve (Reference 2) for $f(L/D) = 0$ is used. The Moody multiplier is 1 with a discharge at dry saturated steam conditions.

h. Perfect moisture separation in the steam generator is assumed unless the mixture level reaches the top of the steam generator. The assumption leads to conservative results since, in fact, considerable water would be discharged. Water entrainment would reduce the magnitude of the temperature decrease in the core.

i. The maximum feedwater flow is assumed. Increasing the feedwater flowrate further increases the cooldown in accidents such as steamline rupture. All main and auxiliary feedwater pumps are assumed to be operating at full capacity when the rupture occurs. Main feedwater is isolated following the SI signal; however, auxiliary feedwater continues for the duration of the transient.

j. The effect of heat transferred from thick metal in the pressurizer and reactor vessel upper head is not included in the cases analyzed. The heat transferred from these sources is a net benefit in DNBR and RCS energy when the effect of the extra heat on reactivity and peak power is considered.

4.2.3.3 Description of Analysis

A detailed analysis using the RETRAN-02 (Reference 3) computer code is performed to determine the plant transient conditions following a main steamline break. The code models the core neutron kinetics, RCS, pressurizer, steam generators, SI system and the auxiliary feedwater system. The code computes pertinent variables, including the core heat flux, RCS temperature and pressure. A conservative selection of those conditions are then used to develop core models which provide input to the detailed thermal and hydraulic digital computer code, THINC-IV, to determine if DNB occurs. Details of the Westinghouse PWR RETRAN model are documented in Reference 1.

4.2.3.4 Acceptance Criteria

A major break in a pipeline is classified as an ANS Condition IV event. Minor secondary system pipe breaks are classified as ANS Condition III events. All of these events are analyzed to meet Condition II criteria. The only criterion that may be challenged during this event is the one that states that the critical heat flux should not be exceeded. The evaluation shows that this criterion is met by ensuring that the minimum DNBR does not go below the limit value at any time during the transient.

4.2.3.5 Results

The time sequence of events for postulated steamline rupture accidents with and without offsite power are presented in Table 4.2.3-1. The results presented are a conservative indication of the events that would occur assuming a steamline rupture since it is postulated that all of the conditions described in the prior section occur simultaneously.

Figures 4.2.3-1 through 4.2.3-6 show the RCS transients and core heat flux following a main steam pipe rupture. Offsite power is assumed to be available such that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator.

As can be seen, the core attains criticality with RCCAs inserted (with the design minimum shutdown margin and assuming one stuck RCCA), but is quickly returned to a subcritical condition as a boric acid solution at 2300 PPM (from the RWST) enters the RCS. The delay time consists of the time to receive and actuate the SI signal, to start the charging/safety injection (CHG/SI) pumps, and to completely align valve trains in the ECCS lines, including VCT isolation. The CHG/SI pumps are then ready to deliver flow. At this stage, a further delay is incurred before 2300 PPM boron solution can be injected to the RCS due to the low concentration solution being swept from the SI lines. Should a partial loss of offsite power occur such that power is lost to the ESF functions, an additional SI delay of 15 seconds would occur while the diesel generators start up and re-energize the ESF buses. Allowing for these delays, a peak core power well below the nominal full-power value is attained.

Should the core be critical at near zero power when the rupture occurs, the initiation of the SI signal by high steamline differential pressure, low steamline pressure, or high containment pressure will trip the reactor. Steam release from more than one steam generator will be prevented by automatic closure of the isolation valves in the steamlines by low steamline pressure, a high steam flow signal in coincidence with low-low RCS average temperature, or high-high containment pressure. The MSIVs and MSIBVs are assumed to be fully closed in 10 seconds (stroke time) after receipt of a closure signal. This analysis conservatively assumed 2 seconds to account for signal processing.

Figures 4.2.3-7 through 4.2.3-12 show the responses of the salient parameters for the case discussed above with a total loss of offsite power. This assumption results in a coastdown of the reactor coolant pumps. In this case, the core power increases at a slower rate and reaches a lower peak value than in the cases in which offsite power is available to the reactor coolant pumps. The ability of the emptying steam generator to extract heat from the RCS is reduced by the decreased flow in the RCS.

It should be noted that following a steamline break, only one steam generator blows down completely. Thus, the remaining steam generators are still available for dissipation of decay heat after the initial transient is over. In case of a loss of offsite power, this heat is removed to the atmosphere via the steamline safety valves.

Following blowdown of the faulted steam generator, the plant can be brought to a stabilized hot-standby condition through control of the AFW flow and SI flow, as described by plant operating procedures. The operating procedures call for operator action to limit RCS pressure and pressurizer level by terminating SI flow and to control steam generator level and RCS coolant temperature using the AFWS. Any action required of the operator to maintain the plant in a stabilized condition will be in a time frame in excess of 10 minutes following safety injection.

4.2.3.6 Conclusions

A DNB analysis was performed for the steamline break cases described above. The analysis demonstrated that the minimum DNBR remains above the limit value and thus, concludes that the DNB design basis is met for the steamline break event initiated from zero power with the Model 54F steam generators.

4.2.3.7 References

1. Huegel, D. S., et al., *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, WCAP-14882 (Proprietary), June 1997

2. Moody, F. S., *Transactions of the ASME*, Journal of Heat Transfer, Page 134, February 1965

3. C. E. Peterson, et al., *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, EPRI NP-1850-CCM, Rev. 6, December 1995

Table 4.2.3-1 Time Sequence of Events for Rupture of a Main Steamline	
Event	**Time (Sec)**
With Offsite Power:	
Steamline Ruptures	0.0
Low Steamline Pressure Setpoint Reached in Two Loops	0.9(1)
Steamline Isolation Occurs	14.9(4)
SI Begins	28.0
Borated Water from the RWST Reaches the Core	50.4
Criticality Attained	82.2
Accumulators Actuate	133.1
Peak Core Heat Flux Occurs (Minimum DNBR)	296.4
Without Offsite Power:	
Steamline Ruptures	0.0
Low Steamline Pressure Setpoint Reached in Two Loops	0.9(1)
SI Signal Generated	2.9
Loss of ac Power and RCPs Begin Coastdown	3.0
Steamline Isolation Occurs	14.9(2,4)
SI Begins	43.0
Borated Water from the RWST Reaches the Core	72.3
Criticality Attained	138.3
Peak Core Heat Flux Occurs(3)	335.4

Notes:

(1) This does not include the 2-second instrumentation delay for the low steam pressure SI actuation response time.

(2) Time of main steamline isolation. The MSIBVs close following diesel generator start. The additional blowdown through the main steamline isolation valve bypass lines does not impact the limiting transient results.

(3) Case without offsite power available is not the limiting event.

(4) Analysis includes an extra 2-second delay.

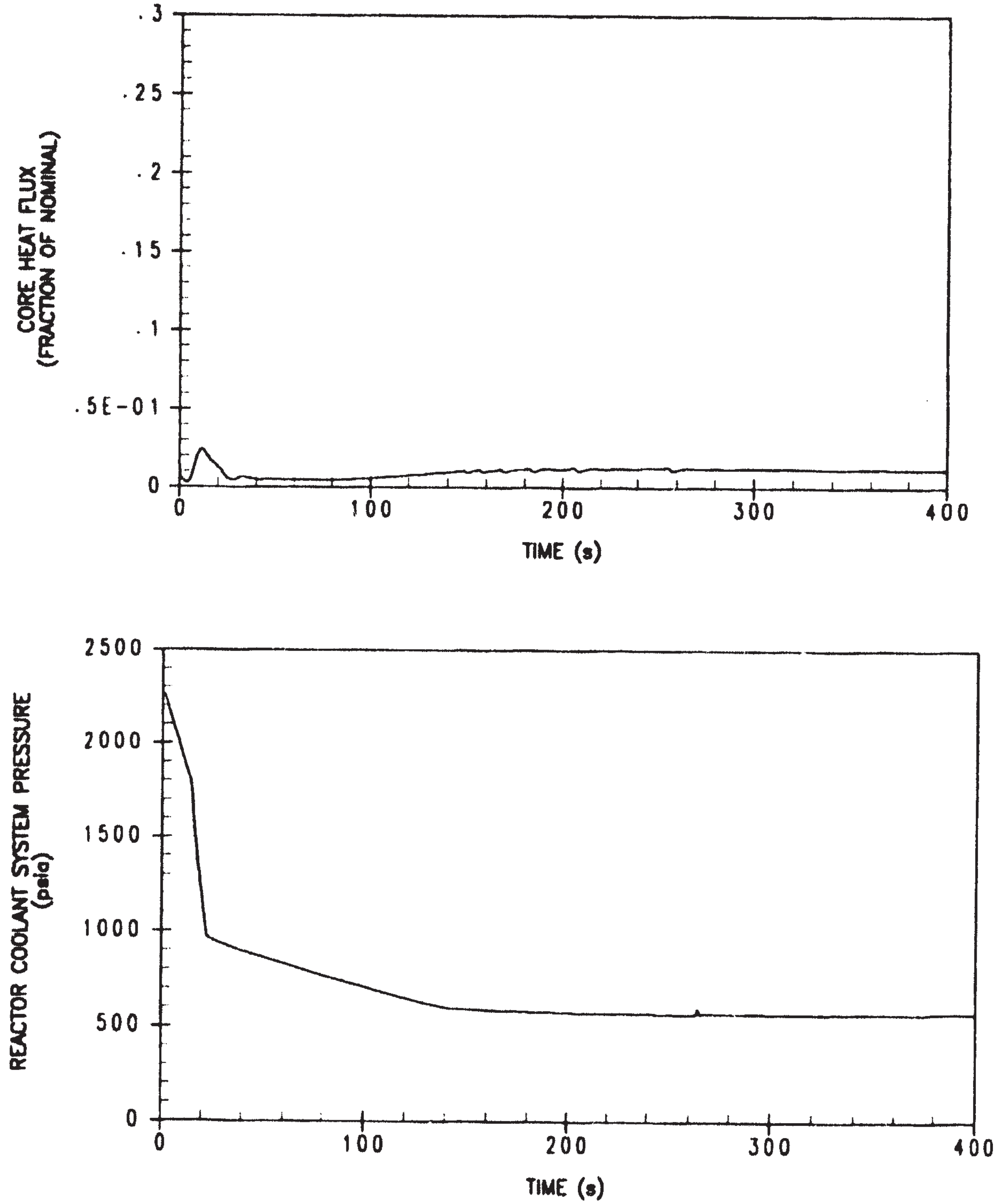
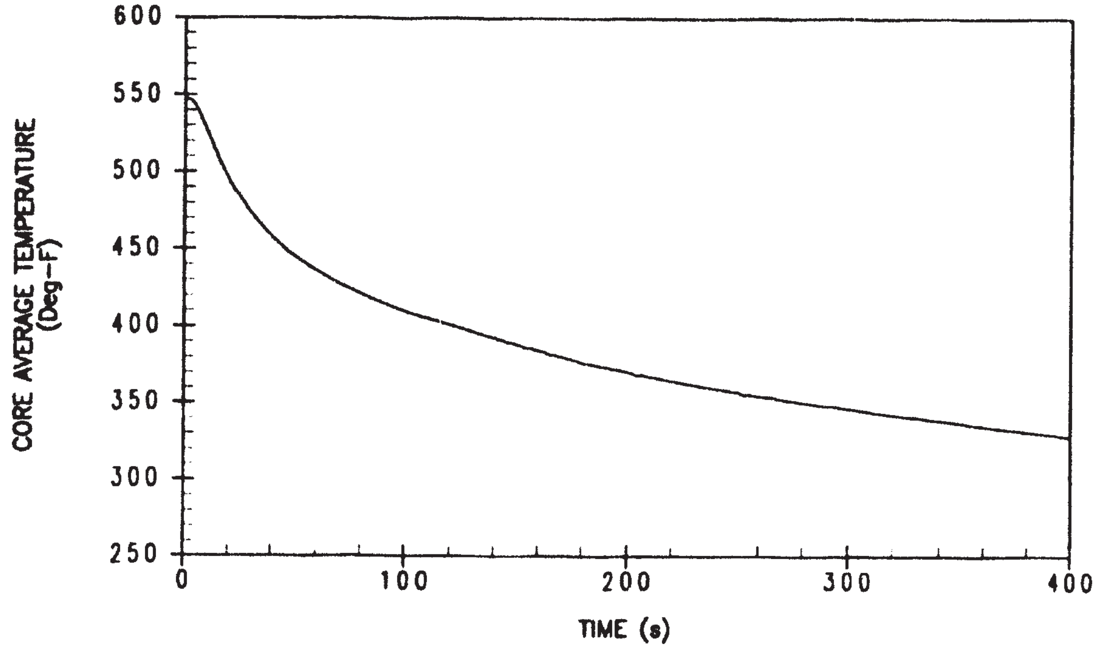


Figure 4.2.3-1
Steamline Break Transient with Offsite Power 1.069 ft² Double-Ended Rupture
Core Heat Flux and RCS Pressure versus Time



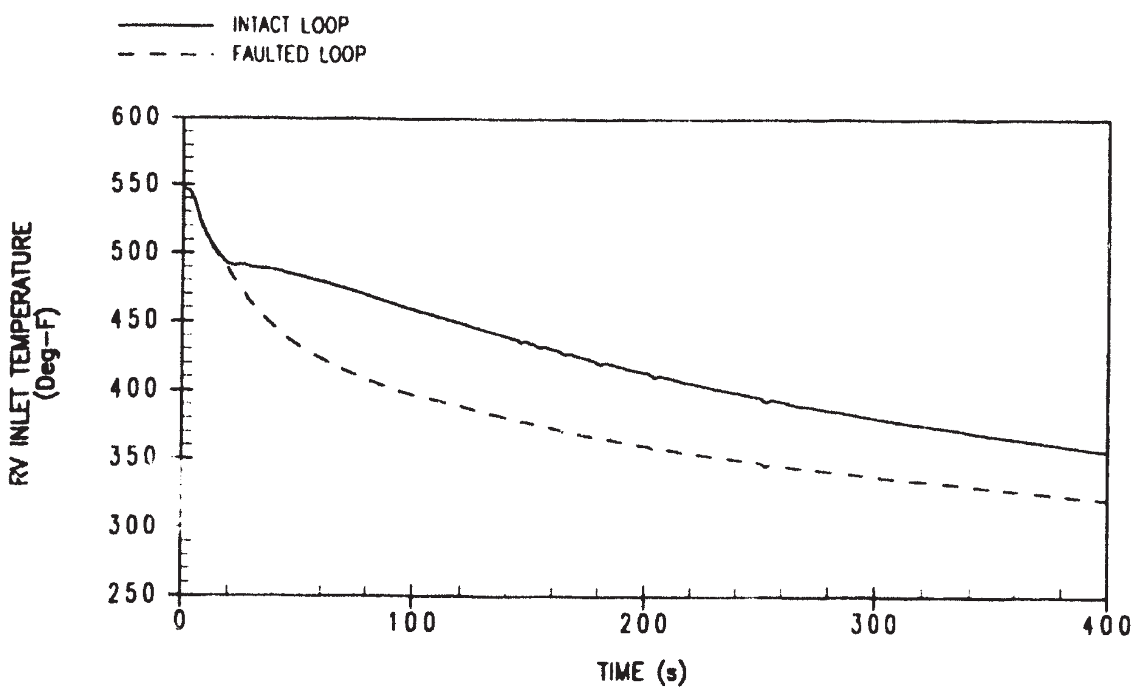


Figure 4.2.3-2
Steamline Break Transient with Offsite Power 1.069 ft² Double-Ended Rupture
Core Average Temperature and Reactor Vessel Inlet Temperature versus Time

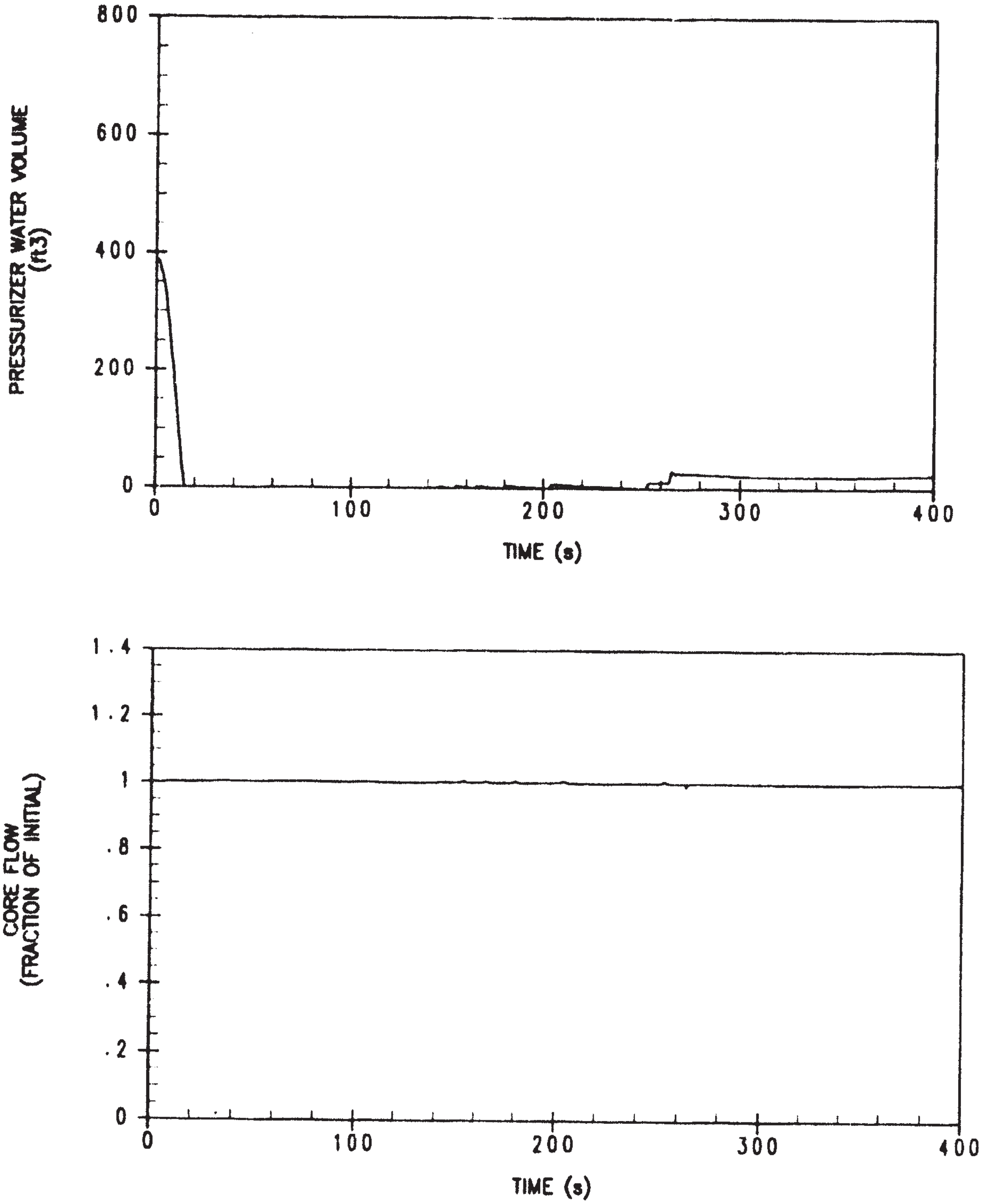
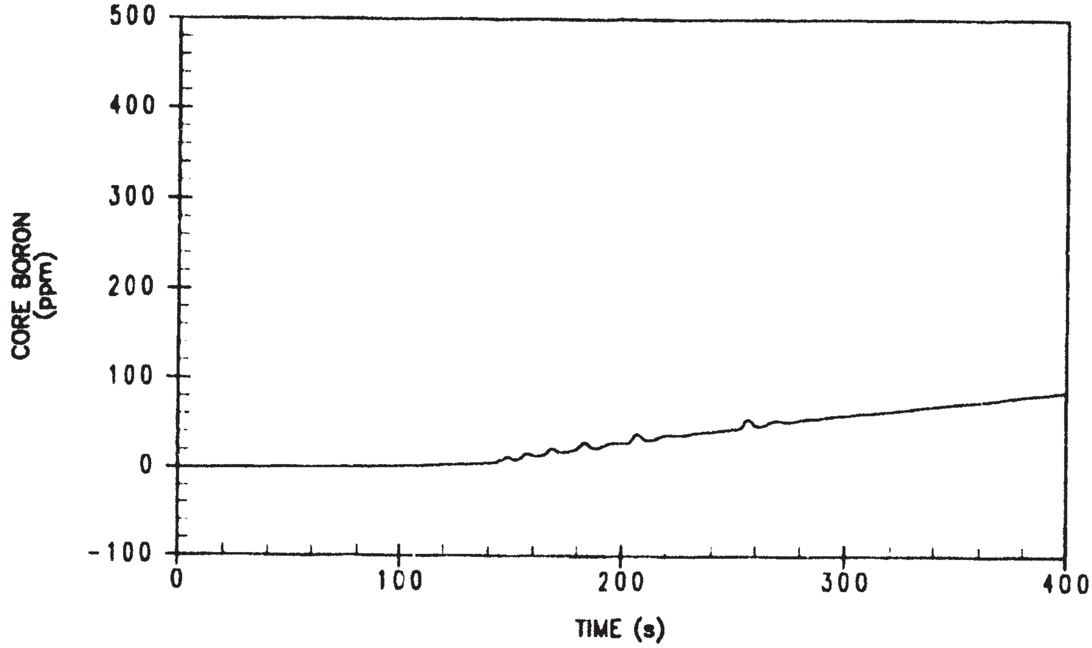


Figure 4.2.3-3
Steamline Break Transient with Offsite Power 1.069 ft^2 Double-Ended Rupture
Pressurizer Water Volume and Core Flow versus Time



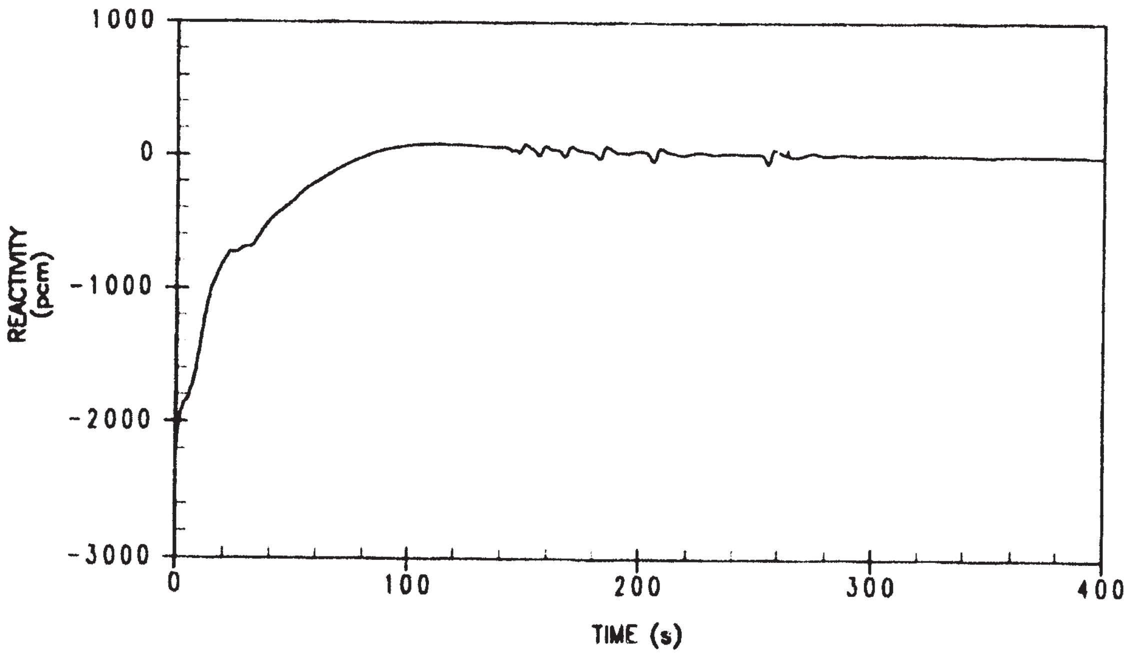


Figure 4.2.3-4
Steamline Break Transient with Offsite Power 1.069 ft^2 Double-Ended Rupture
Core Boron and Reactivity versus Time

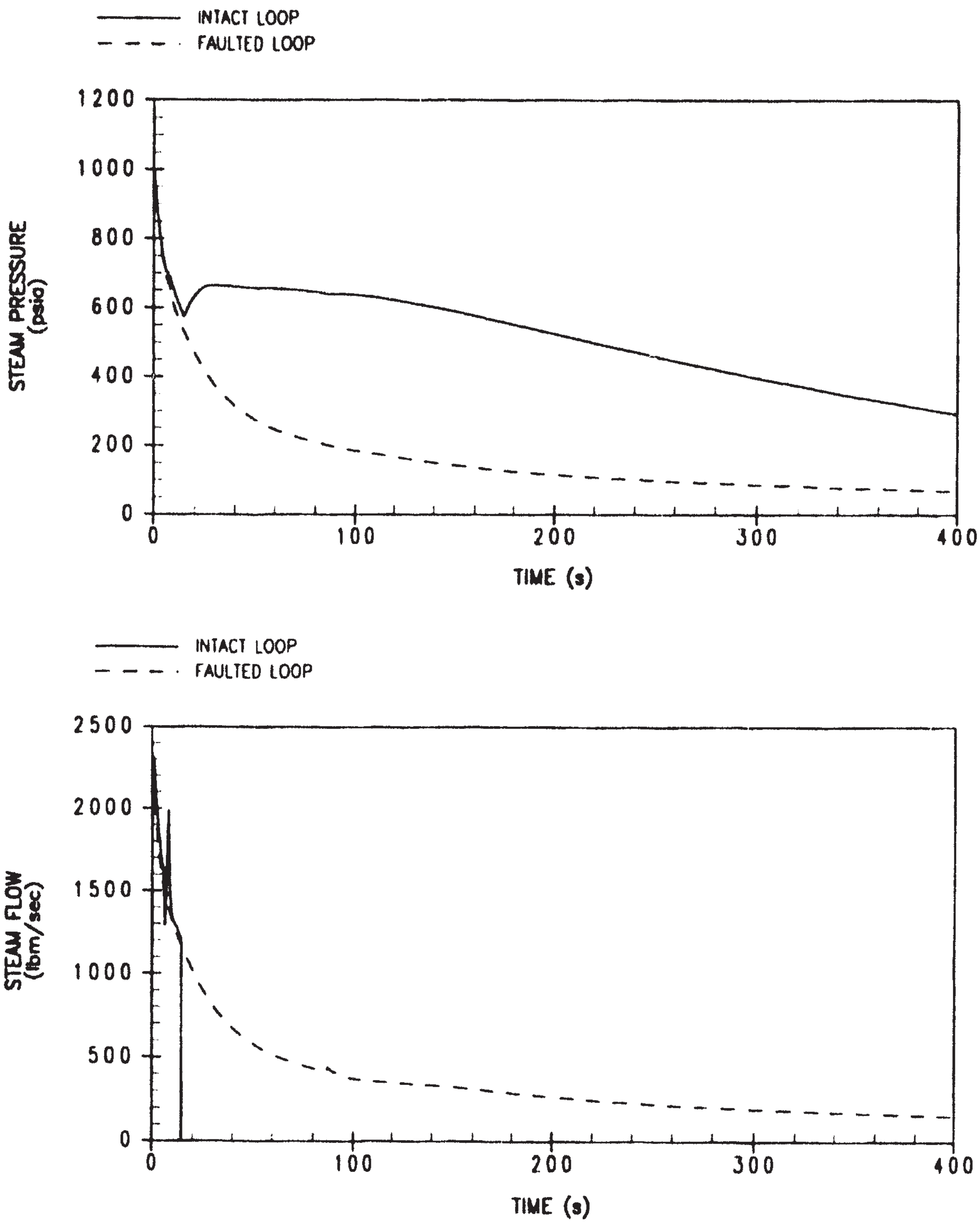


Figure 4.2.3-5
Steamline Break Transient with Offsite Power 1.069 ft^2 Double-Ended Rupture
Steam Pressure and Steam Flow versus Time

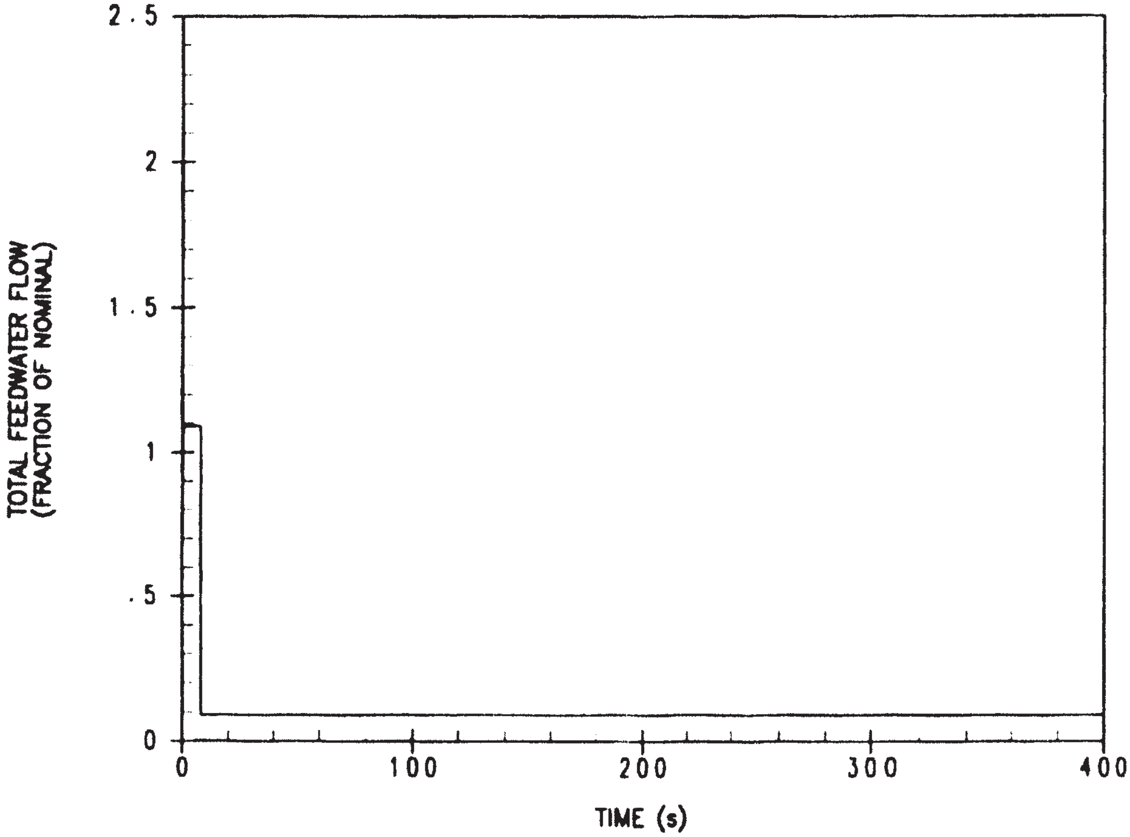
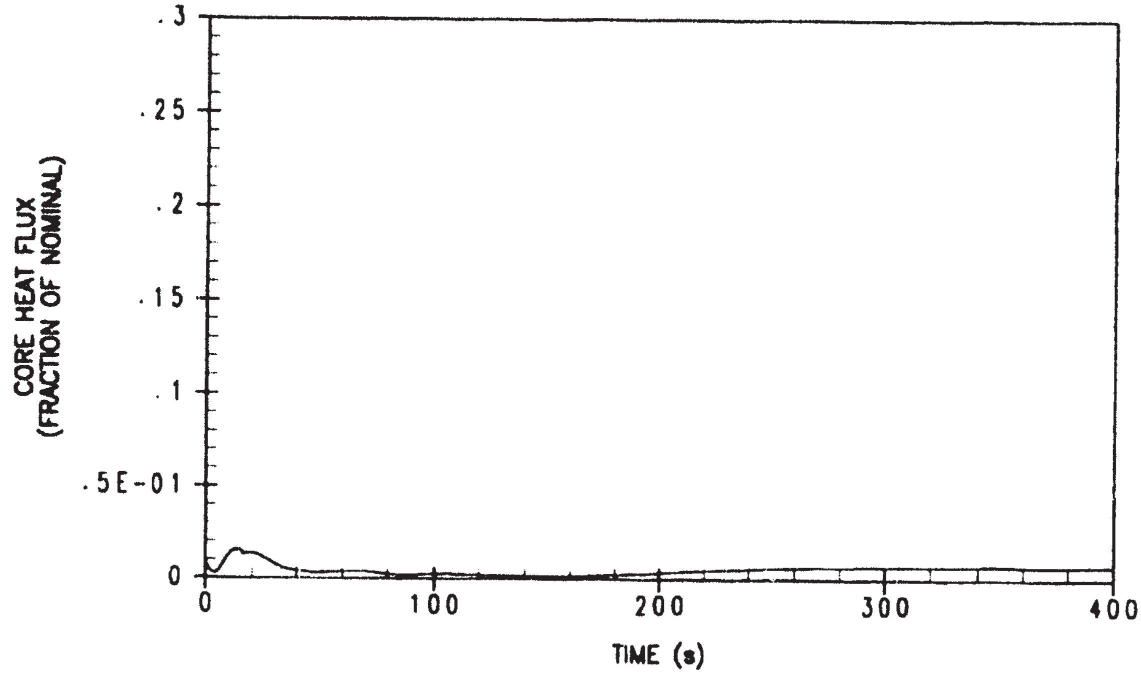


Figure 4.2.3-6
Steamline Break Transient with Offsite Power 1.069 ft² Double-Ended Rupture
Total Feedwater Flow versus Time



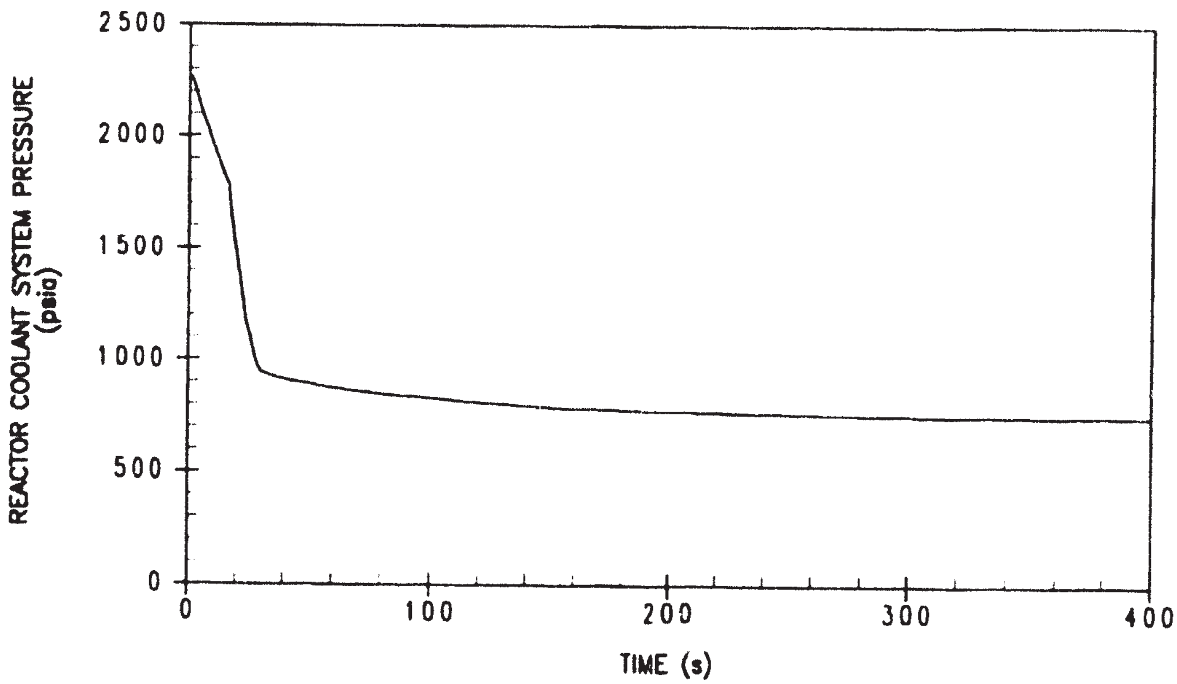


Figure 4.2.3-7
Steamline Break Transient without Offsite Power 1.069 ft^2 Double-Ended
Rupture Core Heat Flux and RCS Pressure versus Time

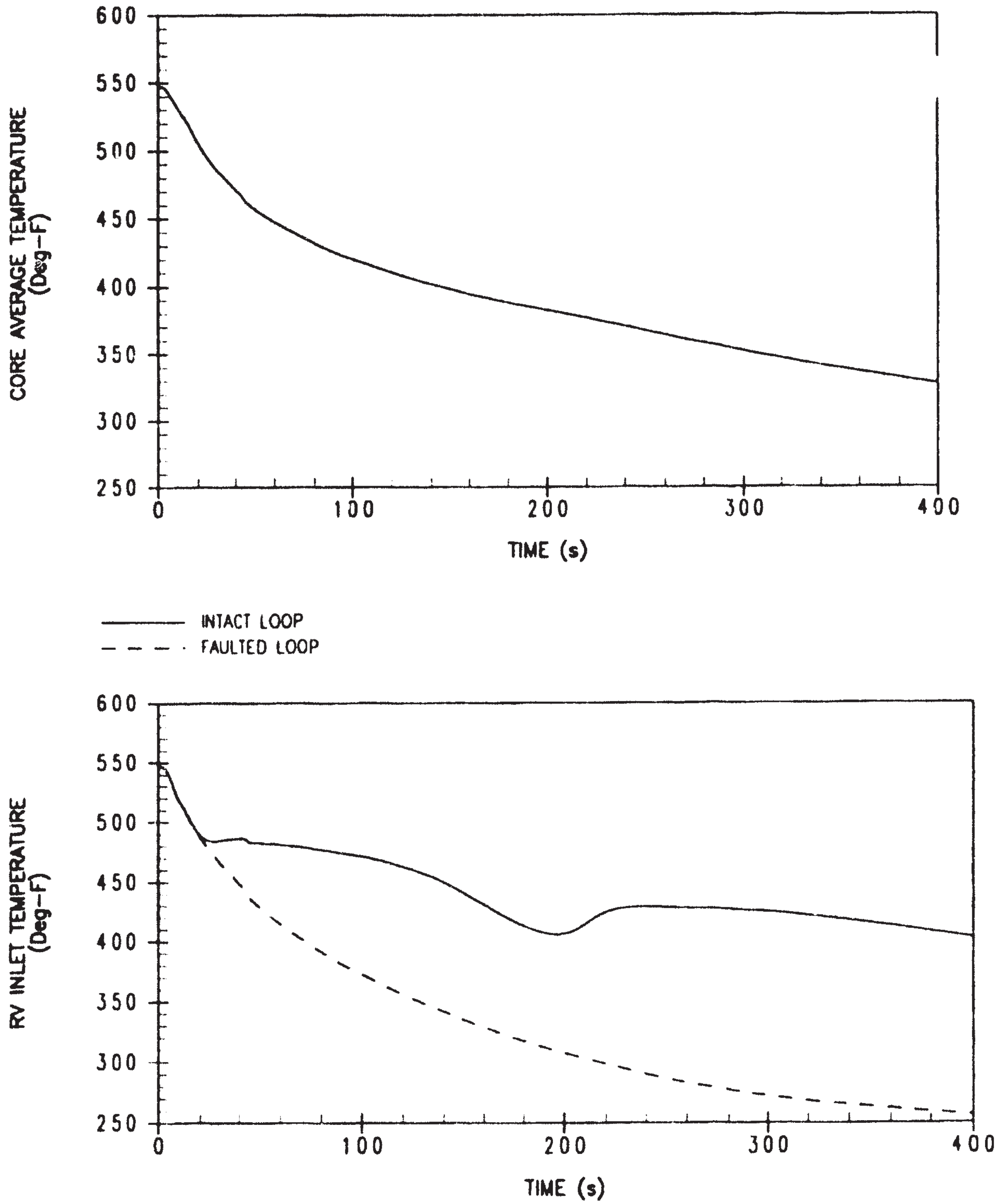


Figure 4.2.3-8
Steamline Break Transient without Offsite Power 1.069 ft^2 Double-Ended Rupture Core Average Temperature and Reactor Vessel Inlet Temperature versus Time

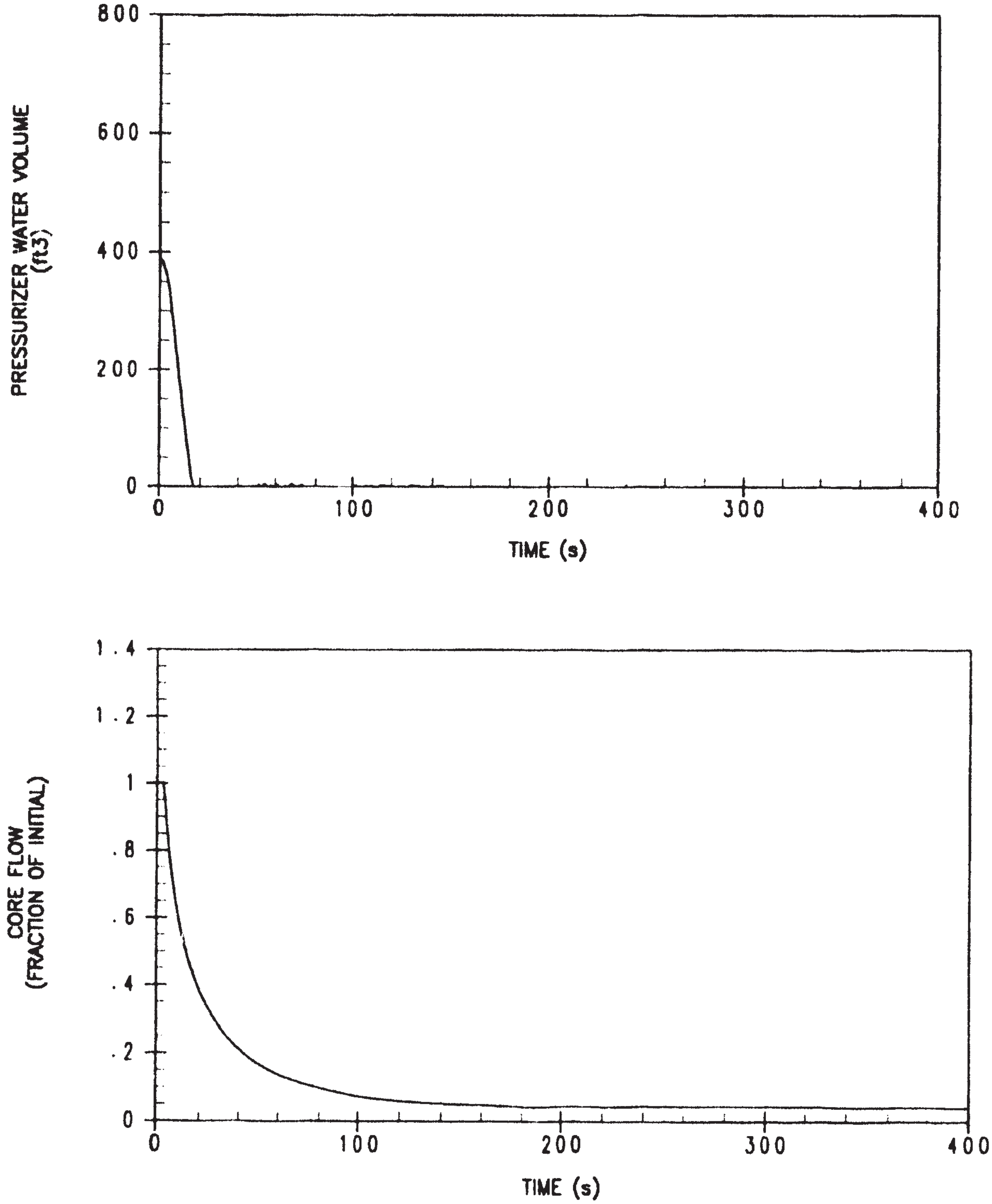


Figure 4.2.3-9
Steamline Break Transient without Offsite Power 1.069 ft² Double-Ended Rupture Pressurizer Water Volume and Core Flow versus Time

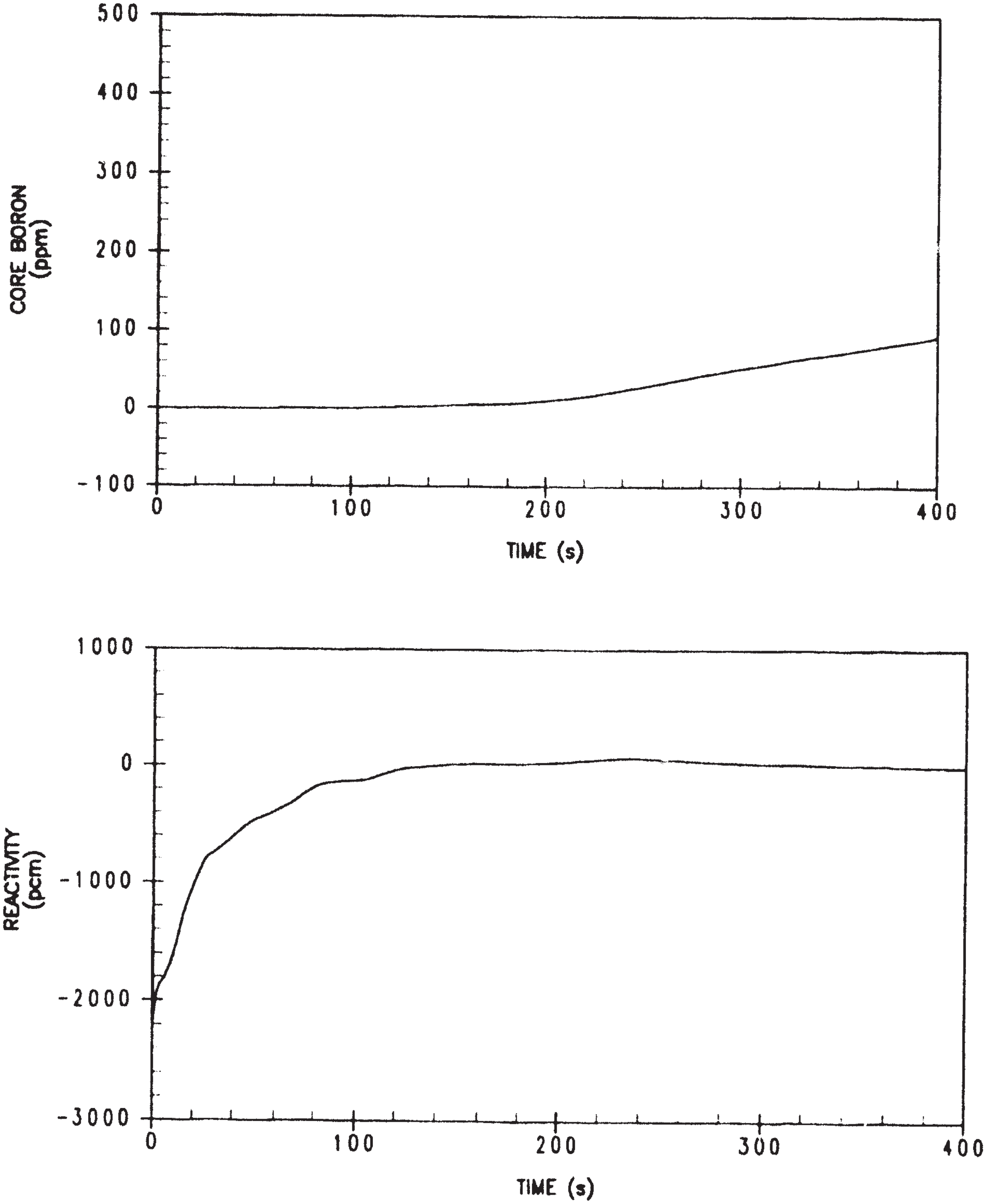


Figure 4.2.3-10
Steamline Break Transient without Offsite Power 1.069 ft² Double-Ended Rupture Core Boron and Reactivity versus Time

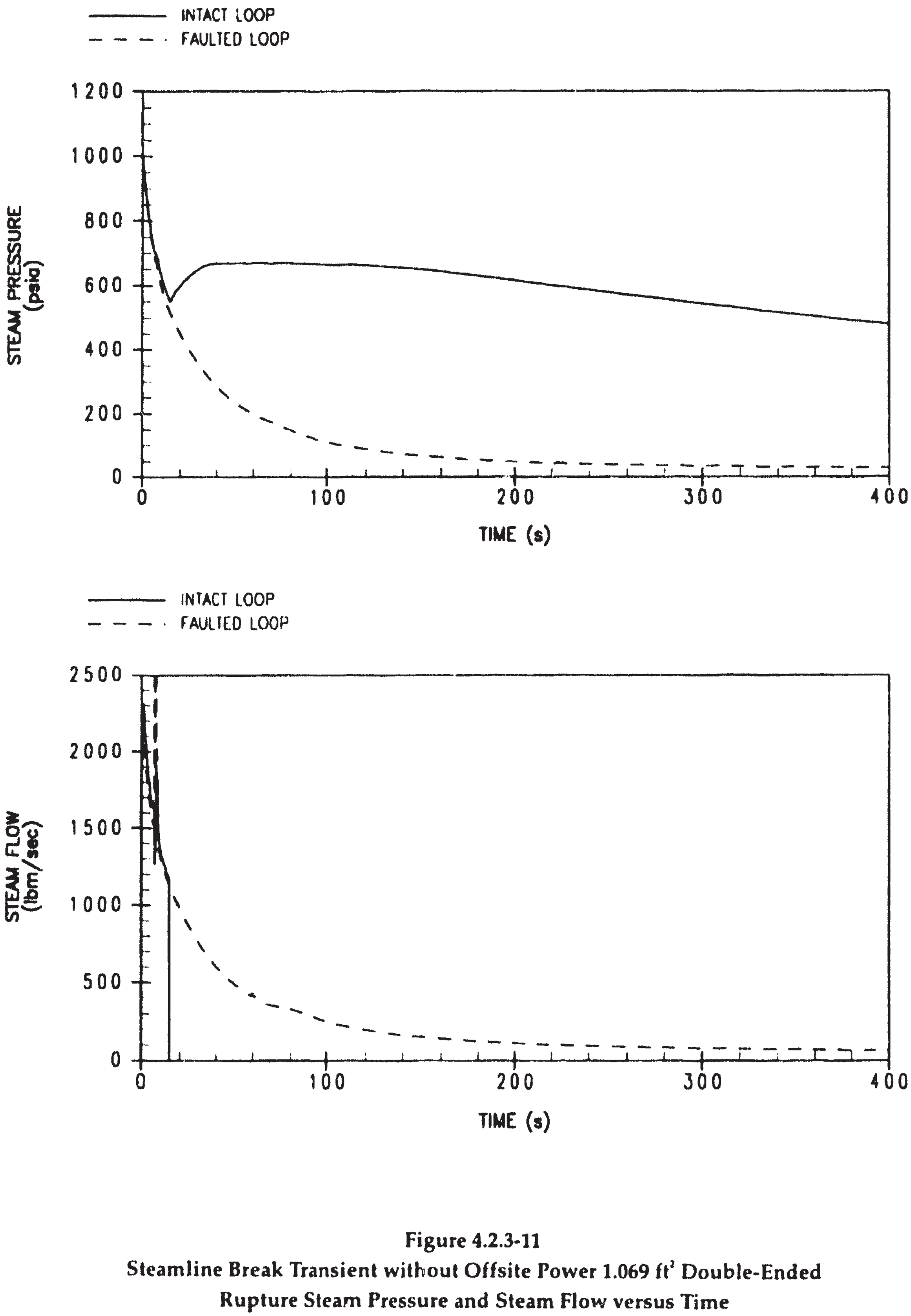


Figure 4.2.3-11
Steamline Break Transient without Offsite Power 1.069 ft^2 Double-Ended Rupture Steam Pressure and Steam Flow versus Time

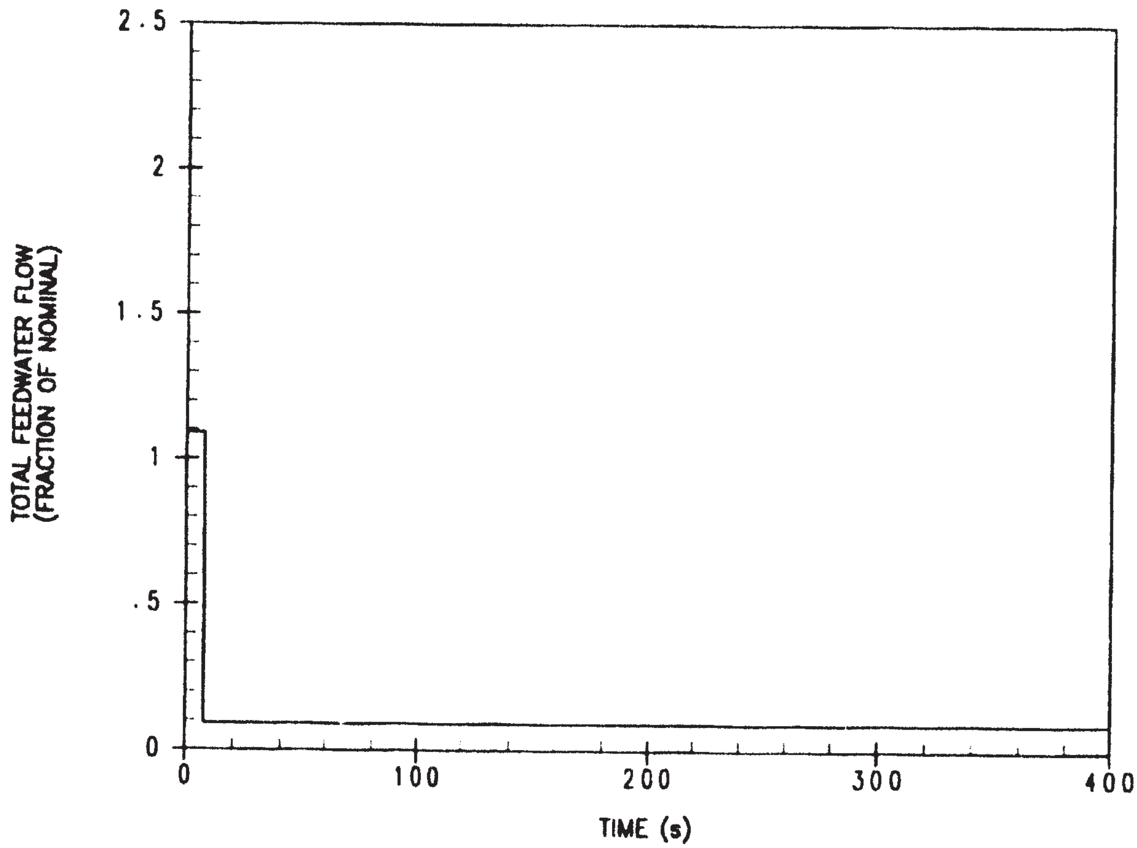


Figure 4.2.3-12
Steamline Break Transient without Offsite Power 1.069 ft^2 Double-Ended Rupture Total Feedwater Flow versus Time

4.2.4 Major Rupture of a Main Feedwater Pipe

T e major rupture of a main feedwater pipe accident was analyzed for the RSG Program. The analysis used the RETRAN-02 computer code. A detailed description of the analysis is provided in this section.

4.2.4.1 Identification of Causes and Accident Description

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of auxiliary feedwater to the effected steam generator. A break upstream of the feedline check valve would effect the NSSS only as a loss of feedwater. This case is covered by the evaluation in Section 4.2.1.

A feedline rupture reduces the ability to remove heat generated by the core from the RCS. The AFW is provided to ensure that adequate feedwater will be available to provide decay heat removal.

A feedline rupture reduces the ability to remove heat generated by the core from the RCS because of the following reasons:

- Feedwater to the steam generators is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip.
- Liquid in the steam generator may be discharged through the break, and would then not be available for decay heat removal after trip.
- The break may be large enough to prevent the addition of any main feedwater.

An AFWS is provided to ensure that adequate feedwater will be available to provide heat removal such that:

- No substantial overpressurization of the RCS shall occur.
- Liquid in the RCS shall be sufficient to cover the reactor core at all times.

The following provide the necessary protection against a main feedwater rupture:

A. A reactor trip on any of the following conditions:

   1. High-pressurizer pressure

2. Overtemperature ΔT

3. Low-low steam generator water level in any steam generator

B. Safety injection signal from any of the following:

a. Two of three low pressurizer pressure signals

b. Two of three high differential pressure signals between any steamline and remaining steamlines

c. Low main steamline pressure in any two of three lines

d. Two of three high (high-1) containment pressure

C. An AFWS to provide an assured source of feedwater to the steam generators for decay heat removal

4.2.4.2 Input Parameters and Assumptions

The primary assumptions for the major feedwater rupture analysis for all of the cases analyzed are as follows:

a. The plant is assumed to be initially operating at 102 percent of the NSSS power (2785 MWt). A conservatively high reactor coolant pump heat input of 15 MWt was assumed.

b. Uncertainties on initial operating conditions (power level, RCS temperature and pressurizer pressure) are applied in the limiting direction.

c. Pressurizer spray or PORVs or high pressurizer pressure reactor trip are not assumed.

d. Main feed to all steam generators is assumed to stop at the time the break occurs (i.e., all main feedwater spills).

e. A conservative break discharge quality is calculated by the RETRAN code. The quality changes as a function of the conditions in the steam generator.

f. The low-low steam generator water level protection function is not assumed until the water level reaches 0 percent NRS.

g. The worst possible break area is assumed; i.e., one that empties the affected steam generator and causes a reactor trip on low-low steam generator water level as assumed above. This assumption minimizes the steam generator fluid inventory at the time of trip, and thereby, maximizes the resultant heatup of the reactor coolant.

h. Heat energy deposited in RCS metal during the RCS heatup is not assumed.

i. Charging and letdown are not assumed.

j. Steam generator heat transfer area is assumed to decrease as the shell-side liquid inventory decreases.

k. The ANS-5.1-1979 standard residual decay heat model (Reference 1) is assumed based on long-term operation at the initial power level preceding the trip.

l. Analyses are performed without offsite power. When a loss of offsite electrical power is assumed after the reactor trip, the reactor coolant flow decreases to natural circulation.

The following describes input assumptions specific to each of Case A and B.

Case A

a. After operator action to isolate the faulted loop, Case A assumes AFW is initiated 10 minutes after the trip at a rate of 350 gpm. The AFW line purge volume is conservatively assumed to be the maximum value for either unit of 140 ft^3 and the initial AFW enthalpy is assumed to be 80.83 Btu/lbm.

b. Limiting reactivity coefficients reflecting maximum feedback are assumed.

Case B

a. AFW is automatically initiated 1 minute after the trip at a rate of 150 gpm after a conservative delay for AFW pump startup. After operator action to isolate the faulted loop, AFW is then increased to 350 gpm 30 minutes after trip. The AFW line purge volume is conservatively assumed to be the maximum value for either unit of 140 ft^3 and the initial AFW enthalpy is assumed to be 80.83 Btu/lbm.

b. Limiting reactivity coefficients reflecting minimum feedback are assumed.

4.2.4.3 Description of Analysis

The transient response following a feedwater pipe rupture event is calculated by a detailed digital simulation of the plant. The analysis models a simultaneous loss of main feedwater to all steam generators and subsequent reverse blowdown of the faulted steam generator.

A detailed analysis using the RETRAN-02 (Reference 2) computer code is performed to determine the plant transient conditions following a feedwater system pipe rupture. The code models the core neutron kinetics, RCS, pressurizer, steam generators, SIS, and the AFWS. The code computes pertinent variables, including the core heat flux, RCS temperature and pressure. Details of the Westinghouse PWR RETRAN model are documented in Reference 3.

4.2.4.4 Acceptance Criteria

The feedline rupture accident is an ANS Condition IV occurrence. Condition IV events are faults that are not expected to occur, but are postulated because their consequences would include the potential for release of significant amounts of radioactive material.

The Standard Review Plan (Revision 1) requires that the specific criteria used in evaluating the consequences of the feedline rupture shall be:

1. Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures.

2. Any fuel damage that may occur during the transient should be of a sufficiently limited extent so that the core will remain in place and geometrically intact with no loss of core cooling capability.

3. Any activity release must be such that the calculated doses at the site boundary are within a small fraction of the guidelines of 10 CFR Part 100.

To conservatively ensure meeting these basic criteria, the internal criterion established within Westinghouse is that no bulk boiling occurs in the primary coolant system following a feedline rupture prior to the time that the heat removal capability of the steam generators, being fed auxiliary feedwater, exceeds NSSS residual heat generation.

4.2.4.5 Results

Case A

Figures 4.2.4-1 and 4.2.4-2 show the calculated plant parameters following a feedline rupture for Case A. The assumed AFW flowrate is capable of removing decay heat 1850 seconds after trip. After this time, core decay heat decreases below the auxiliary feedwater heat removal capacity and reactor coolant temperatures and pressures decrease. The calculated sequence of events for this case is presented in Table 4.2.4-1.

Case B

Figures 4.2.4-3 and 4.2.4-4 show the calculated plant parameters following a feedline rupture for Case B. The assumed AFW flowrate is capable of removing decay heat approximately 2120 seconds after trip. After this time, core decay heat decreases below the auxiliary feedwater heat removal capacity and reactor coolant temperatures and pressures decrease. The calculated sequence of events for Case B is presented in Table 4.2.4-1.

4.2.4.6 Conclusions

Results of the evaluation show that for the postulated feedline rupture, the assumed AFWS capacity is adequate to remove core decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core.

4.2.4.7 References

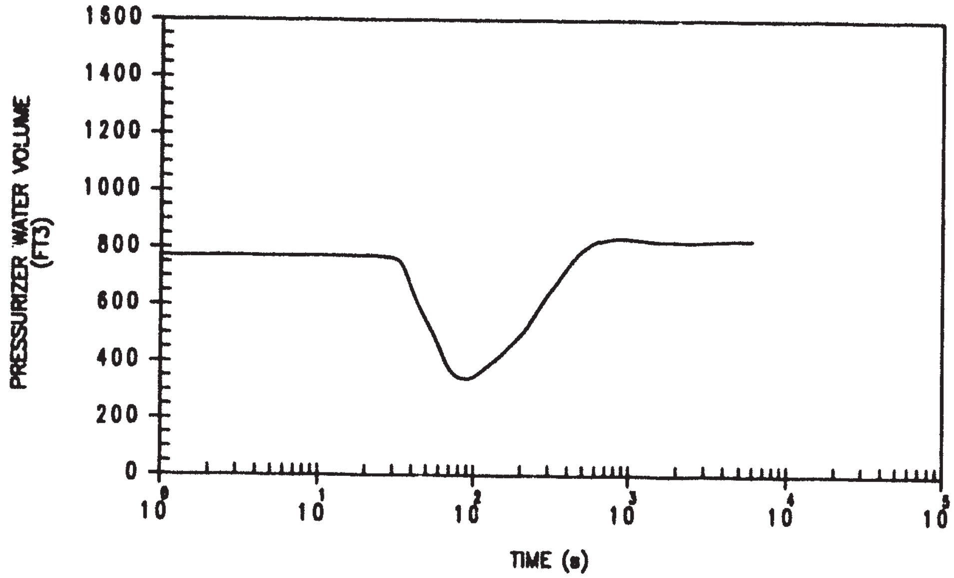
1. *American National Standard for Decay Heat Power in Light Water Reactors*, ANSI/ANS-5.1-1979, August 29, 1979

2. C. E. Peterson, et al., *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, EPRI NP-1850-CCM, Rev. 6, December 1995

3. Huegel, D. S., et al., *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, WCAP-14882 (Proprietary), June 1997

Table 4.2.4-1
Time Sequence of Events for Major Rupture of a Main Feedwater Pipe

	Event	Time (seconds)
Case A		
	Feedline Rupture Occurs	20.0
	Low-Low SG Water Level Signal	27.8
	Rods Begin to Fall	29.8
	Steamline Isolation Occurs	64.6
	Auxiliary Feedwater Flow Initiated at 350 gpm	627.8
	Peak Water Level in Pressurizer Occurs	863.0
	Core Decay Heat Decreases to Auxiliary Feedwater Heat Removal Capacity	1850.0
Case B		
	Feedline Rupture Occurs	20.0
	Low-Low SG Water Level Signal	27.8
	Rods Begin to Fall	29.8
	Steamline Isolation Occurs	65.0
	Auxiliary Feedwater Flow Initiated at 150 gpm	87.8
	Peak Water Level in Pressurizer Occurs	1736.0
	Auxiliary Feedwater Flow Increased to 350 gpm	1827.8
	Core Decay Heat Decreases to Auxiliary Feedwater Heat Removal Capacity	2120.0



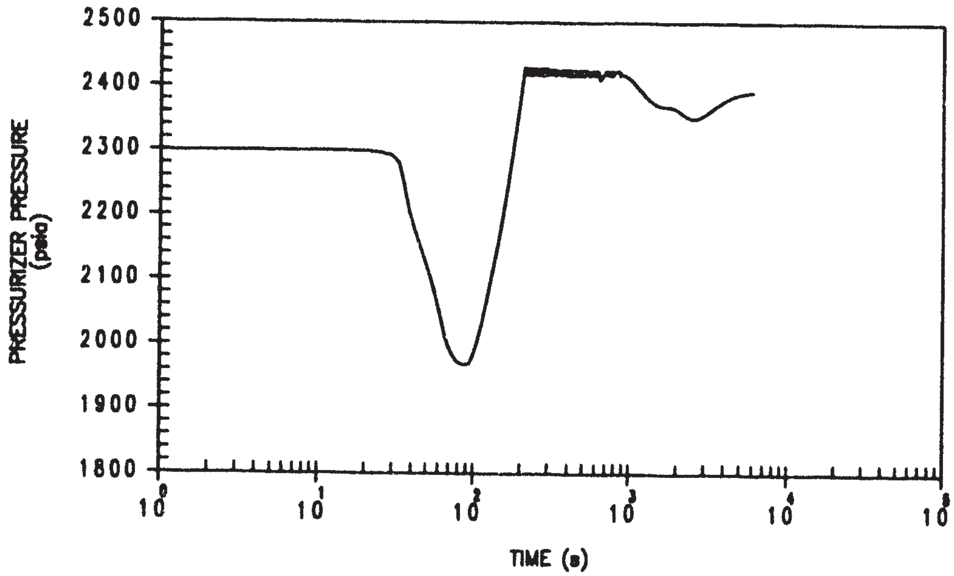


Figure 4.2.4-1
Major Feedline Break, Case A, Pressurizer Water Volume and Pressurizer Pressure versus Time

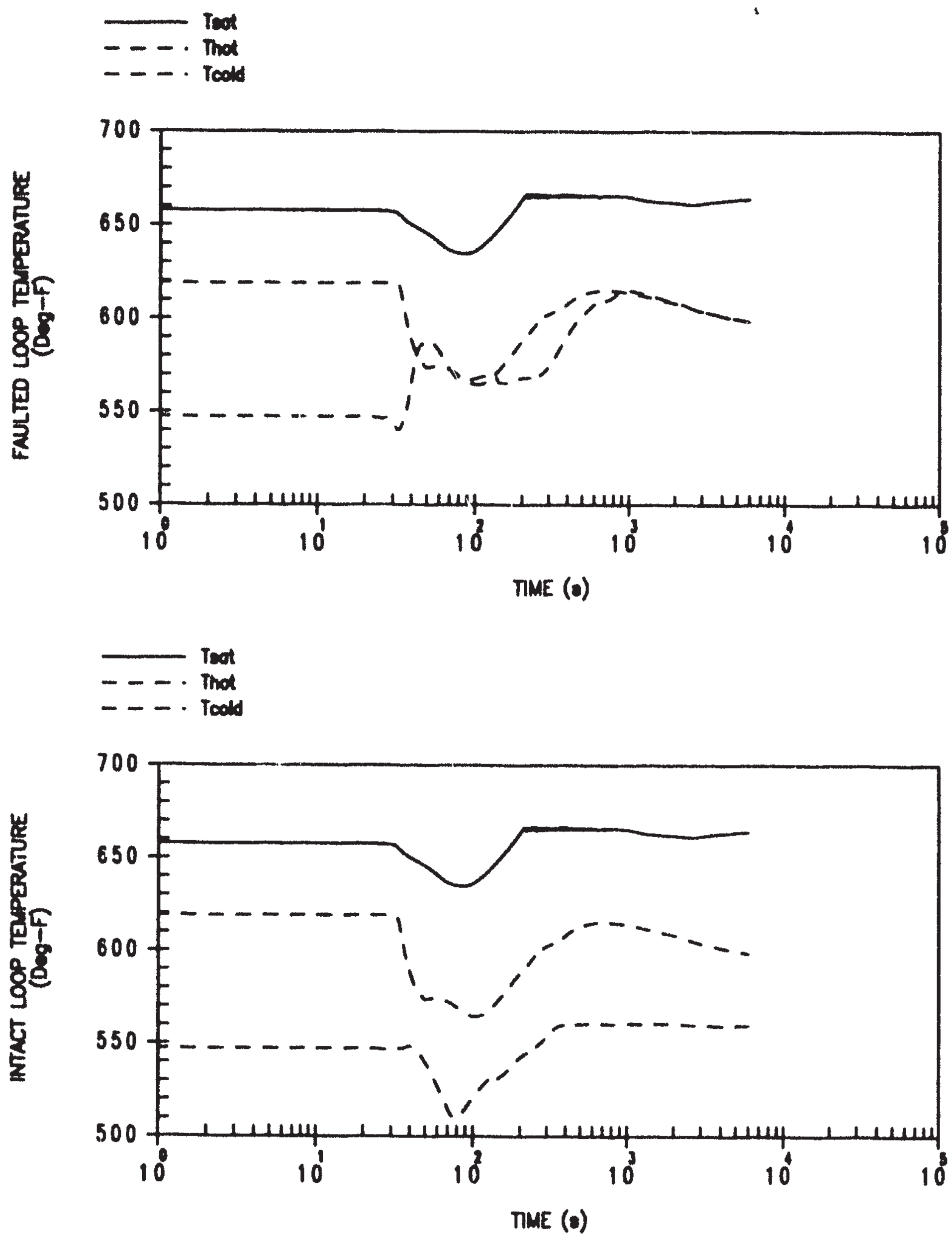
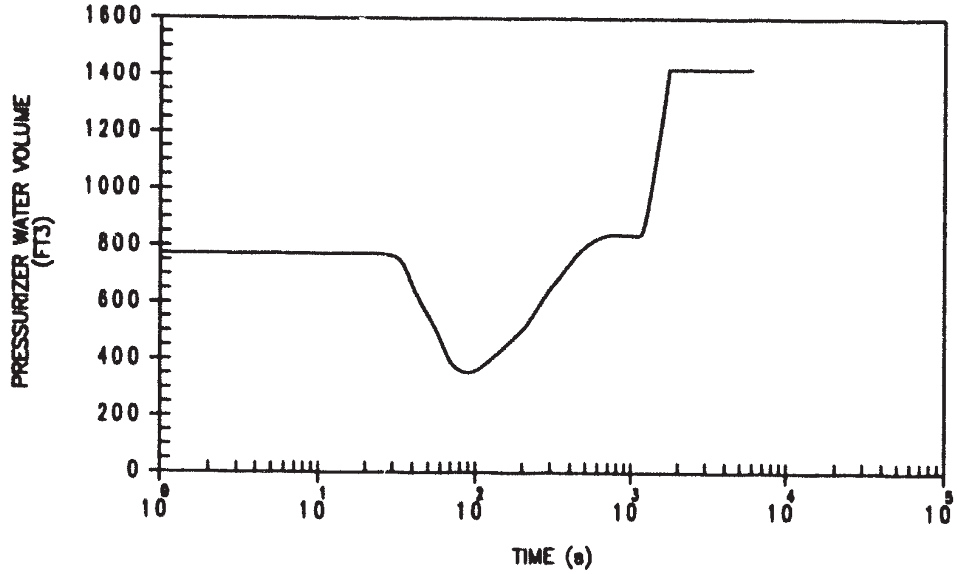


Figure 4.2.4-2
Major Feedline Break, Case A, Faulted and
Intact Loop Temperatures versus Time



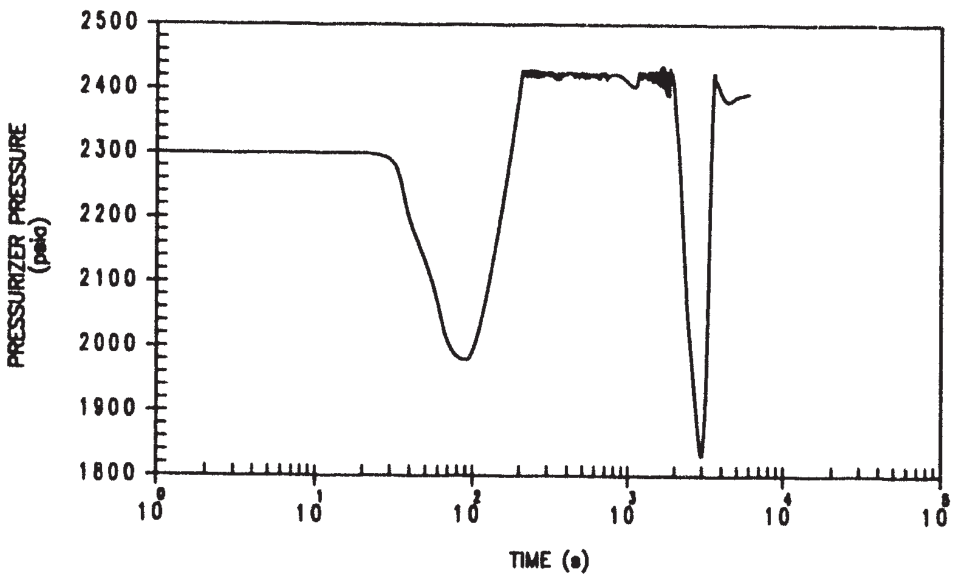


Figure 4.2.4-3
Major Feedline Break, Case B, Pressurizer Water Volume and Pressurizer Pressure versus Time

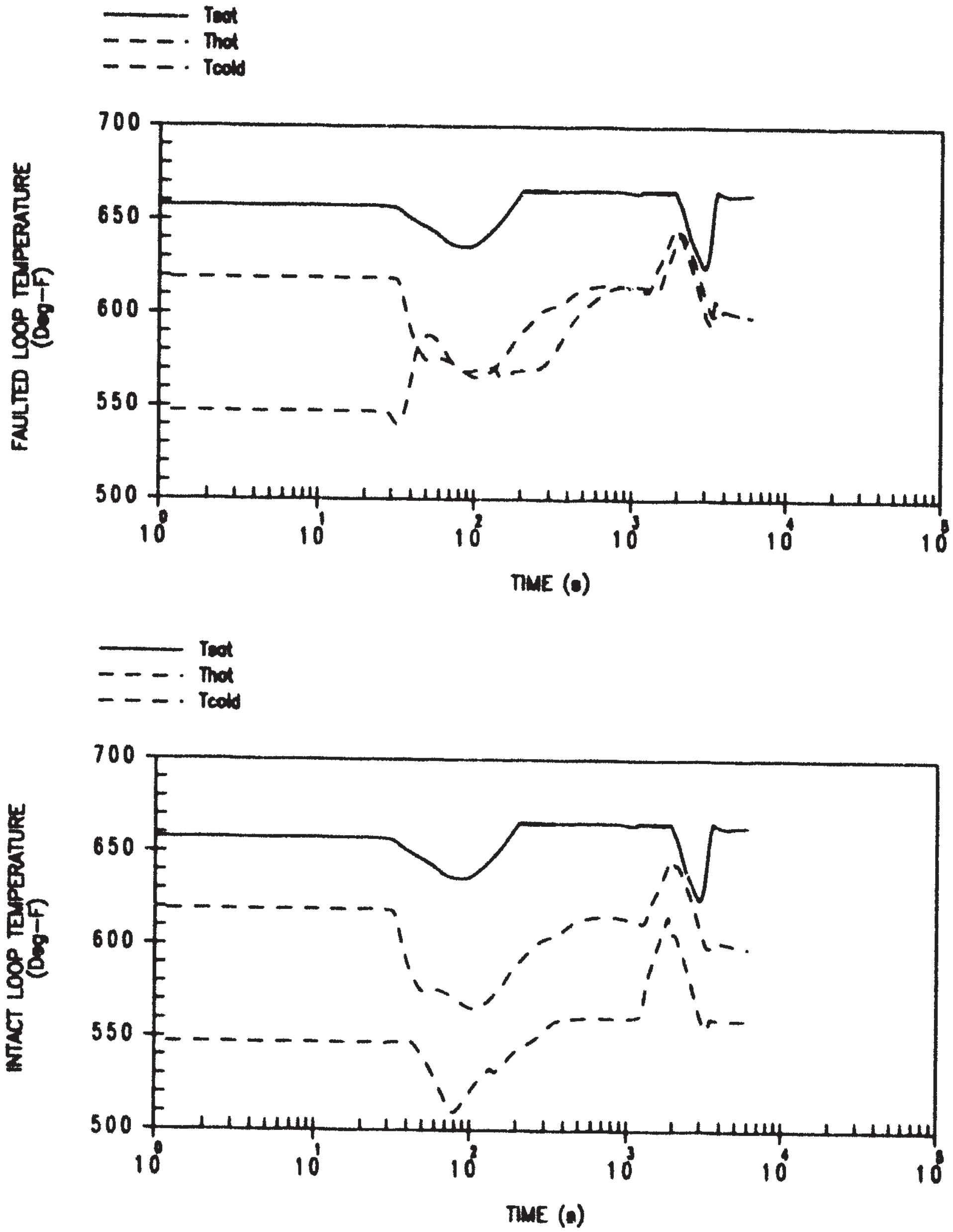


Figure 4.2.4-4
Major Feedline Break, Case B, Faulted and Intact Loop Temperatures versus Time

4.3 SGTR TRANSIENT

4.3.1 Introduction

In support of the Farley Units 1 and 2 RSG Program, a SGTR thermal-hydraulic analysis for calculation of the radiological consequences has been performed. The SGTR analysis continues to support a T_{avg} window range of 567.2°F to 577.2°F, which was included as part of the power uprate effort. Plant secondary side conditions (e.g., steam pressure, flow, temperature) are based on high and low tube plugging (0 percent up to 15 percent average/20 percent peak) to bound all possible conditions. Therefore, four separate cases have been analyzed for the SGTR analysis as follows.

1. T_{avg} = 577.2°F and SGTP = 0 percent (PCWG Case 1)
2. T_{avg} = 577.2°F and SGTP = 20 percent average/peak (PCWG Case 3)
3. T_{avg} = 567.2°F and SGTP = 0 percent (PCWG Case 4)
4. T_{avg} = 567.2°F and SGTP = 20 percent average/peak (PCWG Case 6)

The major hazard associated with a SGTR event is the radiological consequences resulting from the transfer of radioactive reactor coolant to the secondary side of the ruptured steam generator and subsequent release of radioactivity to the atmosphere. Acceptance criteria for offsite doses are expressed as maximum allowed gamma body and thyroid doses at the exclusion area boundary and low population zone as defined in Standard Review Plan 15.6.3. The primary thermal-hydraulic parameters that effect the calculation of offsite doses for an SGTR include the amount of reactor coolant transferred to the secondary side of the ruptured steam generator, the amount of primary-to-secondary break flow that flashes to steam and the amount of steam released from the ruptured steam generator to the atmosphere.

The accident analyzed is the double-ended rupture of a single steam generator tube. It is assumed that the primary-to-secondary break flow following a SGTR results in depressurization of the RCS, and that reactor trip and SI are automatically initiated on low pressurizer pressure. Loss of offsite power is assumed to occur at reactor trip resulting in the release of steam to the atmosphere via the steam generator atmospheric relief valves and/or safety valves. Following SI actuation, it is assumed that the RCS pressure stabilizes at the value where the SI and break flowrates are equal. The equilibrium primary-to-secondary break flow is assumed to persist until 30 minutes after the initiation of the SGTR, at which time it is assumed that the operators have completed the actions necessary to terminate the break flow and the steam releases from the ruptured steam generator. This action is consistent with the original Farley licensing basis for SGTR events.

After 30 minutes, it is assumed in the FSAR analysis that steam is released only from the intact steam generators to dissipate the core decay heat and to subsequently cool the plant down to the RHRS operating conditions. It is assumed that plant cooldown to RHRS operating conditions is accomplished within 8 hours after initiation of the SGTR and that steam releases are terminated at that time. A primary and secondary side mass and energy balance is used to calculate the steam release and feedwater flow for the intact steam generators from 0 to 2 hours and from 2 to 8 hours.

4.3.2 Input Parameters and Assumptions

The primary and secondary side operating conditions used in this analysis are summarized in Section 3. A summary of key input assumptions for the SGTR event follows.

HHSI FLOWRATES

A larger SI flowrate results in a greater RCS equilibrium pressure and, consequently, higher break flow. Maximum HHSI flowrates are therefore assumed for this analysis.

RHR CUT-IN TIME

The RHRS cut-in time based on the RCS heat load and RHRS heat removal capacity is conservatively calculated and modeled in the SGTR analysis. This cut-in time affects the duration of long-term steam releases from the intact steam generators to the atmosphere following termination of the break flow. The effect of RHR cut-in time on long-term doses, however, is not significant since the radiation released from the intact steam generators is small relative to that released by the ruptured steam generator. An RHRS cut-in time of 8 hours has been assumed and shown to be sufficient.

MISCELLANEOUS PARAMETER ASSUMPTIONS

- Low pressurizer pressure SI actuation setpoint = 1864.7 psia
- Lowest steam generator safety valve reseat pressure = 949.95 psia - includes 13 percent MSSV blowdown, which covers the -3 percent safety valve setpoint tolerance

4.3.3 Description of Analyses Performed

A T_{avg} window of 567.2°F to 577.2°F is considered. Section 3.1 documents six PCWG cases that have been used for the Farley RSG Program.

PCWG Cases 1, 2, and 3 assume at a T_{avg} of 577.2°F, while PCWG Cases 4, 5, and 6 assume at a T_{avg} of 567.2°F. The SGTR analysis employed PCWG Cases 1 and 4 with no tube plugging. In addition, PCWG Cases 3 and 6, with a uniform tube plugging level of 20 percent[2] were used to support the maximum SGTP . The cases with 15 percent average SGTP (Cases 2 and 5) are not considered since they are bounded by the cases with minimum and maximum tube plugging.

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[2] Table 3.1-2 specifies that a minimum steam pressure of 675 psia for 20 percent SGTP should be assumed for analysis purposes. The SGTR analysis used the lower value listed in the PCWG tables (656 psia) for additional conservatism.

All the cases support an NSSS power of 2785 MWt, TDF of 86,000 gpm/loop, and the current 17 x 17 V5 fuel.

BREAK FLOW, STEAM RELEASES, AND FEEDWATER FLOWS

In total, four cases were considered in the SGTR thermal-hydraulic analysis to bound the operating conditions for the RSG. Note that these four cases are individually analyzed to determine the limiting steam release and limiting break flow between 0 and 30 minutes (break flow termination) for the radiological consequences calculation. A single calculation is performed to determine long-term steam releases from, and feedwater flow to, the intact steam generators for the time interval from the start of the event (0 hours) to 2 hours and from 2 hours to RHR cut-in at 8 hours. The 0- to 2-hour calculations use the 0 to 30 minute intact steam generator steam release and feedwater flow results from the case that resulted in the highest intact steam generator steam and feedwater flowrates.

BREAK FLOW FLASHING FRACTION

A portion of the break flow will flash directly to steam upon entering the secondary side of the ruptured steam generator. As a condition to the power uprate licensing amendment, the NRC required SNC to provide an SGTR analysis that incorporates a break flow flashing fraction that is appropriate for the Farley design. Since a transient break flow calculation is not performed for Farley, a detailed time dependent flashing fraction that incorporates the expected changes in primary-side temperatures can not be calculated. Instead, a conservative calculation of the flashing fraction is performed using the limiting conditions from the break flow calculation cases. Two time intervals are considered, as in the break flow calculations; pre- and post-reactor trip (SI initiation occurs concurrently with reactor trip). Since the RCS and steam generator conditions are different before and after the trip, different flashing fractions would be expected.

The flashing fraction is based on the difference between the primary-side fluid enthalpy and the saturation enthalpy on the secondary side. Therefore, the highest flashing will be predicted for the case with the highest primary-side temperatures. For the flashing fraction calculations, it is conservatively assumed that all of the break flow is at the hot leg temperature (the break is assumed to be on the hot leg side of the steam generator). Similarly, a lower secondary-side pressure maximizes the difference in the primary and secondary enthalpies, although a lower pressure will have a higher heat of vaporization which would result in less flashing. The highest possible pre-trip flashing fraction, based on the range of operating conditions covered by this analysis, is for a case with a hot leg temperature of 613.3°F, initial RCS pressure of 2250 psia, and initial secondary pressure of 656 psia[2]. (This represents a combination of Cases 3 and 6 from Table 3.1-2). All cases consider the same post-trip RCS pressure of 2030 psia and post-trip steam generator pressure of 949.95 psia. The highest post-trip flashing fraction, based

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[2] Table 3.1-2 specifies that a minimum steam pressure of 675 psia for 20 percent SGTP should be assumed for analysis purposes. The SGTR analysis used the lower value listed in the PCWG tables (656 psia) for additional conservatism.

on the range of operating temperatures covered by this analysis, is for a case with a hot leg temperature of 613.3°F (Cases 1 and 3 from Table 3.1-2). It is conservatively assumed that the hot leg temperature is not reduced for the 30 minutes in which break flow is calculated.

4.3.4 Results

The tube rupture break flow and ruptured steam generator atmospheric steam releases from 0 to 30 minutes, for the four different SGTR cases discussed in Section 4.3.3, are summarized in Table 4.3-1. Based on the results of these four SGTR cases, bounding values for break flow and steam releases are provided in Table 4.3-2, along with the long-term steam releases, feedwater flows, and steam generator water mass data for use in radiological consequences analysis. For a SGTR event, the amount of radioactivity released to the atmosphere is directly proportional to the amount of steam released through the safety valves associated with the ruptured steam generator. Therefore, the worst radiological consequences result from the SGTR case with the greatest amount of steam released. Likewise, a greater break flow results in greater radiological contamination of the secondary side which, in turn, results in a greater amount of activity released along with the steam. Maximum break flow and steam release, therefore, represent bounding values that are conservative for an offsite dose evaluation.

Table 4.3-3 shows the information from Table 4.3-2 with an approximate 10 percent increase in mass flowrates for use in a more conservative radiological analysis. Increasing the mass transfer data prior to performing the radiological consequences analysis allows future plant changes that result in small increases in the mass transfer rates to be evaluated without requiring the radiological analysis to be redone.

The SGTR thermal-hydraulic analysis results for the RSG can be compared to the Farley FSAR results. Per the Farley FSAR, 150,000 lbm of reactor coolant are discharged into the ruptured steam generator and 73,300 lbm of steam are released to the atmosphere during the 30-minute period assumed for isolation of the affected steam generator. Table 4.3-2 shows that for the RSG analysis, 143,400 lbm of reactor coolant are discharged into the steam generator and 71,100 lbm of steam are released to the atmosphere. The analysis results presented in the FSAR were increased by 10 percent for additional conservatism. With the addition of 10 percent to the calculated results for the RSG as shown in Table 4.3-3, the FSAR break flow and steam releases are exceeded by a small amount (5.3 percent and 7.8 percent, respectively).

The change in primary to secondary break flow is attributed to small, conservative changes in the calculation of the equilibrium break flowrate and the lower initial steam generator pressure considered for the RSG Program. The change in steam releases is attributed to the increase in dry weight of the RSGs relative to the Model 51 steam generators.

Table 4.3-4 shows that the conservatively high bounding calculation of the pre-trip flashing fraction is 0.2079 and the post-trip flashing fraction is 0.1507. The table presents the bounding values for break flow, steam release, and feedwater flow with the first 30 minutes of the event separated into pre-, and post-trip time periods for use with the different calculated break flow flashing fractions. Table 4.3-5 shows the same data with an approximate 10-percent increase in break flow and steam releases for use in a more conservative radiological analysis.

4.3.5 Conclusions

The SGTR thermal-hydraulic analysis for use in the radiological consequences calculation has been completed in support of the Farley RSG Program. Based on a primary and secondary side mass and energy balance, the break flow and atmospheric steam releases from the ruptured and intact steam generators were calculated for 30 minutes. After 30 minutes, it was assumed that steam is released only from the intact steam generators to dissipate the core decay heat and to subsequently cool the plant down to the RHRS operating conditions. For Farley, it was assumed that plant cooldown to RHRS operating conditions can be accomplished within 8 hours after initiation of the SGTR event and that steam releases are terminated at this time. A primary and secondary side mass and energy balance was used to calculate the steam release and feedwater flow for the intact steam generators from 0 to 2 hours and from 2 to 8 hours.

The SGTR thermal-hydraulic analysis results were compared to the Farley FSAR results. For the Model 54F RSGs, the resultant primary-to-secondary break flow and steam releases, increased by a small amount (5.3 percent and 7.5 percent, respectively). The results of the SGTR analysis were provided for use in the radiological consequences analysis (see BOP Licensing Report).

Table 4.3-1 Case-Specific SGTR Thermal-Hydraulic Results for the Farley RSG	
Tube Rupture Break Flow for 0 - 30 Minutes	
T_{avg} = 577.2°F, 0% SGTP	142,375 lbm
T_{avg} = 577.2°F, 20% SGTP	142,781 lbm
T_{avg} = 567.2°F, 0% SGTP	143,030 lbm
T_{avg} = 567.2°F, 20% SGTP	143,376 lbm
Steam Release from Ruptured SG for 0 - 30 Minutes	
T_{avg} = 577.2°F, 0% SGTP	71,019 lbm
T_{avg} = 577.2°F, 20% SGTP	68,651 lbm
T_{avg} = 567.2°F, 0% SGTP	66,822 lbm
T_{avg} = 567.2°F, 20% SGTP	64,400 lbm

Table 4.3-2
Bounding SGTR Thermal-Hydraulic Results for the Farley RSG Radiological Dose Analysis

Tube Rupture Break Flow for 0 - 30 Minutes	143,400 lbm
Steam Release from Ruptured SG for 0 - 30 Minutes	71,100 lbm
Steam Release from Intact SGs for 0 - 2 Hours	383,350 lbm
Feedwater Flow to Intact SGs for 0 - 2 Hours	296,980 lbm
Steam Release from Intact SGs for 2 - 8 Hours	848,760 lbm
Feedwater Flow to Intact SGs for 2 - 8 Hours	891,330 lbm
Initial Ruptured SG Water Mass	
Maximum	107,942 lbm
Minimum	104,193 lbm
Final Ruptured SG Water Mass	101,955 lbm

Table 4.3-3
Bounding SGTR Thermal-Hydraulic Results for the Farley RSG Radiological Dose Analysis with Additional 10 Percent Mass Flowrate

Tube Rupture Break Flow for 0 - 30 Minutes	158,000 lbm
Steam Release from Ruptured SG for 0 - 30 Minutes	79,000 lbm
Steam Release from Intact SGs for 0 - 2 Hours	422,000 lbm
Feedwater Flow to Intact SGs for 0 - 2 Hours	327,000 lbm
Steam Release from Intact SGs for 2 - 8 Hours	934,000 lbm
Feedwater Flow to Intact SGs for 2 - 8 Hours	981,000 lbm
Initial Ruptured SG Water Mass	
Maximum	107,942 lbm
Minimum	104,193 lbm
Final Ruptured SG Water Mass	101,955 lbm

Table 4.3-4 Bounding SGTR Thermal-Hydraulic Results with Break Flow Flashing Fraction for the Farley RSG Radiological Dose Analysis	
Reactor Trip, SI Actuation, and Loss Of Offsite Power	224.2 seconds(1)
Pre-Trip (less than 224.2 seconds)	
Tube Rupture Break Flow	19,620 lbm
Percentage of Break Flow that Flashes	20.79%
Steam Release Rate to Condenser	3400 lbm/sec for all SGs or 1133.3 lbm/sec for single SG
Post Trip (after 224.2 seconds)	
Tube Rupture Break Flow	123,770 lbm
Percentage of Break Flow that Flashes	15.07%
Steam Release from Ruptured SG up to 2 Hours	71,100 lbm
Steam Release from Intact SGs up to 2 Hours	383,350 lbm
Feedwater Flow to Intact SGs up to 2 Hours	296,980 lbm
Steam Release from Intact SGs for 2 - 8 Hours	848,760 lbm
Feedwater Flow to Intact SGs for 2 - 8 Hours	891,330 lbm
Initial Ruptured SG Water Mass Maximum Minimum	 107,942 lbm 104,193 lbm
Final Ruptured SG Water Mass	101,955 lbm

Notes:

(1) Assumes nominal Technical Specification SI Setpoint. To reach Safety Analysis Limit setpoint of 1700 psia an additional 100 seconds should be assumed. This may be conservative for determining when the control room emergency heating, ventilation, and air conditioning will actuate.

Table 4.3-5 Bounding SGTR Thermal-Hydraulic Results with Break Flow Flashing Fraction for the Farley RSG Radiological Dose Analysis with Additional 10 Percent Mass Flowrate	
Reactor Trip, SI Actuation, and Loss Of Offsite Power	224.2 seconds[1]
Pre-Trip (less than 224.2 seconds)	
Tube Rupture Break Flow	21,600 lbm
Percentage of Break Flow That Flashes	20.79%
Steam Release Rate to Condenser	3400 lbm/sec for all SGs or 1133.3 lbm/sec for single SG
Post Trip (after 224.2 seconds)	
Tube Rupture Break Flow	136,400 lbm
Percentage of Break Flow That Flashes	15.07%
Steam Release from Ruptured SG up to 2 Hours	79,000 lbm
Steam Release from Intact SGs up to 2 Hours	422,000 lbm
Feedwater Flow to Intact SGs up to 2 Hours	327,000 lbm
Steam Release from Intact SGs for 2 - 8 Hours	934,000 lbm
Feedwater Flow to Intact SGs for 2 - 8 Hours	981,000 lbm
Initial Ruptured SG Water Mass Maximum Minimum	 107,942 lbm 104,193 lbm
Final Ruptured SG Water Mass	101,955 lbm

Notes:

(1) Assumes nominal Technical Specification SI Setpoint. To reach Safety Analysis Limit setpoint of 1700 psia an additional 100 seconds should be assumed. This may be conservative for determining when the control room emergency heating, ventilation, and air conditioning will actuate.

4.4 LOCA MASS AND ENERGY RELEASES

The uncontrolled release of pressurized high temperature reactor coolant, termed a LOCA, will result in release of steam and water into the containment. This, in turn, will result in increases in the local subcompartment pressures, and an increase in the global containment pressure and temperature. Therefore, there are both long- and short-term issues reviewed relative to a postulated LOCA that must be considered at the conditions for Farley Units 1 and 2 with Model 54F steam generators.

The long-term LOCA mass and energy (M&E) releases are analyzed to approximately 10^6 seconds and are utilized as input to the containment integrity analysis, which demonstrates the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical LBLOCA. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure and to limit the temperature excursion to less than the Environmental Qualification (EQ) acceptance limits. For this program, Westinghouse generated the M&E releases using the March 1979 model, described in Reference 1. The NRC review and approval letter is included with Reference 1. This methodology has been approved for Farley Units 1 and 2 for the Power Uprate Project. Section 4.4.1 discusses the long-term LOCA M&E releases generated for this program. The results of this analysis were provided for use in the containment integrity analysis and EQ reviews (see BOP Licensing Report).

4.4.1 Long-Term LOCA M&E Releases

The M&E release rates described in this section form the basis of further computations by SCS to evaluate the containment following the postulated accident. Discussed in this section are the long-term LOCA M&E releases for the hypothetical double-ended pump suction (DEPS) rupture and double-ended hot leg (DEHL) rupture break cases.

4.4.1.1 Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the RCS operating temperatures are chosen to bound the highest average coolant temperature range of all operating cases (including the uncertainties associated with the RCS flow of -2.4 percent), and a temperature uncertainty allowance of (+6.0°F) is then added. Nominal parameters are used in certain instances. For example, the RCS pressure in this analysis is based on a nominal value of 2250 psia plus an uncertainty allowance (+50 psi). All input parameters are chosen consistent with accepted analysis methodology.

Some of the most critical items are the RCS initial conditions, core decay heat, SI flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed next. Table 4.4.1-1 presents key data assumed in the analysis.

The core rated power of 2775 MWt adjusted for calorimetric error (+2 percent of power) was used in the analysis. As previously noted, the use of RCS operating temperatures to bound the highest average coolant temperature range are used as bounding analysis conditions. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures that are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and deadband is reflected in the initial RCS temperatures. The selection of 2250 psia as the limiting pressure is considered to effect the blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature) and, subsequently, has a higher RCS mass available for releases. Thus, 2250 psia plus uncertainty is selected for the initial pressure as the limiting case for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (i.e., to maximize the core stored energy). The margin in core stored energy is chosen to be +15 percent to address fuel densification and the thermal fuel model with its associated uncertainties. Thus, the analysis very conservatively accounts for the stored energy in the core.

A margin in RCS volume of 3 percent (which is composed of a 1.6-percent allowance for thermal expansion and 1.4 percent for uncertainty) is modeled.

A uniform steam generator tube plugging level of 0 percent is modeled. This assumption maximizes the reactor coolant volume and fluid release by virtue of consideration of the RCS fluid in all steam generator tubes. During the post-blowdown period, the steam generators are active heat sources since significant energy remains in the secondary-side metal and secondary-side mass that has the potential to be transferred to the primary side. The 0 percent tube plugging assumption maximizes heat transfer area and, therefore, the transfer of secondary-side heat across the steam generator tubes. Additionally, this assumption reduces the reactor coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow. Thus, the analysis conservatively accounts for the level of steam generator tube plugging.

The secondary-to-primary heat transfer is maximized by assuming conservative heat transfer coefficients. This conservative energy transfer is ensured by maximizing the initial internal energy of the inventory in the steam generator secondary side. This internal energy is based on full power operation plus uncertainties.

Regarding SI flow, the M&E release calculation considers configurations/failures to conservatively bound respective alignments. The cases include: (a) a Minimum Safeguards case (one CHG/SI and one LHSI Pump); and (b) a Maximum Safeguards case, (two CHG/SI and two LHSI Pumps). In addition, the containment backpressure is assumed to be equal to the containment design pressure. This assumption is shown in Reference 1 to be conservative for the generation of M&E releases.

In summary, the following assumptions were employed to ensure that the M&E releases are conservatively calculated, thereby maximizing energy release to containment.

1. Maximum expected operating temperature of the RCS (100 percent full power conditions)

2. Allowance for RCS temperature uncertainty (+6.0°F)

3. Margin in RCS volume of 3 percent (which is composed of a 1.6-percent allowance for thermal expansion, and 1.4 percent for uncertainty)

4. Core rated power of 2775 MWt

5. Allowance for calorimetric error (+2 percent of power)

6. Conservative heat transfer coefficients (i.e., steam generator primary/secondary heat transfer and RCS metal heat transfer)

7. Allowance in core stored energy for effect of fuel densification

8. A margin in core stored energy (+15 percent to account for manufacturing tolerances)

9. An allowance for RCS initial pressure uncertainty (+50 psi)

10. A maximum containment backpressure equal to design pressure (54 psig)

11. Allowance for RCS flow uncertainty (-2.4 percent)

12. Steam generator tube plugging level (0 percent uniform):

    a. Maximizes reactor coolant volume and fluid release

    b. Maximizes heat transfer area across the steam generator tubes

    c. Reduces coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow

Additionally, there are some differences between Unit 1 and Unit 2. Unit 1 is an upflow design, whereas Unit 2 is downflow. Separate models were generated for both units and are used for the calculations. The releases for both units are provided herein.

Thus, based on the previously discussed conditions and assumptions, an analysis of Farley Units 1 and 2 was made for the release of M&E from the RCS in the event of a LOCA at 2775 MWt.

4.4.1.2 Description of Analyses

The evaluation model used for the long-term LOCA M&E release calculations is the March 1979 model described in Reference 1. This evaluation model has been reviewed and approved for Farley Units 1 and 2 by the NRC for the Power Uprate Project.

This section presents the long-term LOCA M&E releases generated in support of the Farley Units 1 and 2 RSG Program. These M&E releases are then subsequently used in the containment integrity analysis (see BOP Licensing Report).

4.4.1.3 LOCA M&E Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA M&E analysis, is typically divided into four phases.

1. Blowdown – the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.

2. Refill – the period of time when the lower plenum is being filled by accumulator and ECCS water. At the end of blowdown, a large amount of water remains in the cold legs, DC, and lower plenum. To conservatively consider the refill period for the purpose of containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment. Thus, the refill period is conservatively neglected in the M&E release calculation.

3. Reflood – begins when the water from the lower plenum enters the core and ends when the core is completely quenched.

4. Post-reflood (FROTH) – describes the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the steam generators prior to exiting the break as steam. After the broken loop steam generator cools, the break flow becomes two-phase.

4.4.1.4 Computer Codes

The Reference 1 M&E release evaluation model is comprised of M&E release versions of the following codes: SATAN VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA M&E releases for Farley Units 1 and 2.

SATAN VI calculates blowdown, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flowrates, and energy transfer between primary and secondary sides as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the ECCS refills the reactor vessel and provides cooling to the core. The most important feature of WREFLOOD is the steam/water mixing model (see Subsection 4.4.1.8.2).

FROTH models the post-reflood portion of the transient. The FROTH code is used for the steam generator heat addition calculation from the broken and intact loop steam generators.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

4.4.1.5 Break Size and Location

Generic studies have been performed with respect to the effect of postulated break size on the LOCA M&E releases. The double-ended guillotine break has been found to be limiting due to larger mass flowrates during the blowdown phase of the transient. During the reflood and FROTH phases, the break size has little effect on the releases.

Three distinct locations in the RCS loop can be postulated for pipe rupture for any release purposes:

1. Hot leg (between vessel and steam generator)
2. Cold leg (between pump and vessel)
3. Pump suction (between steam generator and pump)

The break locations analyzed for this program are the DEPS rupture (10.48 ft^2) and DEHL rupture (9.54 ft^2). Break M&E releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown. The following information provides a discussion on each break location.

The DEHL rupture has been shown in previous studies to result in the highest blowdown M&E release rates. Although the core flooding rate would be the highest for this break location, the amount of energy released from the steam generator secondary side is minimal because the majority of the fluid that exits the core, vents directly to containment bypassing the steam generators. As a result, the reflood M&E releases are reduced significantly as compared to either the pump suction or cold leg break locations where the core exit mixture must pass through the steam generators before venting through the break. For the hot leg break, generic studies have confirmed that there is no reflood peak (i.e., from the end of the blowdown period the containment pressure would continually decrease). Therefore, only the M&E releases for the hot leg break blowdown phase are calculated and presented in this section of the report.

The cold leg break location has also been found in previous studies to be much less limiting in terms of the overall containment energy releases. The cold leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold leg break is bounded by other breaks and no further evaluation is necessary.

The pump suction break combines the effects of the relatively high core flooding rate, as in the hot leg break, and the addition of the stored energy in the steam generators. As a result, the pump suction break yields the highest energy flowrates during the post-blowdown period by including all of the available energy of the RCS in calculating the releases to containment.

4.4.1.6 Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost. This results in the actuation of the emergency diesel generators, required to power the SIS. This is not an issue for the blowdown period, which is limited by the DEHL break.

Two cases have been analyzed to assess the effects of a single failure. The first case assumes minimum safeguards SI flow based on the postulated single failure of an emergency diesel generator. This results in the loss of one train of safeguards equipment. The other case assumes maximum safeguards SI flow based on no postulated failures that would impact the amount of ECCS flow. The analysis of the cases described provides confidence that the effect of credible single failures is bounded.

4.4.1.7 Acceptance Criteria for Analyses

A LBLOCA is classified as an ANS Condition IV event, an infrequent fault. To satisfy the NRC acceptance criteria presented in the Standard Review Plan Section 4.2.1.3, the relevant requirements are as follows:

1. 10 CFR 50, Appendix A
2. 10 CFR 50, Appendix K, paragraph I.A

To meet these requirements, the following must be addressed:

1. Sources of energy
2. Break size and location
3. Calculation of each phase of the accident

4.4.1.8 M&E Release Data

4.4.1.8.1 Blowdown M&E Release Data

The SATAN-VI code is used for computing the blowdown transient. The code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermodynamic equilibrium is assumed in each element. A point kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in Reference 1.

4.4.1.8.2 Reflood M&E Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models – one for the contents of the reactor vessel and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the DC. Additional transient phenomena, such as pumped SI and accumulators, reactor coolant pump performance, and steam generator release are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters such as core flooding rate, core and DC water levels, fluid thermodynamic conditions (pressure, enthalpy, density) throughout the primary side, and mass flowrates through the primary side. The code permits hydraulic modeling of the two flowpaths available for discharging steam and entrained water from the core to the break, i.e., the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the use and application of the Reference 1 M&E release evaluation model in recent analyses, e.g., D. C. Cook Docket (Reference 2). Even though the Reference 1 model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 2). Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (i.e., thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with condensation of steam by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that need be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data has been reviewed for validation of the containment integrity reflood steam/water mixing model. This data was generated in 1/3-scale tests (Reference 3), which are the largest scale data available and thus most clearly simulates the flow regimes and gravitational effects that would occur in a PWR. These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale tests corresponds directly to containment integrity reflood conditions. The injection flowrates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in Reference 1. For all of these tests, the data clearly indicates the occurrence of very effective mixing with rapiu steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the pump suction double-ended rupture break. For this break, there are two flowpaths available in the RCS by which M&E may be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the reactor coolant pump. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the DC and through the broken loop cold leg and pump in venting to containment. This steam also encounters ECCS injection water as it passes through the broken loop cold leg, complete mixing occurs and a portion of it is condensed. It is this portion of steam which is condensed that is assumed in this analysis. This assumption is justified based upon the postulated break location, and the actual physical presence of the ECCS injection nozzle. A description of the test and test results are contained in References 1 and 3.

4.4.1.8.3 Post-Reflood M&E Release Data

The FROTH code (Reference 4) is used for computing the post-reflood transient. The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the steam generator tubes. The M&E releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken loop and intact loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure, but the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase fluid exits the core, flows through the hot legs, and becomes superheated as it passes through the steam generator. Once the broken loop cools, the break flow becomes two phase. During the FROTH calculation, ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure, after this point the EPITOME code completes the steam generator depressurization (see Subsection 4.4.1.8.5 for additional information).

The methodology for the use of this model is described in Reference 1. The M&E release rates are calculated by FROTH and EPITOME until the time of containment depressurization. Aft containment depressurization (14.7 psia), the M&E release available to containment is generated directly from core boiloff/decay heat.

4.4.1.8.4 Decay Heat Model

On November 2, 1978, the Nuclear Power Plant Standards Committee of the ANS approved ANS Standard 5.1 (Reference 5) for the determination of decay heat. This standard was used in the M&E release model for Farley Nuclear Plant Units 1 and 2.

Significant assumptions in the generation of the decay heat curve for use in the LOCA M&E releases analysis include the following:

1. Decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.

2. Decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.

3. Fission rate is constant over the operating history of maximum power level.

4. The factor accounting for neutron capture in fission products has been taken from Table 10 of Reference 5.

5. The fuel has been assumed to be at full power for 10^8 seconds.

6. The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.

7. Two sigma uncertainty (two times the standard deviation) has been applied to the fission product decay.

Based upon NRC staff review, SER of the March 1979 evaluation model (Reference 1), use of the ANS Standard-5.1, November 1979 decay heat model was approved for the calculation of M&E releases to the containment following a LOCA.

4.4.1.8.5 Steam Generator Equilibration and Depressurization

Steam generator equilibration and depressurization is the process by which secondary-side energy is removed from the steam generators in stages. The FROTH computer code calculates the heat removal from the secondary-side mass until the secondary-side temperature is T_{sat} at the containment design pressure. After the FROTH calculations, the EPITOME code continues the FROTH calculation for steam generator cooldown removing steam generator secondary-side energy at different rates (i.e., first and second stage rates). The first stage rate is applied until the steam generator reaches T_{sat} at the user-specified intermediate equilibration pressure, when the secondary-side pressure is assumed to reach the actual containment pressure. Then, the second stage rate is used until the final depressurization, when the secondary-side reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken loop and intact loop steam generators are calculated separately.

During the FROTH calculations, steam generator heat removal rates are calculated using the secondary-side temperature, primary-side temperature, and a secondary-side heat transfer coefficient determined using a modified McAdam's correlation. Steam generator energy is removed during the FROTH transient until the secondary-side temperature reaches saturation temperature at the containment design pressure. The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The steam generator energy available to be released during the first stage interval is determined by calculating the difference in secondary energy available at the containment design pressure and that at the (lower) user-specified intermediate equilibration pressure, assuming saturated conditions. This energy is then divided by the first stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second stage rate. The second stage rate is determined as the fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user-specified time of the final depressurization at 212°F. With current methodology, all of the secondary-side energy remaining after the intermediate equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization down to atmospheric pressure at 3600 seconds, i.e., 14.7 psia and 212°F.

4.4.1.8.6 Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are the RCS, accumulators, and pumped SI.

The energy sources considered in the LOCA M&E release analysis are listed below.

1. RCS water
2. Accumulator water (all three inject)
3. Pumped safety injection water
4. Decay heat
5. Core stored energy
6. RCS metal (includes steam generator tubes)
7. Steam generator metal (includes transition cone, shell, wrapper, and other internals)

8. Steam generator secondary-side energy (includes fluid mass and steam mass)
9. Secondary-side transfer of energy (feedwater into and steam out of the steam generator secondary side)

The energy reference points are as follows.

1.	Available energy:	212°F; 14.7 psia
2.	Total energy content:	32°F; 14.7 psia

The M&E inventories are presented at the following times, as appropriate.

1. Time zero (initial conditions)
2. End of blowdown time
3. End of refill time
4. End of reflood time
5. Time of broken loop steam generator equilibration to pressure setpoint
6. Time of intact loop steam generator equilibration to pressure setpoint
7. Time of full depressurization (3600 seconds)

In the M&E release data presented, no Zirc-water reaction heat was considered because the clad temperature is assumed not to rise high enough for the rate of the Zirc-water reaction heat to be of any significance.

4.4.1.8.7 Effect of RHR Interruption on Post-Reflood M&E Releases

The Farley Units 1 and 2 procedures specify that the RHR pumps are stopped and restarted during the cold leg switchover process. This assumption effects the post-reflood transient results. A discussion of the minimum and maximum safeguards cases is provided below.

Minimum Safeguards (one RHR and one CH/SI pump running)

It is assumed that the RHR pump is stopped at the time when the RWST low-level alarm is reached (assuming the earliest possible shutdown of the RHR pump is conservative). It is assumed that the CHG/SI pump is not stopped and continues to take suction from the RWST until the RHR pump is restarted, at which time it is assumed that the CHG/SI pump is realigned to the outlet of the RHR pump and delivers flow at the sump temperature (assuming the earliest possible delivery of water from the sump is conservative relative to ECCS flow temperature). Note: Realignment does not require that the CHG/SI pump be stopped. The analysis assumes that the RHR pump is stopped at the time of switchover at 2139.0 seconds and is restarted at 180 seconds after the time of switchover at 2319.0 seconds.

Maximum Safeguards (two RHR and two CHG/SI pumps running)

It is assumed that the two RHR pumps are stopped at the time when the low-level alarm is reached (assuming the earliest possible shutdown of the RHR pumps is conservative). It is assumed that the CHG/SI pumps are not stopped and continue to take suction from the RWST until the second RHR pump is restarted, at which time it is assumed that the CHG/SI pumps are realigned to the outlet of the RHR pumps and deliver flow at the sump temperature (assuming the earliest possible delivery of water from the sump is conservative relative to ECCS flow temperature). The analysis assumes that both RHR pumps are stopped at the time of switchover at 1311.6 seconds and that both are restarted at 180 seconds after the initiation of the switchover sequence at 1491.6 seconds. Note: Realignment does not require that the CHG/SI pump be stopped.

4.4.1.8.8 Conclusions

The consideration of the various energy sources in the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. Thus, the review guidelines presented in Standard Review Plan Section 4.2.1.3 have been satisfied. The results of this analysis were provided for use in the containment integrity analysis (see BOP Licensing Report).

4.4.1.8.9 References

1. *Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version*, WCAP-10325-P-A (Proprietary) and WCAP-10326-A (Non-Proprietary), May 1983

2. *Amendment No. 126, Facility Operating License No. DPR-58 (TAC No. 7106), for D. C. Cook Nuclear Plant Unit 1*, Docket No. 50-315, June 9, 1989

3. *Mixing of Emergency Core Cooling Water with Steam; 1/3-Scale Test and Summary*, Final Report, WCAP-8423 (Non-Proprietary), EPRI 294-2, June 1975

4. *Westinghouse Mass and Energy Release Data For Containment Design*, WCAP-8264-P-A, Rev. 1 (Proprietary) and WCAP-8312-A (Non-Proprietary), August 1975

5. *American National Standard for Decay Heat Power in Light Water Reactors*, ANSI/ANS-5.1 1979, August 1979

Table 4.4.1-1 System Parameters Initial Conditions for RSG	
Parameters	**Value**
Core Thermal Power (MWt)(1)	2830.5
Reactor Coolant System Total Flowrate (lbm/sec)(1)	27250.0
Vessel Outlet Temperature (°F)(1)	619.3
Core Inlet Temperature (°F)(1)	547.1
Vessel Average Temperature (°F)(1)	583.2
Initial Steam Generator Steam Pressure (psia)	817
Steam Generator Design	Model 54F
Steam Generator Tube Plugging (%)	0
Initial Steam Generator Secondary-Side Fluid Mass (lbm)(1)	121826.1
Assumed Maximum Containment Backpressure (psia)	68.7
Accumulator	
Water Volume (ft^3) per accumulator	1040
N_2 Cover Gas Pressure (psia)	600
Temperature (°F)	120
Safety Injection Delay, total (sec) (from beginning of event)	30.9

Notes:

(1) Core Thermal Power, RCS Total Flowrate, RCS Coolant Temperatures, and Steam Generator Secondary-Side Fluid Mass include appropriate uncertainty and/or allowance.

4.5 MAIN STEAMLINE BREAK M&E RELEASES

4.5.1 Main Steamline Break M&E Releases Inside Containment

4.5.1.1 Identification of Causes and Accident Description

Steamline ruptures occurring inside a reactor containment structure may result in significant releases of high-energy fluid to the containment environment, possibly resulting in high containment temperatures and pressures. The quantitative nature of the releases following a steamline rupture is dependent upon the plant operating conditions and the size of the rupture, as well as the configuration of the plant steam system and the containment design. The analysis considers a variety of postulated pipe breaks encompassing wide variations in plant operation, safety system performance, and break size in determining the main steamline break (MSLB) M&E releases for use in containment integrity analysis.

4.5.1.2 Input Parameters and Assumptions

The postulated break area can have competing effects on blowdown results. Larger break areas will be more likely to result in large amounts of water being entrained in the blowdown. However, larger breaks also result in earlier generation of protective trip signals following the break and a reduction of both the power production by the plant and the amount of high-energy fluid available to be released to the containment.

To determine the effects of plant power level and break area on the M&E releases from a ruptured steamline, spectra of both variables have been evaluated. At plant power levels of 102 percent, 70 percent, 30 percent and 0 percent of nominal full-load power, four break sizes have been defined. These break areas are defined below.

1. A full double-ended rupture (DER) downstream of the flow restrictor in one steamline (Note that a DER is defined as a rupture in which the steam pipe is completely severed and the ends of the break displace from each other.)

2. A small break at the steam generator nozzle having an area just larger than that at which water entrainment occurs

3. A small break at the steam generator nozzle having an area just smaller than that at which water entrainment occurs

4. A small split rupture that will neither generate a steamline isolation signal from the ESF nor result in water entrainment in the break effluent

Five cases were chosen for the RSG analysis based on the results of the analyses presented in the power uprate analysis. Each of these cases was analyzed with the RSG condition assuming isolation is accomplished by the redundant swing-disc isolation valves in each intact steamline. These five cases, of the 16 included in the power uprate analysis, represent the most limiting cases with respect to peak containment pressure and temperature. The similarities between

Model 51 and Model 54F, as described in Section 2.0, supports this assumption. The important plant conditions and features that were assumed are discussed in the following paragraphs.

INITIAL POWER LEVEL

Steamline breaks can be postulated to occur with the plant in any operating condition ranging from hot shutdown to full power. Since steam generator mass decreases with increasing power level, breaks occurring at lower power levels will generally result in a greater total mass release to the containment. However, because of increased stored energy in the primary side of the plant, increased heat transfer in the steam generators, and additional energy generation in the fuel, the energy release to the containment from breaks postulated to occur during full-power, or near full-power, operation may be greater than for breaks occurring with the plant in a low-power, or hot-shutdown, condition. Additionally, steam pressure and the dynamic conditions in the steam generators change with increasing power and have a significant influence on both the rate of blowdown and the amount of moisture entrained in the fluid leaving the break.

Because of the opposing effects (mass versus energy release) of changing power level on steamline break releases, no single power level can be singled out as a worst case initial condition for a steamline break event. Therefore, several different power levels spanning from full- to zero-power conditions have been investigated for Farley Units 1 and 2, as presented in the Farley FSAR, based on the information in Reference 1. For this RSG analysis, the power levels and steamline break sizes are noted in Section 4.5.1.3 of this report.

In general, the plant initial conditions are assumed to be at the nominal value corresponding to the initial power for that case, with appropriate uncertainties included. Tables 4.5-1 and 4.5-2 identify the values assumed for RCS pressure, RCS vessel average temperature, pressurizer water volume, steam generator water level, and feedwater enthalpy corresponding to each power level analyzed.

SINGLE-FAILURE ASSUMPTIONS

Each case analyzed considers a single failure. One of these failures results in minimum containment spray and fan coolers to allow for a failure of a train of containment safeguards features. The method of determining the steam system blowdown, used in conjunction with the minimum containment safeguards, assumes no failure in steam or feedwater isolation.

The following single failures are postulated (discussed also in Reference 1) that may significantly affect the containment results:

a. Failure to Completely Isolate All the Main Steamlines

   The main steamline isolation function is accomplished via two redundant swing-disc isolation valves in each of the three steamlines. Both valves close on an isolation signal to terminate steam flow from the associated steam generator. A single failure in one of the two valves has no effect for a main steamline rupture downstream of the valves since the isolation function will be performed by the other valve in the same steamline. However, a main steamline rupture upstream of these valves, as postulated for the inside-containment analysis, will create a situation in which the steam generator on the faulted loop cannot be isolated. The contents of this steam generator and any feedwater flow to it will blowdown continually until the feedwater flow is terminated and the contents of the steam generator are emptied. Since these valves stop steam flow only in the forward direction, the M&E release to containment is modified to include the entire steam piping volume downstream of the isolation valves for the other two steam generators, including the steamline header and steam dump piping. The intent of this assumption is to show that the protection logic, which provides a signal to close the isolation valves, and the associated delay time, are adequate to limit the amount of steam M&E discharged into containment such that the containment pressure limit is not exceeded.

b. Failure of the Flow Control Valve (FCV) in the Faulted Loop

If the flow control valve (FCV) in the feedwater line to the faulted steam generator is assumed to fail in the open position, main feedwater flow would continue from the condensate and feedwater system until backup isolation is provided via the main feedwater isolation valve (MFIV) closure. This additional inventory would then be available to be released to containment.

c. Emergency Diesel Generator

When offsite power is lost, the emergency diesel generators (EDGs) are relied upon to supply emergency power to the safeguards equipment. The single failure associated with one diesel generator failing to start causes power to be lost to one train of SI, and one train of the containment safeguards functions. The effects of a loss of offsite power and this single failure are a longer delay until SI actuation and loss of forced convection heat transfer on the primary side of the steam generators. Minimum SI flow is assumed for all cases. The effect of reduced containment safeguards is accounted for in the containment response analysis.

The assumption of a trip of all the RCPs coincident with reactor trip is less limiting than with offsite power available since the M&E releases are reduced due to the loss of forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

MAIN FEEDWATER SYSTEM

The rapid depressurization that occurs following a steamline rupture typically results in large amounts of water being added to the steam generators through the main feedwater system. Rapid-closing FCVs in the main feedwater lines limit this effect. The feedwater addition, which occurs prior to closing the feedwater line control valves, influences the steam generator blowdown in several ways. First, the rapid addition increases the amount of entrained water in large break cases by lowering the bulk quality of the steam exiting the rupture. Second, because the water entering the steam generator is subcooled, it lowers the steam pressure, thereby reducing the flowrate out of the break. As the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the control valves will flash into the steam generators, providing additional secondary fluid that may exit out of the rupture. Finally, the increased flow causes an increase in the heat transfer rate from the primary to secondary sides, resulting in greater energy being released out of the break. Since these are competing effects on the total M&E release, no "worst case" feedwater transient can be defined for all plant conditions.

Main feedwater flow was conservatively modeled by assuming that sufficient feedwater flow was provided to match the steam flow prior to reactor trip. The initial increase in feedwater flow (until fully isolated) is in response to increases in steam flow following initiation of the steamline break. This maximizes the total mass addition prior to feedwater isolation. The feedwater isolation response time, following the SI signal, is assumed to be a total of 7 seconds, consisting of 2 seconds for signal processing plus 5 seconds for the feedwater FCV stroke time.

Following feedwater isolation, as the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the isolation valve may flash to steam if the feedwater temperature exceeds the saturation pressure. This unisolable feedwater line volume is an additional source of high-energy fluid that is assumed to be discharged out of the break. The unisolable volume in the feedwater lines is maximized for the faulted loop and minimized for the intact loops. The energy in the unisolable volume is maximized by assuming recirculated feedwater from the condenser rather than "cold" water from the condensate storage tank.

AUXILIARY FEEDWATER SYSTEM

Generally, within the first minute following a steamline break, the AFWS is initiated on any one of several protection system signals. Addition of AFW to the steam generators increases the secondary-side mass available to cover the tube bundle and reduces the amount of superheated steam produced. The AFW flow to the faulted and intact steam generators is a function of the backpressure in the steam generators. A higher AFW flowrate to the faulted loop steam generator is conservative for the steamline break event; therefore, these flows were maximized as a function of backpressure. Conversely, a lower AFW flowrate is conservative for the intact loop steam generators; thus, these flows were minimized as a function of backpressure.

STEAM GENERATOR REVERSE HEAT TRANSFER

Once the steamline isolation is complete, the steam generators in the intact loops become sources of energy that can be transferred to the steam generator with the broken line. This energy transfer occurs via the primary coolant. As the primary plant cools, the temperature of the coolant flowing in the steam generator tubes drops below the temperature of the secondary fluid in the intact steam generators, resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steamline. The effects of reverse steam generator heat transfer are included in the results.

STEAM GENERATOR FLUID MASS

A maximum initial steam generator mass in the faulted loop steam generator is used in all of the analyzed cases. The use of a high faulted-loop initial steam generator mass maximizes the steam generator inventory available for release to containment. The initial mass is calculated as the value corresponding to the programmed level +9 percent NRS for the at-power cases and +7 percent NRS for the 0 percent power case. Minimum initial masses in the intact loop steam generators are used in all of the analyzed cases. The use of reduced initial steam generator masses minimizes the availability of the heat sink afforded by the steam generators on the intact loops. The initial masses are calculated as the value corresponding to the programmed level -7 percent NRS. All steam generator fluid masses are calculated assuming 0 percent tube plugging. This assumption is conservative with respect to the RCS cooldown through the faulted loop steam generator resulting from the steamline break. A mass uncertainty is applied to both the faulted and intact steam generators and is in addition to the programmed +9/-7 percent (+7/-7 percent for 0 percent power) NRS level of uncertainty previously mentioned.

WATER ENTRAINMENT IN THE BREAK EFFLUENT

Saturated steam (a steam quality of 1.0) is assumed for all break sizes at all power levels since entrainment data is not available for the Model 54F steam generator design. The M&E releases have been determined using the conservative assumption of no entrainment during the early part of the releases.

MAIN STEAMLINE ISOLATION

Steamline isolation is assumed in the two intact loops to terminate the blowdown from those steam generators. A delay time of 12 seconds is assumed (2 second signal processing time plus 10 second valve stroke time) with full steam flow assumed through the valve during the valve stroke. The assumption of unrestricted steam flow from the intact steam generators for this time conservatively accounts for the effects of the unisolable steamline volume that would be released following closure of the two redundant swing-disc isolation valves in each steamline. The assumption of unrestricted steam flow from the intact steam generators for this time conservatively accounts for the effects of the steam mass in the isolable volume that would be released prior to the closure of the isolation valve in the steamline with the pipe break. Isolation of the steam generator in the faulted loop is not assumed so as to simulate the steamline rupture upstream of the isolation valves (between the valves and the steam generator).

BREAK FLOW MODEL

Piping discharge resistances are not included in the calculation of the releases resulting from the steamline ruptures [Moody Curve for an f(L/D) = 0 is used].

STEAMLINE VOLUME BLOWDOWN

The contribution to the M&E releases from the secondary plant steam piping is included in the M&E release calculations. The flowrate is determined using the Moody correlation, the pipe cross-sectional area, and the initial steam pressure. For all steamline break cases analyzed for the RSG, the unisolable steamline mass is included in the mass exiting the break from the time of steamline isolation until the unisolable mass is completely released to containment. The steam piping volume assumed in the analysis is 3475.0 ft^3.

SAFETY INJECTION SYSTEM

Minimum SIS flowrates corresponding to the failure of one SIS train are assumed in this analysis. A minimum SIS flow is conservative since the reduced boron addition maximizes a return to power resulting from the RCS cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break. The delay time to achieve full SIS flow is assumed to be 27 seconds for this analysis with offsite power available.

REACTOR COOLANT SYSTEM METAL HEAT CAPACITY

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, and the reactor coolant pumps. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. Stored metal heat does not have a major impact on the calculated M&E releases. The effects of this RCS metal heat are included in the results using conservative thick metal masses and heat transfer coefficients.

PROTECTION SYSTEM ACTUATIONS

The protection systems available to mitigate the effects of a MSLB accident inside containment include reactor trip, safety injection, steamline isolation, and feedwater isolation. Analyses of the containment responses to the MSLB, which model the operation of the emergency fan coolers and containment spray, are contained in the BOP Licensing Report. The protection system actuation signals and associated setpoints that were modeled in the analysis are identified in Table 4.5-3. The setpoints used are conservative values with respect to the Farley plant-specific values delineated in the Technical Specifications.

For the 1.069 ft^2 DER MSLB at all power levels and the smaller breaks at powers of 102 percent, 70 percent, and 30 percent, the first protection system signal actuated is low steamline pressure (lead/lag compensated in each channel) in two loops, which initiates steamline isolation and safety injection; the SI signal produces a reactor trip signal. Feedwater system isolation occurs as a result of the SI signal.

For the split-rupture steamline breaks at all power levels, no mitigation signals are received from either the reactor protection system (RPS) or the engineered safety features actuation system (ESFAS). The first protection system signal actuated is high containment pressure (2-out-of-3 channels), which initiates SI, the SI signal produces a reactor trip signal. Feedwater system isolation occurs as a result of the SI signal. The second protection system signal actuated is high-high containment pressure (2-out-of-3 channels), which actuates steamline isolation.

The time of receipt of the high containment pressure signal is determined based on preliminary cases for the MSLB transient analysis, in which no protection functions are assumed, and preliminary results of the containment pressure response. The calculated time for the high containment pressure signal is then used to actuate a reactor trip, feedwater isolation, and SI (with the applicable delays) for subsequent cases of the MSLB event. In these latter cases, the time of receipt of the high-high containment pressure is again estimated from preliminary containment pressure analysis. The containment pressure analysis assumes a conservative time for steamline isolation (following a high-high containment pressure signal) for the final containment pressure/temperature response.

ROD CONTROL

The rod control system is conservatively assumed to be in manual operation for all steamline break analyses.

CORE DECAY HEAT

Core decay heat generation assumed in calculating the steamline break M&E releases is based on the 1979 ANS Decay Heat + 2σ model (Reference 2).

CORE REACTIVITY COEFFICIENTS

Conservative core reactivity coefficients corresponding to EOC conditions, including hot zero power (HZP) stuck-rod core design parameters, are used to maximize the reactivity feedback effects resulting from the steamline break. Use of maximum reactivity feedback results in higher power generation if the reactor returns to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

4.5.1.3 Description of Analysis

The break flows and enthalpies of the steam release through the steamline break inside containment are analyzed with the RETRAN computer code (Reference 3). Blowdown M&E releases determined using RETRAN include the effects of core power generation, main and auxiliary feedwater additions, engineered safeguards systems, RCS thick metal heat storage, and reverse steam generator heat transfer.

The Farley NSSS is analyzed using RETRAN to determine the transient steam M&E releases inside containment following a steamline break event. The tables of M&E releases are used as input conditions to the analysis of the containment response.

Based on the results of the MSLB M&E releases and the associated containment response analyses documented for the Farley Power Uprate Project, only the limiting cases with respect to containment pressure or temperature are included in the analysis for the steam generator replacement. Analyses of the limiting steamline breaks have been completed for the Farley RSGs using RETRAN. An assessment of the containment pressure and temperature results for the RSG Program reveals that the most limiting steamline breaks from the Power Uprate Project remain the most limiting for the Farley RSGs. The RSG results with RETRAN also show similar results to the power uprate analysis with LOFTRAN. The following five licensing-basis cases of the MSLB inside containment were analyzed with the RSG assumptions: (The case numbers correspond to those in the Power Uprate Project Engineering Report.)

- Case 1: Full double-ended (1.069 ft^2) rupture at 102 percent power
- Case 8: 0.47 ft^2 split rupture at 70 percent power
- Case 9: Full double-ended (1.069 ft^2) rupture at 30 percent power
- Case 12: 0.60 ft^2 split rupture at 30 percent power
- Case 13: Full double-ended (1.069 ft^2) rupture at hot standby (0 percent power)

4.5.1.4 Acceptance Criteria

The MSLB is classified as an American Nuclear Society (ANS) Condition IV event, an infrequent fault. Additional clarification of the ANS classification of this event is presented in Section 4.2.4 of this report, which discusses the core response to a steamline break event. The acceptance criteria associated with the steamline break event resulting in a M&E release inside containment is based on an analysis that provides sufficient conservatism to ensure that the containment design margin is maintained. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, the break flow model including entrainment, main and auxiliary feedwater flow, steamline and feedwater isolation, and single failure such that the containment peak pressure and temperature are maximized. These analysis assumptions have been included in this steamline break M&E release analysis, as discussed in Reference 1 and Section 4.5.1.2 of this report. The tables of M&E release data for each of the steamline break cases noted in the previous section are used as input to a containment response calculation to confirm the design parameters of the Farley Units 1 and 2 containment structure.

4.5.1.5 Results

Using Reference 1 and the Power Uprate Project NSSS Licensing Report (WCAP-14723) as bases, including parameter changes associated with the RSGs, the M&E release rates for each of the steamline break cases noted in Section 4.5.1.3 were developed for use in containment pressure and temperature response analyses. Tables 4.5-4 and 4.5-5 provide the sequence of events for the two limiting steamline breaks (Case 1 (i.e., peak temperature case) and Case 13 (i.e., peak pressure case)) inside containment.

4.5.1.6 Conclusions

The M&E releases from the five steamline break cases have been analyzed with the assumptions of RSGs. The assumptions delineated in Section 4.5.1.2 have been included in the steamline break analysis such that the applicable acceptance criteria are met. The steam M&E releases discussed in this section have been provided for use in the containment response analysis in support of the Farley RSG Program (see BOP Licensing Report).

4.5.2 Main Steamline Break M&E Releases Outside Containment

4.5.2.1 Identification of Causes and Accident Description

Steamline ruptures occurring outside the reactor containment structure may result in significant releases of high-energy fluid to the structures surrounding the steam systems. Superheated steam blowdowns following the steamline break have the potential to raise compartment temperatures outside containment. The impact of the steam releases depends on the plant configuration at the time of the break, the plant response to the break, and the size and location of the break. Because of the interrelationship among many of the factors that influence steamline break M&E releases, an appropriate determination of a single limiting case with respect to M&E releases cannot be made. Therefore, it is necessary to analyze the steamline break event outside containment for a range of conditions.

4.5.2.2 Input Parameters and Assumptions

To determine the effects of plant power level and break area on the M&E releases from a ruptured steamline, spectra of both variables have been evaluated (Reference 4). At plant power levels of 102 percent and 70 percent, various break sizes have been defined from the full double-ended rupture of a main steamline down to the break of the smallest line, which cannot be isolated in the MSS.

Cases are chosen for the RSG analysis based on the results of the analyses presented in the Power Uprate Project NSSS Licensing Report, which is based on the many cases documented in Reference 4. A subset of the 28 cases noted in the Power Uprate Project NSSS Licensing Report is analyzed at conditions associated with the RSGs assuming isolation is accomplished by the redundant swing-disc isolation valves in each steamline. The important plant conditions and features that are assumed are discussed in the following paragraphs.

INITIAL POWER LEVEL

The initial power, assumed for steamline break analyses outside containment, affects the M&E releases and steam generator tube bundle uncovery in two ways. First, the steam generator mass inventory increases with decreasing power levels; this will tend to delay uncovery of the steam generator tube bundle, although the increased steam pressure associated with lower power levels will cause a faster blowdown at the beginning of the transient. Second, the amount of stored energy and decay heat, as well as feedwater temperature, are less for lower power levels; this will result in lower primary temperatures and less primary-to-secondary heat transfer during the steamline break event.

Overall, steamline breaks initiated from lower power levels result in lower levels of steam superheating than breaks analyzed at full-power conditions. For this reason, steamline break outside containment M&E release calculations are limited to breaks initiated from full-power or near full-power conditions; specifically:

- Full power — maximum allowable NSSS power plus uncertainty, i.e., 102 percent of rated power

- Near full-power — 70 percent of maximum allowable NSSS power

For this RSG analysis, the power levels and steamline break sizes are noted in Section 4.5.2.3 of this report.

In general, the plant initial conditions are assumed to be at the nominal value corresponding to the initial power for that case, with appropriate uncertainties included. Tables 4.5-1 and 4.5-2 identify the values assumed for RCS pressure, RCS vessel average temperature, pressurizer water volume, steam generator water level, and feedwater enthalpy corresponding to each power level analyzed.

SINGLE-FAILURE ASSUMPTION

The limiting single failure is the failure of the turbine-driven AFW pump to start. AFW flow can have a significant impact on the calculated M&E releases following a steamline break outside containment. With respect to the production of superheated steam, increased AFW flow can have the beneficial effect of reducing the enthalpy of the mass release. Variations in AFW flow can affect steamline break M&E releases in a number of ways, including: break mass flowrate, RCS temperature, tube bundle uncovery time, and steam superheating. The failure of the turbine-driven AFW pump results in a minimum AFW flow to the steam generators; minimum AFW flow is based on two motor-driven AFW pumps.

MAIN FEEDWATER SYSTEM

The main feedwater system was conservatively modeled for the steamline break M&E releases outside containment by assuming the following:

- Nominal main feedwater flow corresponding to the initial power until the time of reactor trip

- Nominal main feedwater temperature corresponding to the initial power

The rapid depressurization, which typically occurs following a steamline rupture, results in large amounts of water being added to the steam generators through the main feedwater system. However, main feedwater flow was conservatively modeled by assuming no increase in feedwater flow in response to the increases in steam flow following the steamline break event. This minimizes the total mass addition and associated cooling effects in the steam generators. High main feedwater temperatures are assumed to minimize the cooling effect of the main feedwater.

Isolation of the main feedwater flow is conservatively assumed to be coincident with reactor trip, irrespective of the function that produced the reactor trip signal. This assumption reduces the total mass addition to the steam generators. Closing of the feedwater flow control valves in the main feedwater lines is assumed to be instantaneous with no consideration of associated signal processing or valve stroke time.

AUXILIARY FEEDWATER SYSTEM

Generally, within the first few minutes following a steamline break, the AFWS (i.e., motor-driven AFW pumps) is initiated on any one of several protection system signals. Addition of auxiliary feedwater to the steam generators will increase the secondary-side mass available to cover the tube bundle and reduces the amount of superheated steam produced. For this reason, AFW flow is delayed and minimized to accentuate the depletion of the initial secondary-side inventory. The AFW flow to all steam generators is a function of the backpressure in the steam generators.

STEAM GENERATOR FLUID MASS

A minimum initial steam generator mass in all the steam generators is used in all of the analyzed cases. The use of a reduced initial steam generator mass minimizes the availability of the heat sink afforded by the steam generators and leads to earlier tube bundle uncovery. The initial mass is calculated as the value corresponding to the programmed level -7 percent NRS. All steam generator fluid masses are calculated assuming 0 percent tube plugging. This assumption is conservative with respect to the RCS cooldown through the steam generators that results from the steamline break. A negative mass uncertainty is applied to the steam generator initial conditions and is in addition to the programmed -7 percent NRS level uncertainty previously mentioned.

MAIN STEAMLINE ISOLATION

Steamline isolation is assumed in all loops to terminate the blowdown from those steam generators for all break sizes except for the smallest (0.05 ft^2). The main steamline isolation function is accomplished via two redundant swing-disc isolation valves in each of the three steamlines. Both valves close on an isolation signal to terminate steam flow from the associated steam generator. A failure in one of the two valves has no effect for a main steamline rupture downstream of the valves since the isolation function will be performed by the other valve in the same steamline. Therefore, once a signal to isolate the main steamlines is received (on a low steamline pressure setpoint), the steam blowdown is terminated.

However, a main steamline rupture upstream of these valves will create a situation in which the steam generator on the faulted loop cannot be isolated. The contents of this steam generator and any AFW flow to it will blowdown continually until the AFW flow is terminated. The main steamlines outside containment up to the isolation valves conform to Branch Technical Positions APCSB 3-1 and MEB 3-1; therefore, a rupture in these pipes is not postulated. The only postulated break outside containment upstream of the isolation valves is the 3 inch diameter branch line to the turbine-driven AFW pump. This line is not part of the "no break zone" and a break must be postulated in this line. Thus, the only break upstream of the isolation valves which must be considered for Farley is the 3 inch (0.05 ft^2) branch line to the turbine-driven AFW pump.

A delay time of 12 seconds is assumed (two second signal processing time plus 10 second valve stroke time) with unrestricted steam flow assumed through the valve during the valve stroke. The assumption of unrestricted steam flow from the intact steam generators for this time conservatively accounts for the effects of the steam mass in the isolable volume which would be released prior to the closure of the isolation valve in the steamline with the pipe break.

BREAK FLOW MODEL

Piping discharge resistances are not included in the calculation of the releases resulting from the steamline ruptures [Moody Curve for an f(L/D) = 0 was used].

PROTECTION SYSTEM ACTUATIONS

The protection systems available to mitigate the effects of a MSLB accident outside containment include reactor trip, SI, steamline isolation, and auxiliary feedwater. The protection system actuation signals and associated setpoints that are modeled in the analysis are identified in Table 4.5-3. The setpoints used are conservative values with respect to the Farley plant-specific values delineated in the Technical Specifications.

At 102 percent power for break sizes from 0.6 ft^2 and larger, the first protection system signal actuated is low steamline pressure (lead/lag compensated in each channel) in two loops, which initiates steamline isolation and SI; the SI signal produces a reactor trip signal. Main feedwater flow is conservatively assumed to be isolated at the time of reactor trip; motor-driven AFW initiation occurs as a result of the SI signal. For break sizes smaller than this, reactor trip is actuated following either the Overpower ΔT (2-out-of-3 channels) or low-low steam generator water level (2-out-of-3 channels in any loop) signal; SI is started as a result of a low pressurizer pressure (2-out-of-3 channels) signal; steamline isolation occurs later due to low steamline pressure or manually at 30 minutes. Main feedwater flow is conservatively assumed to be isolated at the time of reactor trip. AFW flow is initiated following the low-low steam generator water level signal.

At 70 percent power for break sizes from 0.6 ft^2 and larger, the first protection system signal actuated is low steamline pressure (lead/lag compensated in each channel) in 2 loops, which initiates steamline isolation and SI; the SI signal produces a reactor trip signal. Main feedwater flow is conservatively assumed to be isolated at the time of reactor trip; motor-driven AFW initiation occurs as a result of the SI signal. For break sizes smaller than this, reactor trip and motor-driven AFW initiation are actuated following a low-low steam generator water level (2-out-of-3 channels in any loop) signal; SI is started as a result of a low pressurizer pressure (2-out-of-3 channels) signal; steamline isolation occurs later due to low steamline pressure or manually at 30 minutes. Main feedwater flow is conservatively assumed to be isolated at the time of reactor trip.

SAFETY INJECTION SYSTEM

Minimum SIS flowrates corresponding to the failure of one SIS train are assumed in this analysis. A minimum SIS flow is conservative since the reduced boron addition maximizes a return to power resulting from the RCS cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break. The delay time to achieve full SIS flow is assumed to be 27 seconds for this analysis with offsite power available. A coincident loss of offsite pow er is not assumed for the analysis of the steamline break outside containment since the M&E releases are reduced due to the loss of forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

RCS METAL HEAT CAPACITY

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, and the reactor coolant pumps. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. Stored metal heat does not have a major impact on the calculated M&E releases. The effects of this RCS metal heat are included in the results using conservative thick metal masses and heat transfer coefficients.

CORE DECAY HEAT

Core decay heat generation assumed in calculating the steamline break M&E releases is based on the 1979 ANS Decay Heat + 2s model (Reference 2).

ROD CONTROL

The rod control system is conservatively assumed to be in manual operation for all steamline break analyses.

CORE REACTIVITY COEFFICIENTS

Conservative core reactivity coefficients corresponding to end of cycle (EOC) conditions are used to maximize the reactivity feedback effects resulting from the steamline break. Use of maximum reac y feedback results in higher power generation if the reactor returns to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

4.5.2.3 Description of Analysis

The break flows and enthalpies of the steam release through the steamline break outside containment are analyzed with the LOFTRAN computer code. Blowdown M&E releases determined using LOFTRAN include the effects of core power generation, main and auxiliary feedwater additions, ESSs, RCS thick metal heat storage, ar d reverse steam generator heat transfer.

The Farley NSSS is analyzed using LOFTRAN to determine the transient steam M&E releases outside containment following a steamline break event. The tables of M&E releases are used as input conditions to the environmental evaluation of safety-related electrical equipment in the main steam valve room.

The following licensing-basis cases of the MSLB outside containment were analyzed with the RSG assumptions:

- At 102 percent power, break sizes of 0.6, 0.5, 0.4, 0.3, 0.2, 0.1, and 0.05 ft^2
- At 70 percent power, break sizes of 0.6, 0.5, 0.4, 0.3, 0.2, 0.1, and 0.05 ft^2

4.5.2.4 Acceptance Criteria

The main steamline break is classified as an ANS Condition IV event, an infrequent fault. Additional clarification of the ANS classification of this event is presented in Section 4.2.19 of this report, which discusses the core response to a steamline break event. The acceptance criteria associated with the steamline break event resulting in a M&E release outside containment is based on an analysis that provides sufficient conservatism to ensure that the equipment qualification temperature envelope is maintained. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, the break flow model, steamline and feedwater isolation, and main and auxiliary feedwater flow such that superheated steam resulting from tube bundle uncovery in the steam generators is accounted for and maximized. These analysis assumptions have been included in this steamline break M&E release analysis as discussed in Reference 4 and subsection 4.5.2.2 of this report. The tables of M&E release data for each of the steamline break cases noted in the previous section are used as input to the environmental evaluation of safety-related electrical equipment in the main steam valve room.

4.5.2.5 Results

Using Reference 4 and the Power Uprate Project NSSS Licensing Report (WCAP-14723) as bases, including parameter changes associated with the RSG, the M&E release rates for each of the steamline break cases noted in Section 4.5.2.3 were developed for use in the environmental evaluation of safety-related electrical equipment in the main steam valve room. Tables 4.5-6 and 4.5-7 provide the sequence of events for the various steamline break sizes at 102 percent and 70 percent power, respectively. Steamline break M&E release rate data, accounting for superheated steam releases, analyzed for the Farley RSGs are provided in the BOP Licensing Report.

4.5.2.6 Conclusions

The M&E releases from a subset of the steamline break cases have been analyzed with RSG assumptions. The assumptions delineated in Section 4.5.2.2 have been included in the steamline break analysis such that the applicable acceptance criteria are met. The steam M&E releases discussed in this section have been provided for use in the environmental evaluation of safety-related electrical equipment in the main steam valve room in support of the Farley RSG (see BOP Licensing Report).

4.5.3 Steam Releases for Radiological Dose Analysis

The vented steam releases have been calculated for the Loss of Load/Turbine Trip (LOL/TT) and Steamline Break (SLB) events. The calculated values for the steam releases following a LOL/TT event bound those that would be calculated for the LOOP and locked rotor events. Information documented in Tables 15.2-3 and 15.4-23 of the Farley FSAR includes steam releases and main feedwater flow; therefore data along the same lines is included herein. The following table summarizes the vented steam releases from the operable steam generators and main feedwater flows for the 0 to 2 hour time period and the 2 to 8 hour time period for each of these events. These two time periods are documented to support the current licensing-basis radiological calculations for Farley.

Event	Vented Steam Release		Feedwater Flow	
	0-2 hours	2-8 hours	0-2 hours	2-8 hours
Loss of Load/Turbine Trip, Loss of Offsite Power, and Locked Rotor	512,325 lbm	833,221 lbm	693,629 lbm	844,963 lbm
Steamline Break	316,715 lbm	703,687 lbm	437,585 lbm	711,515 lbm

For the SLB event, additional steam is released through the faulted steam generator from the initiation of the transient up through the time at which isolation of AFW flow is assumed (at 1800 seconds into the event). This additional total steam mass is 439,145 lbm and is comprised of the initial steam generator inventory (167,050 lbm) plus main feedwater flow until automatic isolation and AFW flow until manual isolation at 1800 seconds (272,095 lbm). Since AFW flow to the faulted steam generator is assumed to be isolated at 1800 seconds, the steam release from the faulted steam generator is confined to the 0 to 2 hour time period and does not contribute to the steam release beyond the 0 to 2 hour time period.

No explicit assumption is considered in this analysis regarding steam generator blowdown isolation. The implied assumption is that the entire inventory of the steam generators is released to the environment and no loss of inventory through the blowdown line is assumed. This provides a conservative calculation of the quantity of steam vented during the noted time periods.

The steam releases discussed in this section have been provided as input to the radiological dose analysis in support of the Farley RSG (see BOP Licensing Report).

4.5.4 References

1. Huegel, D. S., et al., *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analysis*, WCAP-14882 (Proprietary), June 1997

2. *American National Standard for Decay Heat Power in Light Water Reactors*, ANSI/ANS-5.1-1979, August 1979

3. McFadden, J. H., et al., *RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, EPRI NP-1850-CCMA, April 1984

4. Butler, J. C., and Love, D. S., *Steamline Break Mass/Energy Releases for Equipment Environmental Qualification Outside Containment*, WCAP-10961-R1 (Proprietary) and WCAP-11184 (Non-Proprietary), Revision 1, Report to the Westinghouse Owners Group High Energy Line Break/Superheated Blowdowns Outside Containment Subgroup, October 1985

Table 4.5-1
Farley Units 1 and 2
Nominal Plant Parameters for RSG(1)
(MSLB M&E Releases)

Nominal Conditions	
NSSS Power, MWt	2785
Core Power, MWt	2775
Reactor Coolant Pump Heat, MWt	10
Reactor Coolant Flow (total), gpm	258,000
Pressurizer Pressure, psia	2250
Core Bypass, %	7.1
Reactor Coolant Temperatures, °F	
Core Outlet	618.1
Vessel Outlet	613.3
Core Average	581.8
Vessel Average	577.2(1)
Vessel/Core Inlet	541.1
Steam Generator	
Steam Temperature, °F	520.6
Steam Pressure, psia	817
Steam Flow (total), 10^6 lbm/hr	12.26
Feedwater Temperature, °F	443.4
Zero-Load Temperature, °F	547

Notes:

(1) Noted values correspond to plant conditions defined by 0 percent steam generator tube plugging and the high end of the RCS T_{avg} window.

Table 4.5-2
Farley Units 1 and 2
Initial Condition Assumptions for RSG(1)

MSLB M&E Releases Inside Containment

Initial Conditions	Power Level (%)			
Parameter(1)	**102**	**70**	**30**	**0**
RCS Average Temperature (°F)	583.2(2)	573.1(2)	561.2(2)	547.2
RCS Flowrate (gpm)	258,000	258,000	258,000	258,000
RCS Pressure (psia)	2250	2250	2250	2250
Pressurizer Water Volume (ft^3)	772.4	620.0	451.0	350.8
Feedwater Enthalpy (Btu/lbm)	423.1	375.2	304.6	70.0
SG Water Level, faulted/intact (% span)(3)	74/58	74/58	74/58	72/58

MSLB M&E Releases Outside Containment

Initial Conditions	Power Level (%)	
Parameter	**102**	**70**
RCS Average Temperature (°F)	583.2(2)	574.14(2)
RCS Flowrate (gpm)	258,000	258,000
RCS Pressure (psia)	2250	2250
Pressurizer Water Volume (ft^3)	772.4	646.4
Feedwater Enthalpy (Btu/lbm)	423.0	377.5
SG Water Level (% span)	58	58

Notes:

(1) The initial conditions are target values that may vary slightly in RETRAN from the noted values, particularly at powers less than full power.

(2) Noted values correspond to plant conditions defined by 0 percent steam generator tube plugging and the high end of the RCS T_{avg} window.

(3) These levels were not used in RETRAN; however, these levels are the basis for the secondary-side mass in RETRAN.

Table 4.5-3 Farley Units 1 and 2 Protection System Actuation Signals and Safety System Setpoints for RSG Analysis
MSLB M&E Releases Inside Containment
1. <u>Reactor Trip</u> • 2/3 Low Pressurizer Pressure - 1846 psia • Safety Injection
2. <u>Safety Injection</u> • 2/3 Low Pressurizer Pressure - 1700 psia • 1/1 Low Steamline Pressure in 2/3 loops - 551.7 psia – dynamic compensation lead - 50 seconds – dynamic compensation lag - 5 seconds • 2/3 High Containment Pressure(1)
3. <u>Steamline Isolation</u> • 1/1 Low Steamline Pressure in 2/3 loops - 551.7 psia – dynamic compensation lead - 50 seconds – dynamic compensation lag - 5 seconds • 2/3 High-High Containment Pressure(1)
4. <u>Feedwater Isolation and Auxiliary Feedwater Initiation</u> • Safety Injection

<u>Notes</u>:

(1) Setpoint not explicitly modeled in MSLB M&E release analyses; it is used in the containment pressure response analysis).

Table 4.5-3 (Cont.)
Farley Units 1 and 2
Protection System Actuation Signals and
Safety System Setpoints for RSG Analysis

MSLB M&E Releases Outside Containment

5. Reactor Trip

- 2/3 Low-Low Steam Generator Water level in any loop - 0% narrow-range span
- 2/3 Low Pressurizer Pressure - 1846 psia
- 2/4 Power-Range High Neutron Flux - 118% rated thermal power
- 2/3 Overtemperature ΔT
  - K1 = 1.33
  - K2 = 0.017
  - K3 = 0.000825
  - dynamic compensation lead - 30 seconds
  - dynamic compensation lag - 4 seconds
- 2/3 Overpower ΔT
  - K4 = 1.166
  - K5 = 0.0
  - K6 = 0.00109 (set to 0 for indicated temperature < reference temperature)
  - dynamic compensation rate lag - 10 seconds
- Safety Injection

6. Safety Injection

- 2/3 Low Pressurizer Pressure - 1700 psia
- 1/1 Low Steamline Pressure in 2/3 loops - 551.7 psia
  - dynamic compensation lead - 50 seconds
  - dynamic compensation lag - 5 seconds

7. Steamline Isolation

- 1/1 Low Steamline Pressure in 2/3 loops - 551.7 psia
  - dynamic compensation lead - 50 seconds
  - dynamic compensation lag - 5 seconds

8. Feedwater Isolation

- Coincident with Reactor Trip (Conservative assumption)

9. Auxiliary Feedwater Initiation (Motor-driven AFW pumps)

- 2/3 Low-Low Steam Generator Water Level in any loop - 0% narrow-range span
- Safety Injection

Table 4.5-4
Farley Units 1 and 2
1.069 Ft² MSLB Hot Full Power with Containment Safeguards Failure
Sequence of Events

(Peak Temperature Case)

Time (sec)	Event Description
0.0	Main Steamline Break Occurs
0.066	Low Steamline Pressure Setpoint (551.7 psia) Reached in 2 Loops
5.1	High Containment Pressure Setpoint (7.0 psig) Reached
2.066	Rod Motion Starts (Low Steamline Pressure Actuates SI which Initiates Reactor Trip)
9.066	Feedwater Isolation Occurs
14.6	High-High Containment Pressure Setpoint (19.2 psig) Reached
12.066	Steamline Isolation Occurs (Following Receipt of the Low Steamline Pressure Signal)
27.1	Safety Injection Flow Initiated
92.1	Containment Fan Cooler (1 cooler) Actuates
92.2	Peak Containment Temperature (367°F) Occurs
94.1	High-High-High Containment Pressure Setpoint (30 psig) Reached
142.1	Containment Spray (1 train) Actuates
1800.0	Auxiliary Feedwater Flow Isolated by Operator
1838.0	Peak Containment Pressure (39.3 psig) Occurs
1925.0	M&E Releases Terminate (Steam Generator Dryout)

Table 4.5-5
Farley Units 1 and 2
1.069 Ft^2 MSLB Hot Zero Power with Containment Safeguards Failure
Sequence of Events

(Peak Pressure Case)

Time (sec)	Event Description
0.0	Main Steamline Break Occurs
0.091	Low Steamline Pressure Setpoint (551.7 psia) Reached in 2 Loops
1.4	High Containment Pressure Setpoint (7.0 psig) Reached
2.091	Rod Motion Starts (Low Steamline Pressure Actuates SI which Initiates Reactor Trip)
8.6	High-High Containment Pressure Setpoint (19.2 psig) Reached
9.091	Feedwater Isolation Occurs
12.091	Steamline Isolation Occurs (Following Receipt of the Low Steamline Pressure Signal)
27.09	Safety Injection Flow Initiated
40.1	High-High-High Containment Pressure Setpoint (30 psig) Reached
87.2	Peak Containment Temperature (342°F) Occurs
88.1	Containment Spray (1 train) Actuates
88.4	Containment Fan Cooler (1 cooler) Actuates
573.0	Peak Containment Pressure (52.0 psig) Occurs
1800.0	Auxiliary Feedwater Flow Isolated by Operator
1890.0	M&E Releases Terminate (Steam Generator Dryout)

Table 4.5-6
Farley Units 1 and 2
Transient Summary for the Spectrum of Breaks at 102% Power - Outside Containment

Power Level (%Nom)	Break Size (ft^2)	Reactor Trip Signal	Safety Injection Signal	Reactor Trip (sec)	Feedwater Isolation (sec)	Safety Injection (sec)	Steamline Isolation (sec)	Auxiliary Feedwater (sec)	SG Tube Uncovery (sec)
102	0.6	LSP(1)	LSP(1)	7.1	7.1	32.1	17.1	65.1	NA(6)
102	0.5	OPΔT(2)	LPP(4)	36.5	36.5	137.2	171.3	149.1	335.5(6)
102	0.4	OPΔT(2)	LPP(4)	62.7	2.7	187.3	395.3	172.6	281.5
102	0.3	LLSGL(3)	LPP(4)	177.2	177.2	340.0	444.5	235.2	299.5
102	0.2	LLSGL(3)	LPP(4)	257.5	257.5	514.1	696.5	315.5	406.5
102	0.1	LLSGL(3)	LPP(4)	497.6	497.6	1112.1	1800 (M)(5)	555.6	603.5
102	0.05	LLSGL(3)	NA	977.6	977.6	NA	1800 (M)(5)	1035.6	1269.5

Notes:

(1) LSP - Low Steamline Pressure
(2) OPΔT - Overpower ΔT
(3) LLSGL - Low-Low Steam Generator Water Level
(4) LPP - Low Pressurizer Pressure
(5) M - Manual Actuation
(6) Since steamline isolation is calculated to occur before steam generator tube uncovery, the transient is terminated before uncovery occurs.

Table 4.5-7
Farley Units 1 and 2
Transient Summary for the Spectrum of Breaks at 70% Power - Outside Containment

Power Level (%Nom)	Break Size (ft^2)	Reactor Trip Signal	Safety Injection Signal	Reactor Trip (sec)	Feedwater Isolation (sec)	Safety Injection (sec)	Steamline Isolation (sec)	Auxiliary Feedwater (sec)	SG Tube Uncovery (sec)
70	0.6	LSP[(1)]	LSP[(1)]	9.3	9.3	34.3	19.3	67.3	NA[(5)]
70	0.5	LLSGL[(2)]	LPP[(3)]	101.0	101.0	204.1	215.0	159.0	344.5[(5)]
70	0.4	LLSGL[(2)]	LPP[(3)]	122.8	122.8	212 9	285.1	180.8	363.5[(5)]
70	0.3	LLSGL[(2)]	LPP[(3)]	159.0	159.0	321.3	643.9	217.0	418.5
70	0.2	LLSGL[(2)]	LPP[(3)]	231.2	231.2	479.3	1102.0	289.2	530.5
70	0.1	LLSGL[(2)]	LPP[(3)]	446.8	446.8	989.0	1800 (M)[(4)]	504.8	816.5
70	0.05	LLSGL[(2)]	NA	876.9	876.9	NA	1800 (M)[(4)]	934.9	1418.5

Notes:
(1) LSP - Low Steamline Pressure
(2) LLSGL - Low-Low Steam Generator Water Level
(3) LPP - Low Pressurizer Pressure
(4) M - Manual Actuation
(5) Since steamline isolation is calculated to occur before steam generator tube uncovery, the transient is terminated before uncovery occurs.

4.6 REACTOR TRIP SYSTEM/ENGINEERED SAFETY FEATURE ACTUATION SYSTEM SETPOINTS

The Technical Specification Reactor Trip System/ESFAS setpoints have been reviewed for plant operation at RSG conditions including a core power level up to 2775 MWt. As part of the review, Technical Specifications changes were made consistent with Westinghouse setpoint methodologies. These methodologies were part of the Power Uprate Project submittal to the NRC.

As indicated in Table 4.6-2, the steam generator water level high-high and low-low setpoints both increased with the Model 54F steam generator. The steam generator water level high-high and low-low setpoints are predicated on the need to maintain the water level with respect to certain locations within the steam generator, for example, hardware within the steam generator such as the mid-deck plate and lower-deck plate.

The elevations of certain steam generator internal hardware increased in reference to the tubesheet, this, in conjunction with minor changes in the steam generator secondary-side mass, necessitated the water level setpoint changes.

The methodology employed in the determination of the reactor trip system/ESFAS steam generator narrow range level setpoints, including the process measurement uncertainty allowances, is consistent to that used for the Power Uprate Project.

The technical specifications criteria for the steam generator water level in modes 3,4 and 5 is increased for the RSG from 74 percent to 75 percent of wide range span. The value is determined by adding the wide range level nonadverse instrument channel uncertainty to the elevation associated with the top of the tubes. The elevation of the tubes increased slightly for the RSG to 70.5 percent of wide range span. The calculated nonadverse uncertainty is 3.9 percent of wide range span. A criteria of 75 percent of wide range span will, therefore, be used for the technical specification secondary-side steam generator water level associated with the wide range indication.

Tables 4.6-1 and 4.6-2 list both the power uprate and RSG values for each impacted function and parameter. Incorporating these Technical Specifications changes will ensure that the Farley Units 1 and 2 will operate in a manner consistent with the FSAR and power uprate assumptions.

Table 4.6-1
Summary of the Technical Specification
Reactor Trip System Setpoint Changes for Farley RSG

Steam Generator Water Level Low-Low Reactor Trip				
Functional Unit 14	**Trip Setpoint**		**Allowable Value**	
	Power Uprate Value	**RSG Value**	**Power Uprate Value**	**RSG Value**
Low Low Setpoint	≥25.0% of span	≥28.0% of span	≥24.6% of span	≥27.6% of span

Table 4.6-2
Summary of the Technical Specification
ESFAS Setpoint Changes for Farley RSG

Steam Generator Water Level -- High-High, Turbine Trip & Feedwater Isolation				
Functional Unit 5.b	Trip Setpoint		Allowable Value	
	Power Uprate Value	RSG Value	Power Uprate Value	RSG Value
High-High Setpoint	≤78.5% of span	≤82.0% of span	≤78.9% of span	≤82.4% of span
Steam Generator Water Level Low-Low, Auxiliary Feedwater Start				
Functional Unit 6.b	Trip Setpoint		Allowable Value	
	Power Uprate Value	RSG Value	Power Uprate Value	RSG Value
Low-Low Setpoint	≥25.0% of span	≥28.0% of span	≥24.6% of span	≥27.6% of span

Attachment 5

Joseph M. Farley Nuclear Plant
Steam Generator Replacement Related Technical Specifications Change Request

BOP Licensing Report

Farley Nuclear Plant Units 1 and 2
Steam Generator Replacement Program
BOP Licensing Report

November 1998

SOUTHERN COMPANY

Energy to Serve Your World

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Nuclear Engineering and Regulatory Support

Southern Company Services, Inc.
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Birmingham, Alabama 35202

STEAM GENERATOR REPLACEMENT (SGR)
BOP LICENSING REPORT

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1.0 Executive Summary

The purpose of the Farley Nuclear Plant (FNP) steam generator replacement program is to replace the existing Model 51 steam generators with Westinghouse Model 54F steam generators. In order to determine the potential impact on major plant design features, a detailed systems and safety analyses review was conducted by Southern Nuclear Operating Company (SNC), Westinghouse, Bechtel, and Southern Company Services (SCS) to demonstrate the acceptability of the replacement steam generators.

The NSSS analyses and evaluations prepared to support steam generator replacement are described in WCAP-15098, "Farley Nuclear Plant Units 1 and 2 Replacement Steam Generator Program NSSS Licensing Report," September 1998. This report provides descriptions of the evaluations of the design and licensing aspects of balance of plant (BOP) systems, structures, components, and analyses not included in the NSSS Licensing Report, including radiological releases and doses, qualification of safety-related electrical equipment, and environmental impact. The portions of the BOP scope not adversely impacted[a] by steam generator replacement or determined to be bounded by the power uprate evaluations are listed in Table 2-1.

The BOP analyses and evaluations used the same input assumptions and parameter values listed in the NSSS Licensing report. The input assumptions and parameter values were developed jointly among involved organizations and are procedurally controlled.

The BOP analyses and evaluations demonstrate that FNP remains in compliance with the applicable design and licensing bases and can operate acceptably with the Model 54F steam generators installed. This report, in part, provides the technical basis for the conclusions presented in the significant hazards evaluation for the proposed Technical Specifications changes required for the Farley steam generator replacement project.

(a) The term "not adversely impacted" is used when the results of an evaluation performed for steam generator replacement demonstrate only a minimal change to the current analysis of record, and the analysis continues to meet acceptance criteria. The analyses presented in this report either support Technical Specifications changes or are not considered bounded by previous NRC reviewed submittals.

2.0 BOP Program Description

2.1 Introduction/Background

Farley Nuclear Plant (FNP) is a two unit site. Each unit is currently licensed for a rated thermal power of 2775 MWt with Westinghouse Model 51 steam generators. Southern Nuclear Operating Company (SNC) proposes to replace the Model 51 steam generators with Westinghouse Model 54F steam generators. In order to determine the potential impact on major plant design features, systems and safety analyses, a detailed programmatic review was conducted by SNC, Westinghouse, Bechtel, and Southern Company Services (SCS). These reviews included performance of NSSS and BOP analyses and evaluations.

2.2 Quality Assurance and Code Requirements

The BOP analyses and evaluations to support the use of Model 54F steam generators were performed in accordance with quality assurance program requirements and engineering procedures which comply with 10 CFR 50 Appendix B. These analyses and evaluations also conform to industry codes and standards, including the regulatory requirements applicable to FNP. The principal computer codes used in the BOP evaluations are used in conformance with their limitations and restrictions, and are the same codes used for power uprate, *i.e.*, GOTHIC, COMPACT and TACT5 as discussed in Sections 3 and 5 respectively.

2.3 Scope of Review

The results of the analyses and evaluations for NSSS systems, components, and transient and accident analyses are presented in the NSSS Licensing Report (WCAP-15098). The BOP Licensing Report provides descriptions of the evaluations of the design and licensing aspects of BOP systems, structures, components and analyses, including radiological releases and doses, qualification of safety-related electrical equipment, and environmental impact. Analyses and evaluations that are not adversely impacted by steam generator replacement, or are bounded by previous submittals (*e.g.*, power uprate) and therefore are not changed, are listed in Table 2-1. The BOP analyses and evaluations include input from the NSSS analyses and evaluations as required, and in some cases, BOP results provide information for the NSSS analyses and evaluations. These interfaces were developed jointly among the involved organizations.

Where differences between Unit 1 and Unit 2 exist, each unit was evaluated, or a bounding analysis or evaluation for both units was performed. No significant differences between units were identified which would adversely impact the replacement of steam generators.

2.4 Plant and Technical Specification Changes

Technical Specifications changes required as a result of the BOP analyses and evaluations are associated with RCS specific activity and primary to secondary leakage used in the radiological analyses. The Technical Specification Bases sections for RCS Specific Activity, RCS Operational Leakage and Secondary Specific Activity will be revised to reflect the results of the new radiological analyses. In addition, the Technical Specification Administrative section for the Containment Leak Rate Testing Program will be revised to reflect the results of the containment response analysis.

Table 2-1

Summary of BOP Analyses and Evaluations

System, Structure, Component Or Program Description	Included in SGR BOP Licensing Report	Bounded by Uprate or Not Adversely Impacted[a] by SGR
Condensate and Feedwater		X
Circulation Water		X
Main Turbine Evaluations		X
Main Turbine Auxiliaries		X
Main Generator & Auxiliaries		X
Main Steam		X
CCW		X
Service Water		X
Spent Fuel Pool		X
LHSI (RHR) / HHSI (Charging)		X
Auxiliary Feedwater	X	
Containment and Subcompartment Analysis	X	
Post LOCA Hydrogen Generation	X	
Safety Related Electrical Equipment Qualification	X	
Radiological Assessment	X	
Containment Ventilation		X
Auxiliary Building Ventilation		X
Misc. Mechanical Reviews		X
Misc. Electrical Reviews		X
Misc. I&C Reviews		X
Environmental Evaluations	X	

(a) The term "not adversely impacted" is used when the results of an evaluation performed for steam generator replacement demonstrate only a minimal change to the current analysis of record, and the analysis continues to meet acceptance criteria. The analyses presented in this report either support Technical Specifications changes or are not considered bounded by previous NRC reviewed submittals.

3.0 CONTAINMENT & SUBCOMPARTMENT ANALYSIS

3.1 Containment Structure - Analysis Description

Each Farley containment structure is designed to withstand an internal pressure of -3 psig to +54 psig and a temperature of 280°F. Power uprate containment analyses were performed using the EPRI GOTHIC code. The containment analysis results demonstrate the acceptability of the containment structure and subcompartment design. Additionally, the containment analysis is used to generate design pressure and temperature curves for use in the evaluation of safety-related electrical equipment inside the containment in accordance with the provisions of 10 CFR 50.49 and the analysis of hydrogen generation in the containment.

The analyses performed for steam generator replacement made use of previous power uprate work to the maximum extent possible. The most significant changes are those associated with changes in the mass and energy blowdown from pipe breaks. Blowdown mass and energy values have changed because of the change in steam generator design and also because of refinements in blowdown computational methods as described in the NSSS Licensing Report.

In addition to the containment analysis, the main steamline break in the main steam valve room (MSVR) was also assessed. The results are included in this section.

The containment coolers, spray systems and residual heat removal systems designs for both Farley units are identical. The containment analyses are based on a bounding, degraded containment cooler. Due to differences in the reactor (up flow vs. down flow), separate blowdown values were analyzed for each unit; however, only the limiting results are presented. A single, bounding MSVR analysis was prepared. Therefore, the analysis results presented are applicable to both units.

3.2 Scope of Review

This review consists of four principal parts.

The first part evaluates the containment response to design basis LOCA events. It has been determined that the hot leg break results in the most limiting pressure during the blowdown phase. It has further been determined that the pump suction break yields the highest energy flow rates during the post-blowdown period. Therefore, the containment pressure and temperature transient is analyzed for only the blowdown period for the hot leg break and is analyzed for the entire event for the pump suction break. Since the Technical Specifications permit operation at +3 psig containment pressure, the LOCA analyses were performed assuming this initial pressure.

The second part evaluates the containment response to the various steam line breaks. Since current Technical Specifications permit operation at +3 psig initial containment pressure, the MSLBs that are limiting for pressure were run with an initial condition of +3 psig. The current Technical Specifications permit operation at a containment pressure of -1.5 psig, thus MSLBs that are limiting for temperature were analyzed at a pressure of -1.5 psig, which bounds the ITS value of -1.0 psig. Five MSLB cases that gave the limiting pressure and temperature results for power uprate were analyzed for steam generator replacement.

Case 1:	102% Power, 1.069 ft^2 double ended
Case 8:	70% Power, 0.47 ft^2 split break
Case 9:	30% Power, 1.069 ft^2 double ended rupture
Case 12:	30% Power, 0.60 ft^2 split break
Case 13:	0% Power, 1.069 ft^2 double ended rupture

The third part evaluates the impact upon containment subcompartments for breaks of the pressurizer surge line.

The fourth part consists of an analysis of the main steamline break in the main steam valve room. Because no significant operating parameter changes have been made for other high energy lines, breaks in other systems were not re-evaluated.

3.3 Design Interfaces

Containment pressure and temperature transient curves developed in the analysis are used in the assessment of qualification of safety related electrical equipment, evaluation of post-LOCA hydrogen generation, and in the development of test criteria for containment integrated leak rate testing.

Containment cooler duty curves and containment spray system performance are interfaces because the cooler and spray system performance are inputs to the containment pressure/temperature analysis.

3.4 Assumptions

There is little difference in the steam generator replacement model and the SG model used in the power uprate analysis[1]. Minimum safeguards performance is assumed for all cases because the minimum safeguards cases have proven to be limiting in past analyses. Minimum safeguards consist of one containment cooler and one train of containment spray, safety injection, residual heat removal, component cooling water, and service water. The principal difference between the uprate and RSG analyses is the change in the blowdown data (see the NSSS Licensing Report). Other changes are summarized below:

(a) RHR heat exchange properties (heat transfer coefficient and CCW flow) were modified to represent plant design data with a margin for future tube plugging.

(b) Although leak-before-break approval on Farley included the pressurizer surge line, blowdown from this line was used as bounding input for the reactor coolant loop subcompartment analyses. Additional changes to reflect the Model 54F steam generator and new grating platforms were also included in the model.

3.5 Methods of Evaluation

3.5.1 LOCA and MSLB Inside Containment

The LOCA and MSLB inside containment analyses were performed using the GOTHIC computer code as approved for Farley containment analyses[2]. Since the pressurizer spray and surge line conditions do not change for steam generator replacement, the pressurizer compartment was not re-analyzed. RCS loop subcompartment re-analysis using the limiting pressurizer surge line break blowdown was also performed using the GOTHIC computer code.

3.5.2 Main Steam Valve Room

The impact of the replacement steam generators (RSGs) on the steam line break transients in the main steam valve room (MSVR) was evaluated with the COMPACT code. This code has been used previously to address steam line breaks for this region as described in FSAR, Appendix 3J.

3.6 Summary of Evaluation

The evaluation of the RSG containment analysis results demonstrates that the containment structure design pressure and temperature limits (54 psig and 280 °F) are not exceeded by the steam generator replacement LOCA and MSLB accident conditions. Results are shown on Table 3-1 and Figures 3-1 and 3-2. Figure 3-1 illustrates the containment vapor temperature response. The peak containment vapor temperature remains bounded by the power uprate results. Figure 3-2 illustrates the containment pressure for limiting cases. The peak MSLB pressure remains bounded by power uprate, however the peak LOCA pressure increased slightly. Safety related electrical equipment qualification impacts are discussed in section 8.

It was demonstrated that the RCS loop subcompartment pressure remains bounded by previous analysis.

Nine transients were analyzed for the temperature response in the MSVR. These transients included a break spectrum from 0.4 ft2 to 0.05 ft2 and power levels of 102% and 70% of NSSS power. All of the nine transients with the RSGs result in temperature transients that are within the temperature envelope currently described in FSAR, Appendix 3J.

3.7 Summary of Conclusions

The RSG containment analyses demonstrate that the containment design pressure and temperature remain bounding for the LOCA and MSLB. Since the predicted LOCA pressure is higher than the power uprate analyses, the containment leakage testing pressure, P_a, must be increased. Subcompartment analysis demonstrates that the subcompartment pressure also remains bounded by the previous design basis analyses.

MSVR temperature transients with the Model 54F steam generators remain bounded by the previous design basis analyses.

3.8 References

1. SNC letter to NRC, "Joseph M. Farley Nuclear Plant Facility Operating Licenses and Technical Specifications Change Request for Power Uprating," 2/14/97.

2. NRC letter, "Amendments 137 to FOL NPF-2 and 129 to FOL NPF-8," April 29, 1998 and August 20, 1998. (related to power uprate)

TABLE 3-1

Containment High Energy Line Break Results

HELB Case	Peak Pressure (psig)	Peak Temperature (°F)
SGR LOCA DEHL, 3 psig	43.8	264
SGR LOCA DEPSG, 3 psig	43.8	263
SGR MSLB, case 1, -1.5 psig	39.3	367
SGR MSLB, case 8, 3 psig	47.5	330
SGR MSLB, case 9, 3 psig	49.9	346
SGR MSLB, case 12, 3 psig	50.7	331
SGR MSLB, case 13, 3 psig	52.0	342
Uprate [illegible] A DEHL, 3 psig	43.0	263
Uprate LOCA DEPSG, 3 psig	41.5	261
Uprate MSLB case 1, -1.5 psig	41.9	383
Uprate MSLB case 9, 3 psig	52.3	288
Uprate MSLB case 12, 3 psig	52.4	347

FIGURE 3-1 Composite Temperature Data (MSLB and LOCA)

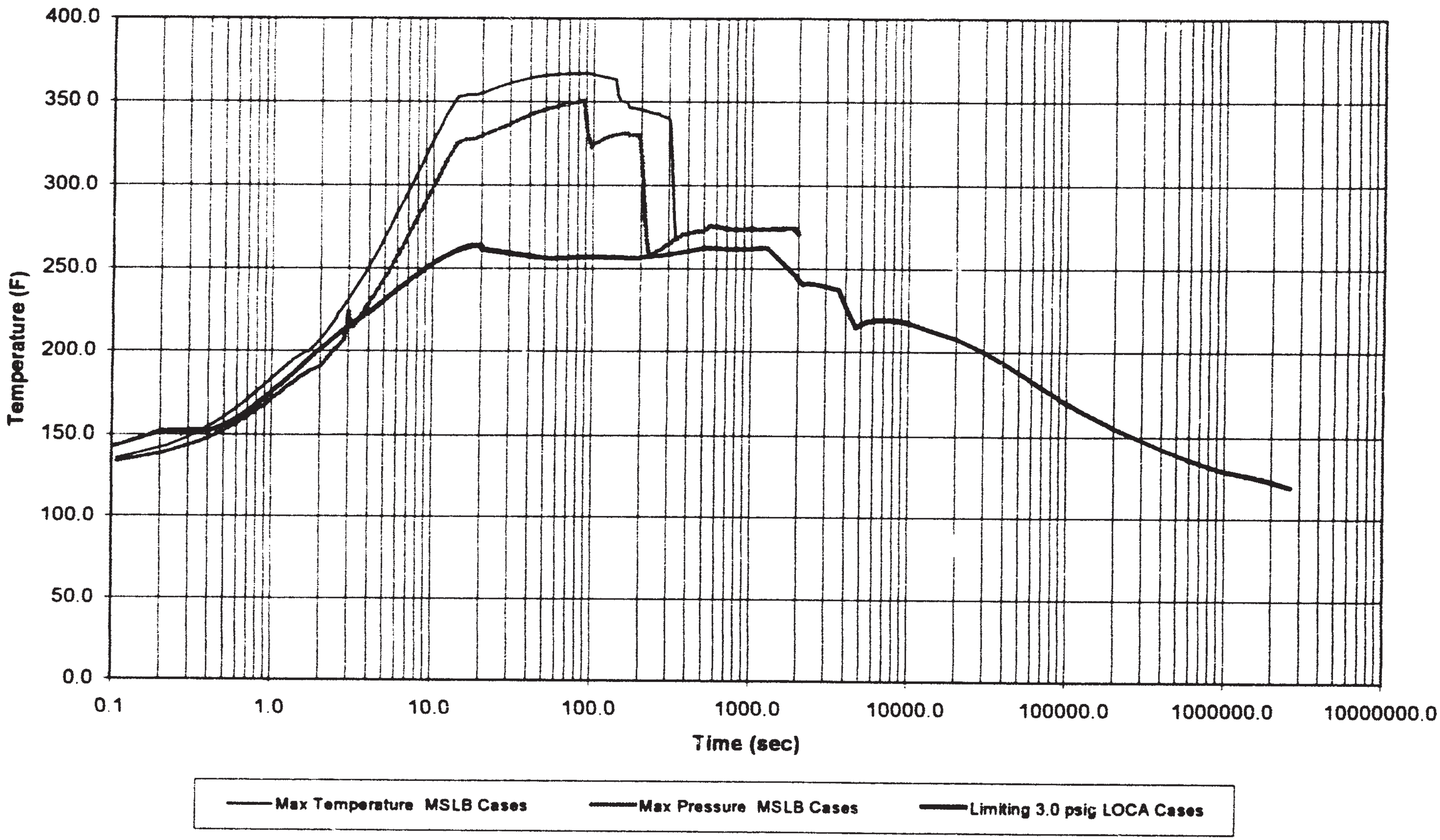
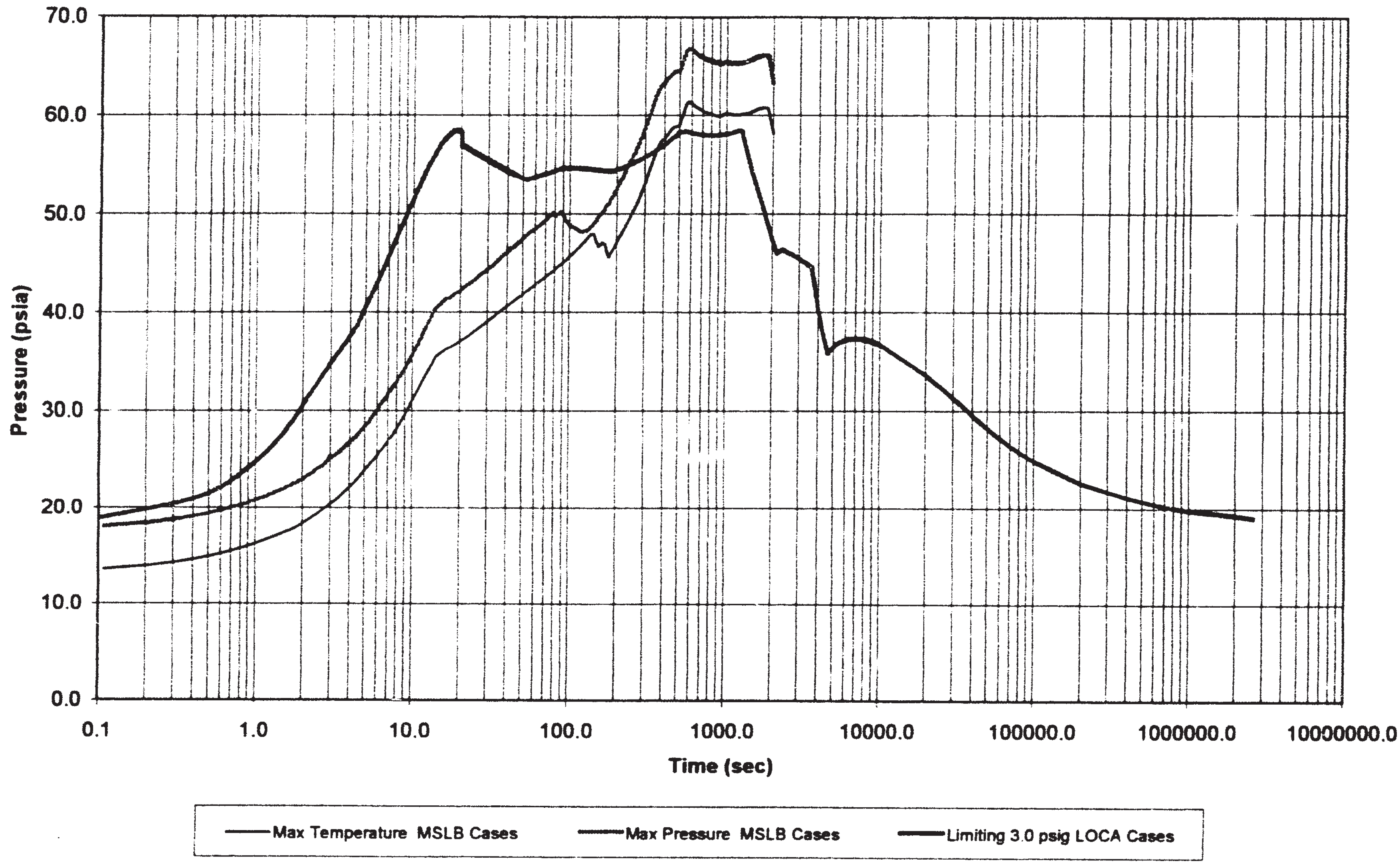


FIGURE 3-2 Composite Pressure Data (MSLB and LOCA)



4.0 POST LOCA HYDROGEN GENERATION

4.1 System Description

Hydrogen is generated following a loss of coolant accident (LOCA) inside containment from the following sources:

- Zirconium-water reaction;
- Corrosion of materials inside containment;
- Radiolytic decomposition of core and sump solution;
- Hydrogen present in the reactor coolant and pressurizer vapor space.

To maintain hydrogen concentration below four volume percent within containment, the following systems are provided:

- Hydrogen recombiners;
- Post accident containment venting system;
- Post accident containment mixing system;
- Post accident combustible gas sampling system.

The hydrogen recombiner system consists of two redundant (100% capacity) recombiners, which are designed to remove hydrogen at a design process flow rate of 100 CFM. Plant procedures indicate the recombiners are placed in service within one hour after the LOCA; however, credit is conservatively taken for their operation one day after the start of LOCA. For conditions beyond design basis accidents, the containment venting system is provided as a backup to the hydrogen recombiner system for combustible gas control. This system is designed to sequentially pressurize the containment, thus reducing the hydrogen concentration, and then to provide venting to remove hydrogen thereby maintaining the concentration levels below the lower flammability level of four volume percent. A post accident containment mixing system and containment building design promote mixing of the atmosphere. The post accident containment sampling system provides a means to monitor the hydrogen concentration.

There are no significant differences between Units 1 and 2 that need to be considered in the post-LOCA hydrogen generation analysis.

4.2 Design Interfaces

From the containment temperature accident analysis, the LOCA temperature profile is utilized as an input for evaluating the corrosion rate of containment materials, which generate hydrogen.

4.3 Scope of Review

The effect of steam generator replacement is reviewed for the above modes of hydrogen production post LOCA and capability of the combustible gas control system to maintain acceptable hydrogen concentration inside the containment.

4.4 Major Input Parameters and Assumptions

As a result of steam generator replacement, the containment temperature LOCA profile was affected and was therefore considered in the temperature dependent corrosion rate of aluminum and zinc quantities to generate hydrogen located in containment.

4.5 Method of Evaluation

The power uprate hydrogen generation model, based on Regulatory Guide 1.7, was used to evaluate the changes reflecting the steam generator replacement LOCA temperature profile from Section 3.

4.6 Summary of Evaluation

The results of the post accident hydrogen generation analysis are provided in Tables 4-1 and 4-2 and Figures 4-1 and 4-2. Due to the changes in modeling aluminum and zinc corrosion, the hydrogen generation rate increases, though the hydrogen concentration inside containment remains well below the lower flammability limit.

4.7 Summary of Conclusions

The results of the analysis indicate the post accident hydrogen concentration inside containment will not exceed the lower flammability limit of 4 volume percent with the operation of one hydrogen recombiner 24 hours after the start of the accident.

In the unlikely event both recombiners fail to start, containment pressurization would be initiated at day 5 following an accident with purging initiated at day 7 at a flow rate of 54 scfm. The dose for the low population zone due to containment purging has been calculated and was determined to be 86 REM thyroid and 0.4 REM whole body. With post-LOCA containment purge initiated at 7 days, the dose for the site boundary is outside the initial 2 hours for determining site boundary dose and is not calculated. The dose due to containment purging added to the doses from other post accident consequences are within the limits of 10 CFR 100.

The increase in hydrogen generation rate due to steam generator replacement is determined to have a negligible effect on the hydrogen recombiners, post accident venting, post accident hydrogen mixing or sampling systems.

TABLE 4-1. POST ACCIDENT HYDROGEN GENERATION WITH HYDROGEN RECOMBINER IN SERVICE

TIME (DAYS)	SUMP RADIOLYSIS (CU. FT.)	CORE RADIOLYSIS (CU. FT.)	AL & ZN CORROSION (CU. FT.)	HYDROGEN RECOMBINER (CU. FT.)	GRAND TOTAL* (CU. FT.)	CONTAINMENT CONCENTRATION (% VOL)
0						0
1	4956	2793	23748	0	47937	2.71
10	11025	15330	34326	<32631>	44489	2.52
20	14385	25410	39905	<62344>	33796	1.93
30	16485	33705	45484	<85426>	26688	1.53
40	18165	40845	51064	<104201>	22313	1.28
50	19530	47145	56643	<120262>	19495	1.12
60	20790	52815	62222	<134575>	17692	1.02
70	21840	58170	67801	<147752>	16500	0.95
80	22785	63105	73381	<160126>	15585	0.90
90	23730	67620	78960	<171879>	14871	0.86
100	24675	72030	84539	<183211>	14474	0.83

*** - GRAND TOTAL INCLUDES THE HYDROGEN GENERATED DUE TO ZR-WATER REACTION (15,410 CU. FT.) AND HYDROGEN PRESENT IN RCS AND PRESSURIZER VAPOR SPACE (1030 CU. FT.)**

TABLE 4-2. POST ACCIDENT HYDROGEN GENERATION WITH CONTAINMENT PURGE

TIME (DAYS)	SUMP RADIOLYSIS (CU. FT.)	CORE RADIOLYSIS (CU. FT.)	AL & ZN CORROSION (CU. FT.)	CONTAINMENT PURGE (CU. FT.)	GRAND TOTAL* (CU. FT.)
0					
1	4956	2793	23748	0	47937
10	11025	15330	34326	<8229>	68892
20	14385	25410	39905	<30446>	65694
30	16485	33705	45484	<46953>	65161
40	18165	40845	51064	<58053>	68460
50	19530	47145	56643	<74643>	65115
60	20790	52815	62222	<85554>	66713
70	21840	58170	67801	<99403>	64848
80	22785	63105	73381	<107676>	68035
90	23730	67620	78960	<124091>	62659
100	24675	72030	84539	<132335>	65350

*** - GRAND TOTAL INCLUDES THE HYDROGEN GENERATED DUE TO ZR-WATER REACTION (15,410 CU. FT.) AND HYDROGEN PRESENT IN RCS AND PRESSURIZER VAPOR SPACE (1030 CU. FT.)**

FIGURE 4-1. POST ACCIDENT HYDROGEN CONCENTRATION WITH CONTAINMENT PURGE

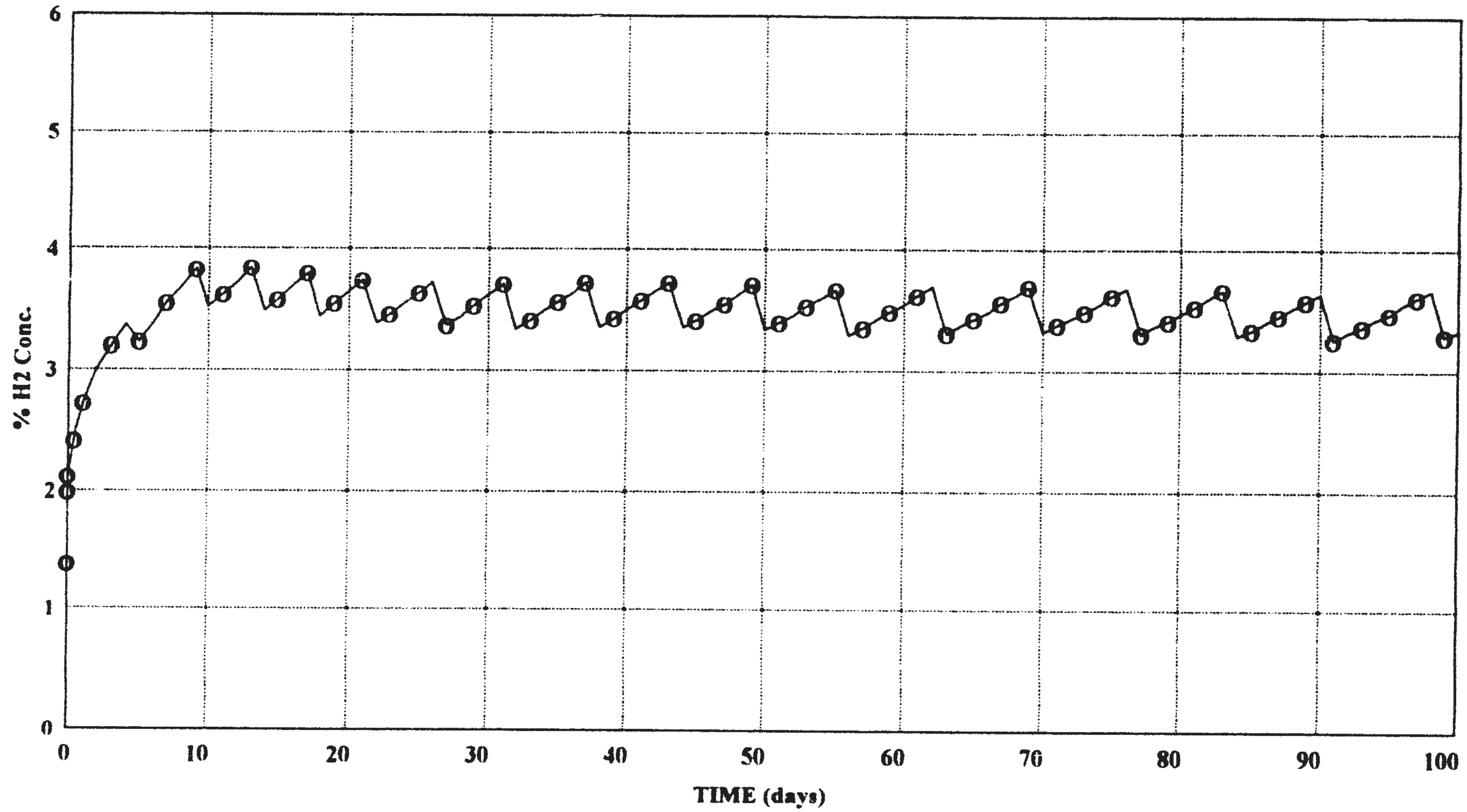
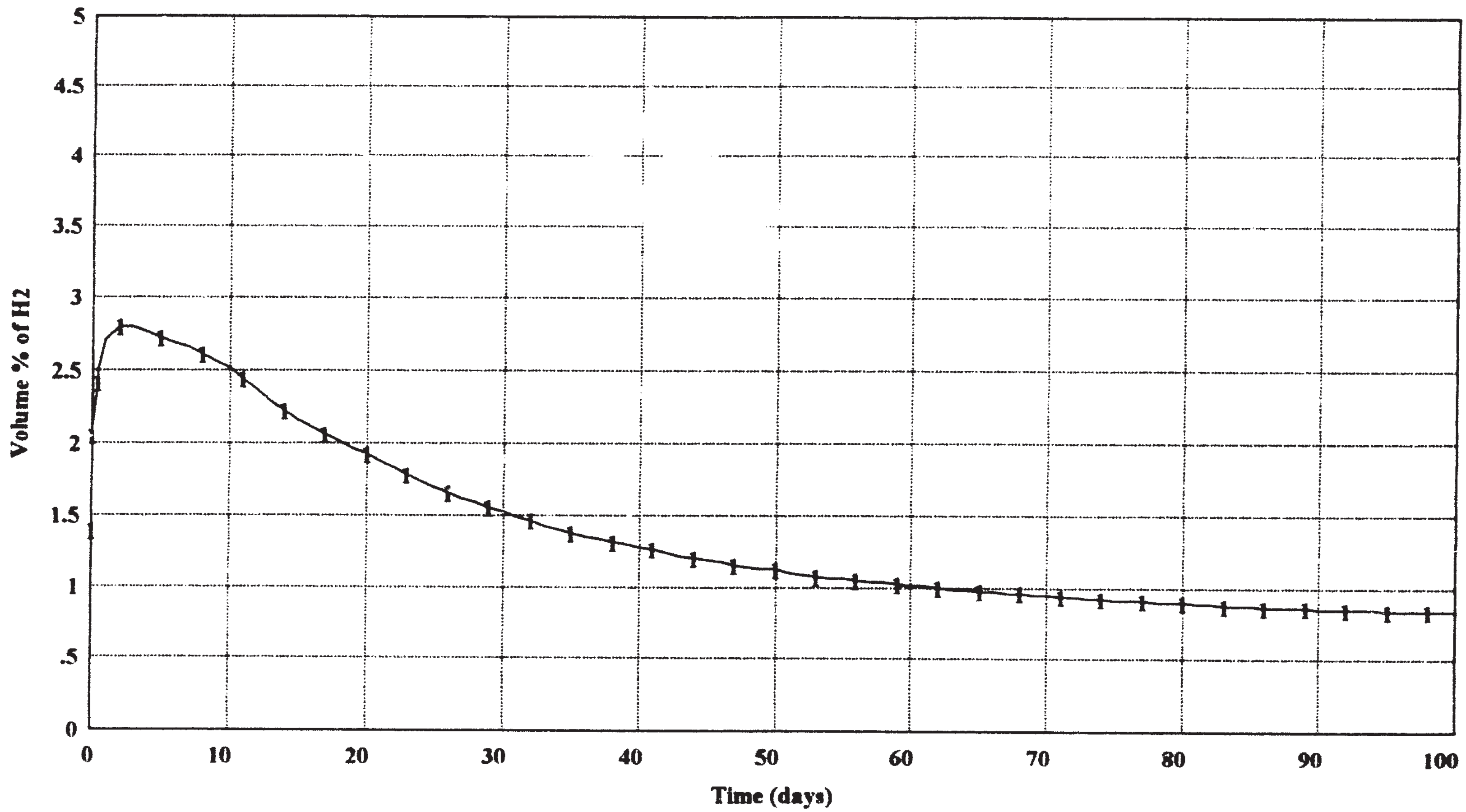


FIGURE 4-2. POST ACCIDENT HYDROGEN CONCENTRATION WITH HYDROGEN RECOMBINER IN SERVICE



5.0 RADIOLOGICAL ASSESSMENT

5.1 Description

The impact of steam generator replacement (SGR) on radiological analyses is comprised of three main topics. 1) The slightly increased RCS mass affects the radioactive inventory and may affect the specific activity in the RCS, which may affect shielding or accident release source terms. 2) The slight changes in steam generator fluid mass and change in level setpoints affect the radioactive inventory in the steam generators. 3) Higher RCS leakage and secondary side steam releases during accidents may affect radioactive releases and resultant doses.

There are no differences in input data or assumptions between Unit 1 and Unit 2; thus, the analyses are applicable to both units.

5.2 Design Interfaces

The radiological analyses are dependent on RCS activities and the core inventory that did not change with RSG. Therefore, the shielding and onsite dose evaluation did not proceed beyond review of the source terms.

For normal offsite releases and doses, interfaces include all potentially radioactive systems, structures and components, as well as the environs around the plant (*e.g.*, atmospheric parameters, ground and river water, aquatic and terrestrial plant and animal life, *etc.*). Input to the normal offsite releases and doses from the FSAR Chapter 11 was reviewed and no significant changes were identified that could impact normal offsite releases or doses.

Interfaces for the individual accident offsite analyses vary with the accident. Each accident requires input of source terms and mass release data. RCS activities and the core inventory from power uprate did not change with RSG. Mass release data are provided in the NSSS Licensing Report, WCAP 15098. Additional interfaces are with radioactivity transport pathways, fission product cleanup and removal systems and components, and atmospheric transport.

5.3 Scope of Review

For steam generator replacement, core and RCS design source terms revised for power uprate were reviewed and determined to be bounding. Power uprate radiological accident calculations were prepared for an RCS iodine concentration of 0.5 µCi/gm DEI^{131}[1], with the exception of the main steam line break which was prepared for an RCS iodine concentration of 0.15 µCi/gm DEI^{131}[2]. For the SGR accident analyses, the RCS iodine concentration is assumed to be 1.0 µCi/gm DEI^{131}. This bounds the previous power uprate analyses, is consistent with the NRC analyses[3], and supports an increase in the Technical Specifications RCS activity to 0.5 µCi/gm DEI^{131}.

SGR accident analyses assume RCS leakage is 1 gpm, which bounds the power uprate and current Technical Specifications values, and is consistent with the maximum values allowed per standard technical specifications. To address the secondary side steam releases of item 3 above, radiological consequences were generated for the following accidents:

- Steam Generator Tube Rupture (SGTR);
- Main Steam Line Break (MSLB);
- Loss of Offsite Power (LOSP);
- Turbine Trip/Loss of Load (TT/LOL);
- RCP Locked Rotor (LR)

Power uprate RCS and core source terms remain bounding and there are no changes to input parameters for other accidents (*e.g.*, containment, auxiliary building, or control room models, control rod ejection mass releases, fuel handling, radwaste, or HVAC systems, *etc.*). Therefore, the bounding LOCA control room doses and offsite doses for control rod ejection, waste gas decay tank rupture, fuel handling accident, and LOCA (except hydrogen purge contribution, see Section 4) were not re-evaluated. Further, normal shielding and operational dose rates are unaffected by SGR. RCS and steam generator secondary side mass changes are small and remain conservatively larger than the power uprate PWR-GALE code input values, therefore, design basis normal operation offsite releases and the consequential offsite dose to the public were not recalculated for SGR. Doses to equipment are considered in the safety-related electrical equipment qualification evaluation in Section 8, and post accident impact on radiolytic hydrogen generation is evaluated in Section 4.

5.4 Assumptions

The major assumptions used in calculation of offsite doses are consistent with NUREG 0800 and the following assumptions

- Dose conversion factors are taken from International Committee on Radiation Protection Publication 30 in lieu of the Regulatory Guides or TID-14844

- Iodine spike models as described in the appropriate sections of NUREG-0800 are considered in those FSAR accidents which currently do not include them but were considered for power uprate[1]. Although not specifically required by NUREG-0800, a pre-existing iodine spike is also modeled for the LOSP to provide a consistent treatment for all of the analyses

- Control room doses for large break LOCA were previously calculated and reported to the NRC for power uprate[1]. Control room doses for accidents other than LOCA are less than those for the LOCA[2,3] and are not explicitly calculated for SGR

5.5 Method of Evaluation

Offsite dose calculations for accident releases were prepared using the multi-node TACT5 computer code. Initial activity and release transport along the applicable pathway nodes (*e.g.*, core to RCS to steam generator to the environment) to the environment are modeled for each accident. The results are compared to the applicable acceptance criteria as described in the Standard Review Plan

Offsite and control room doses must meet the guidelines of 10 CFR 100 and requirements of 10 CFR 50, Appendix A, General Design Criterion 19, respectively. Further acceptance criteria for specific postulated accidents are provided by the NRC in the "St ndard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edit ," NUREG-0800, which indicates each accident should be "within" (< 100%), "well within" (< 25%), or a "small fraction of" (≤ 10%) the 10 CFR 100 guidelines.

5.6 Summary of Evaluation

5.6.1 Shielding

As noted above, shielding is not impacted by steam generator replacement.

5.6.2 Normal Offsite Releases and Doses

As noted above, no significant changes to actual offsite gaseous and liquid releases and doses are expected, and no changes to radwaste system design or operation are required for steam generator replacement. Operation of the radwaste system(s) to maintain offsite releases and doses within limits after RSG will continue to be determined as required by the ODCM.

5.6.3 Accident Doses

5.6.3.1 Evaluation of the Radiological Consequences of a Steam Generator Tube Rupture

The radiological consequences of the SGTR were evaluated utilizing the assumptions of Standard Review Plan Section 15.6.3 as shown in Table 5-1. There is no tube uncovery but immediate flashing of primary to secondary leakage in the ruptured steam generator is modeled as discussed in the NSSS Licensing Report, WCAP-15098. Two cases were evaluated.

Case 1. An SGTR with a preaccident iodine spike of 60 μCi/ gm DEI^{131} results in offsite doses less than 10 CFR 100 guidelines, which meets the acceptance criteria.

	Thyroid Dose (Rem)	Whole Body Dose (Rem)	Beta Skin Dose (Rem)
EAB	131	0.26	0.22
LPZ	49	0.10	0.08

Case 2. An SGTR with an accident initiated iodine spike with an appearance rate 500 times the equilibrium rate, corresponding to an initial RCS activity of 1.0 μCi/gm DEI^{131} results in offsite doses that are a small fraction (10%) of the 10 CFR 100 guidelines, which also meets the acceptance criteria.

	Thyroid Dose (Rem)	Whole Body Dose (Rem)	Beta Skin Dose (Rem)
EAB	18	0.19	0.17
LPZ	7.3	0.07	0.07

The potential for uncovery of the steam generator tubes during the event was also evaluated. Assuming 1.0 μCi/gm DEI^{131} RCS activity and 1 gpm primary to secondary leak rate released directly to the environment (*i.e.*, no mixing with the secondary side water) for the first 30 minutes, the offsite doses remain a small fraction of the 10 CFR 100 guidelines.

5.6.3.2 Evaluation of the Radiological Consequences of a Main Steam Line Break

The radiological consequences of the MSLB were evaluated utilizing the assumptions of Standard Review Plan Section 15.1.5 as shown in Table 5-2, except that partition factors in the intact generators are assumed to be limited to 10. For the intact steam generators, there is no tube uncovery nor immediate flashing of primary to secondary leakage consistent with FSAR Section 15.4.2. Two cases were evaluated.

Case 1. An MSLB with a preaccident iodine spike of 60 μCi/ gm DEI^{131} results in offsite doses less than 10 CFR 100 guidelines, which meets the acceptance criteria.

	Thyroid Dose (Rem)	Whole Body Dose (Rem)	Beta Skin Dose (Rem)
EAB	7.4	1×10^{-2}	5.3×10^{-3}
LPZ	3.4	4.3×10^{-3}	2.5×10^{-3}

Case 2. An MSLB with an accident initiated iodine spike, with an appearance rate 500 times the equilibrium rate corresponding to an initial RCS activity of 1.0 μCi/gm DEI^{131}, results in offsite doses that are a small fraction (10%) of the 10 CFR 100 guidelines, which also meets the acceptance criteria.

	Thyroid Dose (Rem)	Whole Body Dose (Rem)	Beta Skin Dose (Rem)
EAB	6.9	9.7×10^{-3}	5.2×10^{-3}
LPZ	3.3	4.6×10^{-3}	2.6×10^{-3}

The potential for uncovery of the steam generator tubes during the event was also evaluated for SGR conditions. Assuming 1.0 μCi/gm DEI^{131} RCS activity and 1 gpm primary to secondary leak rate released directly to the environment (*i.e.*, no mixing with the secondary side water) for the first 30 minutes, the offsite doses remain a small fraction of the 10 CFR 100 guidelines.

5.6.3.3 Evaluation of the Radiological Consequences of a Loss of Offsite Power, Loss of Load, Turbine Trip

The radiological consequences of the bounding steam releases from a loss of offsite power, loss of load, and turbine trip were evaluated utilizing the assumptions of Standard Review Plan Sections 15.2.1-15.2-6 as shown in Table 5-3, except that partition factors are assumed to be limited to 10. There is no tube uncovery nor immediate flashing of primary to secondary leakage consistent with FSAR Section 15.2.9. These releases result in offsite doses which meet the acceptance criteria, *i.e.* a small fraction (10%) of 10 CFR 100 guidelines.

	Thyroid Dose (Rem)	Whole Body Dose (Rem)	Beta Skin Dose (Rem)
EAB	1.2	2×10^{-3}	2×10^{-3}
LPZ	0.89	1×10^{-3}	1×10^{-3}

The potential impact of uncovery of the steam generator tubes during the event(s) was also evaluated for SGR conditions. A pre-existing spike, which increases the RCS iodine concentrations to 60 μCi/gm DEI^{131}, and a 1 gpm primary to secondary leak rate released directly to the environment (*i.e.*, no mixing with the secondary side water) for the first 30 minutes result in a thyroid dose which remains a small fraction of the 10 CFR 100 guidelines.

5.6.3.4 Evaluation of the Radiological Consequences of an RCP Locked Rotor

The radiological consequences of RCP locked rotor releases assuming 20% of the fuel clad/pellet gas gap is released to the RCS with subsequent leakage to the steam generators and secondary side steam releases were evaluated utilizing the assumptions of Standard Review Plan Section 15.3.3 as shown in Table 5-4. These releases result in offsite doses that are a small fraction of the guidelines of 10 CFR 100, which meets the acceptance criteria.

	Thyroid Dose (Rem)	Whole Body Dose (Rem)	Beta Skin Dose (Rem)
EAB	6.0	0.65	0.57
LPZ	8.7	0.34	0.28

5.7 Summary of Conclusions

No changes or additions to structures, equipment, or procedures are necessary to provide adequate radiation protection for the operators or the public during normal or post-accident operations in support of steam generator replacement at Farley. The existing structures, systems, and components can safely handle the changes in post accident releases from the replacement steam generator conditions. The resulting doses are less than the 10 CFR 100.11 and 10 CFR 50, Appendix A, General Design Criterion 19 guidelines and are within the Standard Review Plan guidelines. Therefore, the radiological consequences acceptance criteria for postulated Condition II, III, and IV events are satisfied for the RSG program.

5.8 References

1. SNC letter to NRC, "Joseph M. Farley Nuclear Plant Facility Operating Licenses and Technical Specifications Change Request for Power Uprating," 2/14/97.

2. NRC letter, "Amendments 132 to FOL NPF-2 and 124 and NPF-8," October 29, 1997 (related to Specific Activity limits for primary-to-secondary leakage associated with a main steam line break accident).

3. NRC letter, "Amendments 137 to FOL NPF-2 and 129 to FOL NPF-8," April 29, 1998 and August 20, 1998 (related to power uprate).

TABLE 5-1

PARAMETERS USED IN STEAM GENERATOR TUBE RUPTURE ANALYSES

Core thermal power	2831 MWt
Intact steam generator tube leak rate	500 gpd per generator
Fuel defects	1 %[a]
Secondary side activity	0.1 μCi/gm DEI^{131}
Time to reactor trip	324 sec[b]
Time to isolate ruptured steam generator	30 min
Steam release from ruptured steam generator	1133 lb/sec (0-324 sec)[b] 79,000 lb (324 sec-30 min)
Steam release from two intact steam generators	2266 lb/sec (0-324 sec)[b] 422,000 lb (324 sec-2 hr) 934,000 lb (2-8 hr)
Iodine partition in steam generators (except flashing RCS-see below)	0.01
Feedwater flow to two intact steam generators	327,000 lb (0-2 hr) 981,000 lb (2-8 hr)
Reactor coolant released to the ruptured steam generator	31,200 lb (0-324 sec) 126,800 lb (324 sec-30 min)
Reactor coolant flashing fraction	0.21 (0-324 sec) 0.15 (> 324 sec)

a. Pre-accident iodine spike of 60 μCi/gm DEI^{131} or accident initiated iodine spike 500 times normal appearance rate for 1 μCi/gm DEI^{131}.

b. Steam release prior to reactor trip is to condenser; however, no credit is taken for partitioning or cleanup in the condenser.

TABLE 5-2

PARAMETERS USED IN STEAM LINE BREAK ANALYSES

Core thermal power	2831 MWt
Steam generator tube leak rate prior to accident	1 gal/min (500 gpd ruptured generator)
Fuel defects	1 %[a]
Secondary side activity	0.1 μCi/gm DEI^{131}
Iodine partition factor for steam release from ruptured steam generator	1.0
Iodine partition factor in intact steam generators prior to and during accident	0.1
Initial steam release from ruptured steam generator	461,000 lb (0-30 min)
Steam release from two intact steam generators (lb)(h)	333,000 lb (0-2 hr) 739,000 lb (2-8 hr)
Feedwater flow to two intact steam generators	459,000 lb (0-2 hr) 747,000 lb (2-8 hr)

a. A pre-existing iodine spike of 60 μCi/gm DEI^{131} or an accident initiated iodine spike 500 times the normal appearance rate for 1.0 μCi/gm DEI^{131} is assumed.

TABLE 5-3

PARAMETERS USED IN LOSS OF ac POWER ANALYSES

Core thermal power	2831 MWt
Steam generator tube leak rate	1 gpm
Fuel defects	1%[a]
Iodine partition factor in steam generators	0.1
Secondary side iodine activity	0.1 μCi/gm DEI^{131}
Steam release from three steam generators	538,000 lb (0-2 hr) 875,000 lb (2-8 hr)
Feedwater flow to three steam generators	728,000 lb (0-2 hr) 887,000 lb (2-8 hr)

a. A pre-existing iodine spike of 60 μCi/gm DEI^{131} is assumed.

TABLE 5-4

PARAMETERS USED IN RCP LOCKED ROTOR ANALYSES

Core thermal power	2831 MWt
Fuel defects	NA[a]
Steam generator tube leak rate	1 gpm
Activity released to RCS	20% of gap inventory
Secondary side iodine activity	0.1 μCi/gm DEI^{131}
Iodine partition factor in steam generators	0.01
Steam release from three steam generators	538,000 lb (0-2 hr) 875,000 lb (2-8 hr)
Feedwater flow to three steam generators	728,000 lb (0-2 hr) 887,000 lb (2-8 hr)

a. RCS activity (including iodine spike) is negligible compared to 20% gap release.

6.0 AUXILIARY FEEDWATER SYSTEM (AFWS)

6.1 System Description

The AFWS is designed to supply high pressure feedwater to the steam generators (SG) for removal of residual heat from the core during emergency and non-emergency conditions. The major mechanical components supporting this action include two motor-driven AFW (MDAFW) pumps and one turbine-driven AFW (TDAFW) pump as well as control valves, flow orifices, motor-operated isolation valves, and the condensate storage tank.

6.2 Design Interfaces

The condensate storage tank serves as the normal suction source for the MDAFW pumps and the TDAFW pump. The steam generator blowdown and sampling systems automatically isolate on any AFW pump start. See Table 6-1 for AFW interfaces with the various transients and postulated accident analyses.

6.3 Scope of Review

This analysis of steam generator replacement focuses on two areas: 1) the ability AFWS to respond to the accident scenarios for which it is modeled to respond, and 2) the adequacy of the condensate storage tank (CST) inventory for conditions specified for steam generator replacement. This analysis applies to both Units 1 and 2.

6.4 Major Input Parameters and Assumptions

As a result of the accident analysis associated with steam generator replacement, some of the design bases associated with the AFWS were expanded upon or revised.

The loss of normal feedwater (LONF) design basis requirement was revised from 350 gpm to two steam generators to 350 gpm to all three steam generators. To maintain a flow rate of 350 gpm, it was necessary to reduce the heat input into the RCS. Therefore, a requirement to trip 2 of the 3 RCPs within 10 minutes of the start of the LONF event is necessary if the steam dumps and the main steam atmospheric relief valves are not available.

The back pressure for the feedline break (FLB) / MSLB after isolation was revised from 1155 psia to 1130 psia.

The MSLB - core response case was added as a design basis. The design basis requirements are bounded by the results from the MSLB inside containment case.

With the replacement of the steam generators, the steam generator no load programmed level and low-low level setpoints changed, which resulted in an evaluation of the protected volume within the CST.

6.5 Method of Evaluation

The design basis calculations for AFW flows were reviewed and revised to reflect the input changes described above. The MSLB - core response case was included in the design basis for the AFWS.

The CST design was revie[illegible]ed to verify the adequacy of the protected volume within the CST to meet the design basis r[illegible]ements and Technical Specification Bases with the steam generator no load progra[illegible]l level and low-low level setpoint changes.

6.6 Summary of Evaluation

The loss of normal feedwater accident scenario review indicates that the existing AFWS will meet the flow requirement. For the feedline break/MSLB after isolation case, the steam generator backpressure was reduced to less than the backpressure modeled in the analysis. Therefore, previous analysis conducted for power uprate bounds the steam generator replacement case.

The MSLB - core response case is bounded by the design basis requirements and results from the MSLB inside containment case.

All other accident scenarios for which AFW is relied upon are unaffected as a result of steam generator replacement.

To meet the design requirements the CST must contain 134,000 gallons of water. To meet the Technical Specification Bases, 115,100 gallons of water is needed. Both conditions are bounded by the current protected volume (150,000 gallons) of the CST.

The TDAFW pump turbine operating parameters (*e.g.*, steam pressure) remain unchanged from those analyzed for power uprate.

6.7 Summary of Conclusions

As summarized on Table 6-1, the results of the AFWS evaluations indicate that the AFWS design requirements are fulfilled by the minimum available AFW pumps under the limiting conditions. The missile protected portion of the CST contains adequate water to meet design requirements for sizing and the Technical Specification Bases.

TABLE 6-1

AFW System Flow Parameter List

DESIGN BASIS EVENT DESCRIPTION	DESIGN BASIS REQUIREME..S AFW FLOW/SG PRESSURE	SG CONDITION	REMARKS
LOSS OF NORMAL FEEDWATER (LONF)/LOSP	≥350 GPM TOTAL TO 2 SGs (175 GPM EACH) AT 1137.6 PSIA	SG 2C ISOLATED	ACCEPTABLE 2 MDPs OPERATING
	≥350 GPM TO 3 SGs (123.3 GPM EACH) AT 1137.6 PSIA (Note 2)	N/A	BOUNDED BY FLOW to 2 SG CASE
MAIN STEAM LINE BREAK (MSLB) INSIDE CONTAINMENT	1. ≤ 836 GPM TO FAULTED SG F..ULTED SG @ 14.7 PSIA INTACT SGs @ 820 PSIA	SG 2B FAULTED	ACCEPTABLE ALL THREE PUMPS OPERATING AT MAXIMUM PERFORMANCE
	2. ≤ 2100 GPM TO ALL SGs FAULTED SG @ 14.7 PSIA INTACT SGs @ 300 PSIA	SG 1B FAULTED	
	3. ≤ 811 GPM TO FAULTED SG FAULTED SG @ 80 PSIA INTACT SGs @ 690 PSIA	SG 2B FAULTED	ALL SGs EXAMINED (WORST CASE REPORTED)
	4. ≤ 2100 GPM TO ALL SGs FAULTED SG @ 80 PSIA INTACT SGs @ 190 PSIA		
MAIN STEAM LINE BREAK (MSLB) OUTSIDE CONTAINMENT	1. ≥ 175 GPM TO FAULTED SG FAULTED SG @ 1100 PSIA INTACT SGs @ 1138 PSIA	SG 2C FAULTED	ACCEPTABLE 2 MDPs OPERATING
	2. ≤ 750 GPM TO FAULTED SG FAULTED SG @ 325 PSIA INTACT SGs @ 725 PSIA	SG 2B FAULTED	ALL PUMPS OPERATING AT MAX. PERF.
FEED LINE BREAK (FLB) W/O ISOLATION	≥150 GPM TO INTACT SGs AT 1130 PSIA	SG 2B FAULTED	ACCEPTABLE TWO MDPs OPERATING
		SG 2A FAULTED	ACCEPTABLE ONE MDP AND T..P OPERATING
FLB/MSLB (AFTER ISOLATION)	≥350 GPM TO INTACT SGs AT 1130 PSIA	SG 2C FAULTED	ACCEPTABLE 2 MDPs OPERATING
ACCIDENTAL DEPRZ. OF A SG BY INADVERTENT OPENING OF ARV OR MSSV	MAX FLOW TO ALL SGs ≤ 2200 GPM. MIN FAULT SG PRESSURE = 247.4 PSIA	N/A	ACCEPTABLE BOUNDED BY THE MSLB CASE
SMALL BREAK LOCA (SBLOCA)	≥227 GPM TO EACH SG AT 1144 PSIA	ALL SGs @ 1144 PSIA	ACCEPTABLE 1 MDP AND TDP OPERATING

DESIGN BASIS EVENT DESCRIPTION	DESIGN BASIS REQUIREMENTS AFW FLOW/SG PRESSURE	SG CONDITION	REMARKS
STEAM GENERATOR TUBE RUPTURE (SGTR)	≥150 GPM TO EACH SG AT 1100 PSIA	ALL SGs @ 1100 PSIA	ACCEPTABLE 2 MDPS OPERATING
MSLB - CORE RESPONSE	≤ 1000 GPM to FAULTED SG; ≤ 2200 GPM to ALL SGs	SEE MSLB INSIDE CTMT	ACCEPTABLE BASED ON MSLB INSIDE CTMT RESULTS
HELB (STEAM SUPPLY TO TDP)	≥285 GPM TO ALL SGs AT 1137.6 PSIA	SGs AT 1137.6 PSIA SGs AT 1137.6 PSIA	ACCEPTABLE MDP 1A OPERATING ACCEPTABLE MDP 2B OPERATING
NORMAL PLANT COOLDOWN	≥350 GPM TO 3 SGs AT 1020 PSIA	SGs AT 1020 PSIA SGs AT 1020 PSIA	ACCEPTABLE MDP 1A OPERATING MDP 2B OPERATING
STATION BLACK-OUT (SBO)	≥350 GPM TO ALL SGs AT 1137.6 PSIA	SGs AT 1137.6 PSIA	ACCEPTABLE U2 TDP OPERATING

Notes 1. The results reported here represent the worst case condition of steam generator combination, i.e., faulted or intact steam generators, and operating pump(s).

2. To reduce heat input into the RCS, 2 of the 3 RCPs are tripped within 10 minutes of the start of the LONF event if the steam dumps and the main steam atmospheric relief valves are not available.

7.0 ENVIRONMENTAL IMPACT EVALUATION

The Farley Nuclear Plant Final Environmental Statement (FES) evaluates the nonradiological environmental impact of the two units at Farley Nuclear Plant. The conclusions of the FES are based on review of information contained in the Environmental Report-Operating License Stage. This evaluation provides an assessment of operation of Farley Nuclear Plant with replacement steam generators. An environmental evaluation covering the storage of the old steam generators on site will be performed as part of the old steam generator storage facility design effort.

7.1 Scope of Review

This evaluation assesses the environmental impact of the proposed operation with Westinghouse Model 54F steam generators that replace the existing Westinghouse Model 51 steam generators.

The NRC approved power uprate for Farley Nuclear Plant Units 1 and 2 was based, in part, on an environmental impact evaluation(1) which compared the operating parameters for power uprate with the parameters and conclusions of the above referenced reports. The evaluation concluded that no significant environmental impact resulted from power uprate. This evaluation documents the assessment of the environmental impacts of operation of Farley Nuclear Plant with replacement steam generators. The assessment is based on comparison of operating parameters established for replacement steam generators with the conclusions of the environmental impact evaluation for power uprate(1). The environmental evaluation specifically considers effects on the following parameters:

<u>River Water / Service Water Intake System</u>

Withdrawal rate
Intake canal velocity

<u>Circulating Water System</u>

Changes in rate of cooling tower blowdown
Changes in temperature of cooling tower blowdown
Changes in makeup to the cooling towers
Changes in cooling tower drift
Changes in cooling tower chemistry
Changes in consumptive water use

<u>Groundwater Withdrawal System</u>

Changes in groundwater withdrawal to supply sanitary water system
Changes in groundwater withdrawal to supply fire protection system

<u>Radwaste Dilution System</u>

Changes in liquid radwaste which would impact dilution flows

River Discharge System

Changes in discharge flow or velocity
Changes in discharge temperature or thermal plume
Changes in discharge chemical composition

7.2 Summary of Evaluation

7.2.1 River Water Intake , Service Water, and Circulating Water System

The proposed operation of Farley Nuclear Plant with replacement steam generators will result in a negligible change in cooling tower duty as compared to the power uprate operating condition. No measurable change in evaporation, makeup, or cooling tower blowdown temperature will occur. Cooling tower flowrate does not change as a result of operation with replacement steam generators. Cooling tower drift, which is a function of flowrate, also does not change. No change in cooling tower blowdown chemistry or flowrate will occur. As there is no appreciable impact on cooling tower blowdown temperature, flow, or chemical composition, there will be no measurable change in discharge to the service water system or to the Chattahoochee River.

Therefore, the operating parameters evaluated with regard to potential for environmental impact associated with operation of Farley Nuclear Plant with replacement steam generators retain the same values as power uprate or are bounded by the values evaluated for power uprate.

7.2.2 Other Systems

Steam generator blowdown is diluted by the service water system and discharged to the Chattahoochee River. No significant changes in secondary side water chemistry are anticipated to support operation with the replacement steam generators. Therefore, no significant changes in blowdown chemistry or flowrate are anticipated. No significant change in liquid radwaste quantities or activity levels associated with operation with replacement steam generators that would increase the required radwaste dilution flow is expected.

No change in groundwater withdrawal required to supply the sanitary water system or fire protection system will occur from operation with replacement steam generators.

7.3 Summary of Conclusions

In accordance with the above evaluation, it can be concluded that no significant environmental impact will result from the proposed operation with the replacement Model 54F steam generators.

7.4 References

1. SNC letter to NRC, "Joseph M. Farley Nuclear Plant Facility Operating Licenses and Technical Specifications Change Request for Power Uprating," 2/14/97.

8.0 ENVIRONMENTAL QUALIFICATION of SAFETY-RELATED ELECTRICAL EQUIPMENT

8.1 System Description

Safety-related electrical equipment located in a harsh environment is qualified to remain functional during and following a design basis event. Non-safety-related electric equipment whose failure under postulated environmental conditions could prevent accomplishment of safety functions must also be environmentally qualified. Also, certain post-accident monitoring equipment shall be environmentally qualified.

8.2 Design Interfaces

For the EQ evaluation, composite containment pressure and temperature curves were developed from the containment evaluation for pressure and temperature following a LOCA or MSLB, and a composite temperature curve was developed from various steam line breaks outside containment for the main steam valve room (MSVR).

8.3 Scope Of Review

The EQ dose limits for equipment located in a harsh environment were reviewed. Due to changes in the mass and energy releases following a design basis accident with the replacement steam generators, the containment pressure/temperature accident analysis and MSVR temperature accident analysis required a review of the composite pressure and temperature curves for equipment qualification. Components that were qualified based on calculated surface temperatures were also reviewed as part of the EQ evaluation by comparing the original qualification containment temperature composite curves with the containment temperature curves developed for the steam generator replacement (SGR) accident analysis. The maximum containment sump submergence level was also reviewed.

8.4 Method of Evaluation

The Environmental Qualification Program is established to meet the requirements of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." Specific design requirements (environmental conditions) are identified in FSAR Table 3.11-1 and the various EQ Packages.

The source terms developed from power uprate were evaluated to consider parameter changes due to steam generator replacement.

SGR containment temperature curve was compared to the composite curve developed due to power uprate (see Figure 8-1). For the equipment test profile that does not envelope the composite SGR temperature profile, the SGR LOCA profile was compared to the uprate LOCA profile (see Figure 8-2), and the SGR MSLBs were compared to the uprate MSLBs and their impact on the existing surface temperature analysis was evaluated.

Similar to the composite temperature profile, a composite pressure profile based on the postulated MSLBs and the LOCA profile for SGR was compared to the composite pressure profile developed for power uprate (see Figure 8-3).

Accident analysis profiles developed as a result of various breaks outside containment in the MSVR for SGR were compared to the composite profile referenced in FSAR Figure 3.11-4.

8.5 Summary of Evaluation

The source terms used to evaluate the radiological doses for equipment in a harsh environment remain applicable for the SGR project. As a result, the cumulative radiation dose for rooms located in a harsh environment is unaffected and remains applicable for SGR.

Comparison of the SGR composite temperature profile to the power uprate composite temperature profile indicates that the SGR maximum accident temperature of 367°F is 16°F less than the power uprate maximum accident temperature of 383°F. Thus, SGR would provide additional peak temperature margin. The power uprate composite temperature profile, except from the 10 second to 16 second point and for approximately 278 hours after the 1300 second point, envelopes the SGR composite temperature profile (see Figure 8-1). These two areas are discussed below.

During the first 16 seconds the SGR temperatures are approximately 11°F higher than the power uprate temperatures for less than 6 seconds (see Figure 8-1). The higher SGR temperatures are for a relatively short duration and considering the thermal lag time associated with increasing the temperature of the containment, the initial higher temperatures would not have an impact on equipment qualification.

After the 1300 second point, while the temperature is decreasing, the SGR temperatures exceed the power uprate temperatures by approximately 47°F (see Figure 8-1). The equipment qualification test temperature profiles have enough margin to envelop these short-term higher temperatures.

Comparison of the SGR LOCA temperature profile to the power uprate LOCA temperature profile indicates that the SGR LOCA temperatures are greater than the power uprate LOCA temperatures (up to 47°F) except for the 170 seconds (from the 30 second point to the 200 second point) when the power uprate temperatures are approximately 2°F greater than the SGR temperatures (see Figure 8-2). The SGR maximum accident temperature of 264°F is 1°F greater than the power uprate maximum accident temperature of 263°F. The equipment qualification test temperature profiles have enough margin to envelop these higher temperatures.

Comparison of the SGR composite pressure profile to the power uprate composite pressure profile indicates that the SGR maximum accident pressure of 52 psig is approximately 1 psig less than the power uprate maximum accident pressure of 53 psig. The power uprate composite pressure profile, except for the first 23 seconds and after approximately 2300 seconds, envelopes SGR composite pressure profile (see Figure 3). These two areas are discussed below.

During the first 23 seconds the SGR pressures are approximately 4 psig higher than the power uprate pressures for less than 13 seconds (see Figure 3). The peak test pressures during environmental testing are higher than the SGR calculated pressures, and there is sufficient margin in the test profiles to demonstrate that the equipment is able to function at the SGR pressures. Since the higher SGR pressures are for a relatively short duration, the initial higher pressures would not have an impact on equipment qualification. In addition, there is adequate margin between the SGR composite profile and the power uprate composite profile between the 23 second point and the 2300 second point to compensate for the time when the SGR composite profile is slightly higher than the power uprate composite profile.

After the 2300 second point, while pressure is decreasing, the SGR pressures exceed the power uprate pressures by approximately 10 psig (see Figure 8-3). There is adequate margin in the environmental test profiles to demonstrate that the equipment is able to function at the SGR pressures. The descending test pressure ramps are stepped, so the equipment is subjected to multiple pressure changes, which are more severe than the gradual SGR pressure changes at the lower pressures.

There is adequate margin in the environmental qualification testing of safety-related electrical equipment to demonstrate that the equipment installed at FNP is able to function at the SGR temperatures and pressures.

A review of the surface temperature analysis showed that the maximum temperature for the MSLB cases used in the design basis surface temperature analysis was greater than or comparable with the corresponding SGR MSLB cases. Therefore, revision of the surface temperature analysis is not required for SGR and the original results are bounding.

In the MSVR analysis, the mass and energy releases associated with SGR did not affect the composite temperature profile shown in FSAR Figure 3.11-4, which remains bounding. Therefore, no specific EQ evaluation was necessary for equipment located in the MSVR.

The maximum containment sump level analysis did not affect the submergence level elevation of 115'-0" used for evaluating EQ components.

8.6 Summary of Conclusions

The results of the radiological analysis for equipment in a harsh environment prepared for power uprate remains applicable with SGR.

At SGR MSLB/LOCA temperature and pressure conditions, the safety-related electrical equipment inside containment remains environmentally qualified. Comparing the surface temperature design basis MSLB cases to the comparable SGR MSLB cases shows that the original surface temperature results remain bounding and, therefore, are not impacted by SGR.

The composite temperature profile, shown in FSAR Figure 3.11-4 for a steam line break in the MSVR remains bounding.

The maximum containment sump level remains at elevation 115'-0".

FIGURE 8-1

FNP COMPOSITE LOCA/MSLB CONTAINMENT TEMPERATURE PROFILE

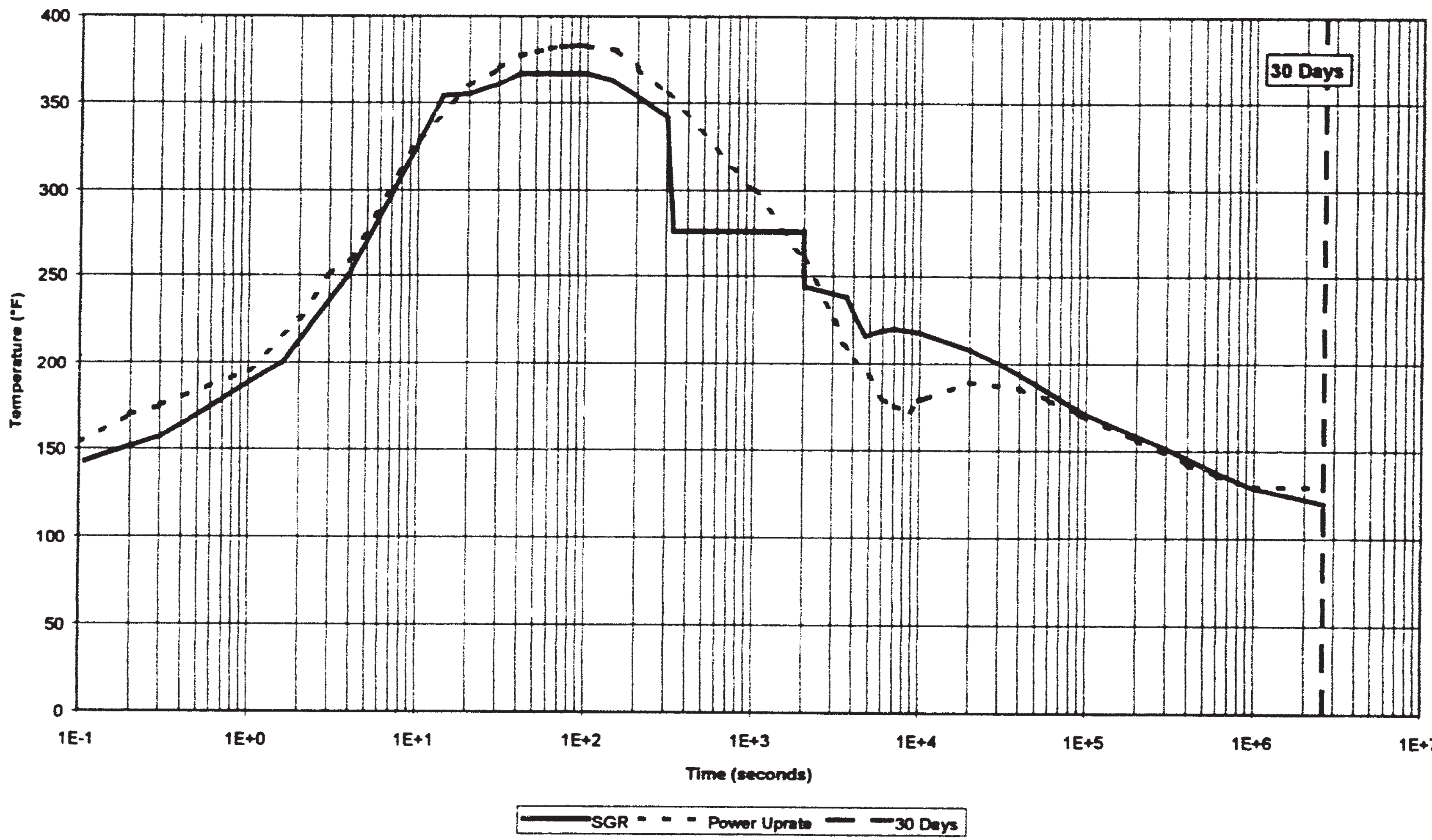


FIGURE 8-2

FNP LOCA CONTAINMENT TEMPERATURE PROFILE

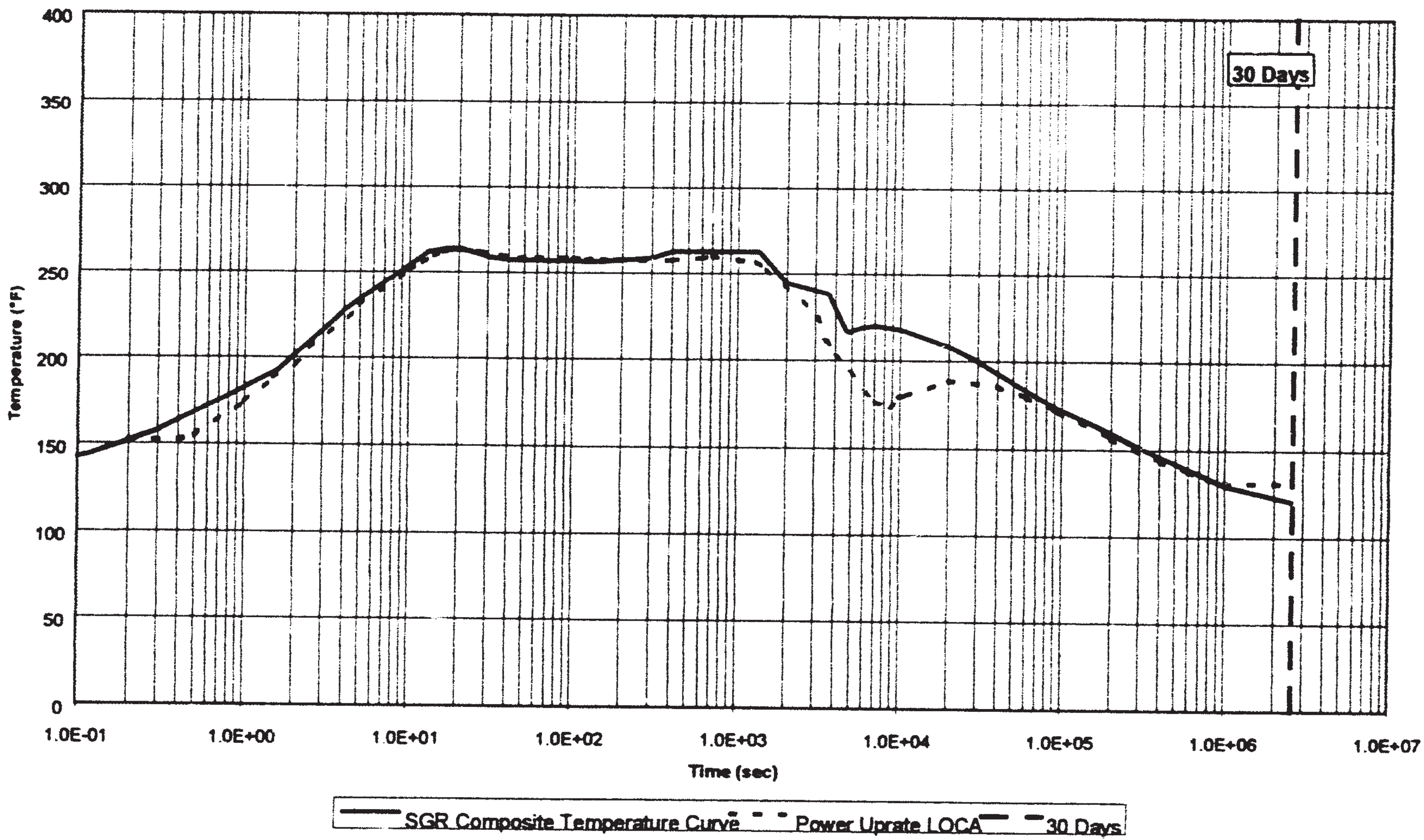
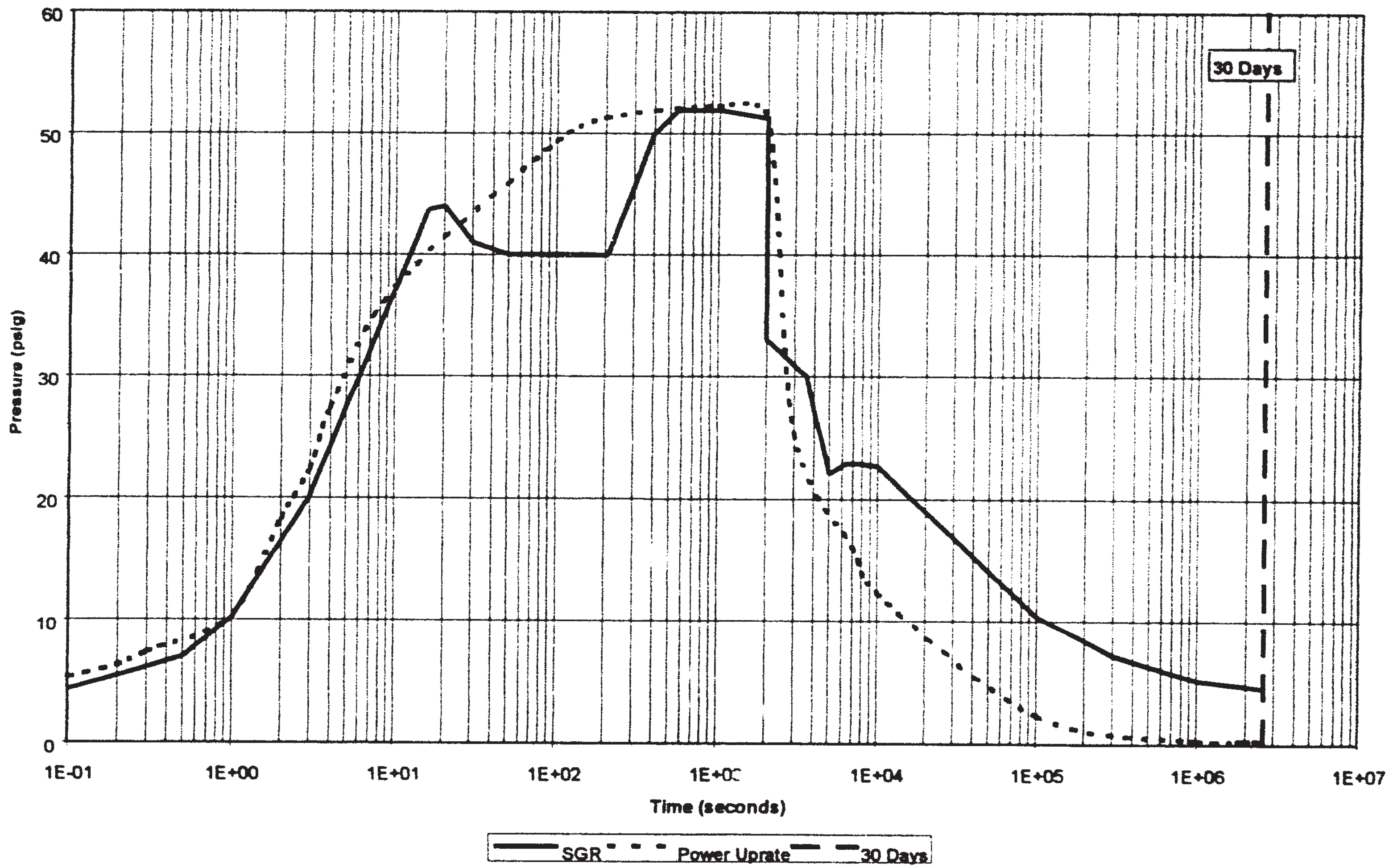


FIGURE 8-3

FNP COMPOSITE LOCA/MSLB CONTAINMENT PRESSURE PROFILE



9.0 Conclusion

A detailed review of systems, structures, and components not covered by the NSSS Licensing Report has been completed. The effects of replacing the steam generators with Model 54F steam generators were evaluated for BOP systems, structures and components that may be impacted. These systems, structures, and components are bounded by current design criteria and analyses, or the impacts on their function and operation have been analyzed or evaluated to have no significant impact on the function or operation. Evaluation of programmatic issues such as ALARA, Environmental Qualification, Environmental Protection, *etc.* determined that there is no significant impact due to operating conditions with the replacement Model 54F steam generators. Based on the results presented in this report, it is concluded that operation with the Model 54F steam generators will have no significant impact on the design or licensing basis of FNP.